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Power and Transmission Rate Orders and Related Documents Office of Power Marketing Coordination

Data Compiled January 1, 1980 through December 31, 1981

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**U.S. Department of Energy
Assistant Secretary for Conservation and Renewable Energy**

Published August 1982

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Power and Transmission Rate Orders and Related Documents

Office of Power Marketing Coordination

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U.S. Department of Energy
Assistant Secretary for Conservation and Renewable Energy
Washington, D.C. 20585

Published August 1982

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PREFACE

This booklet is the second and continuing publication of power and transmission rate orders and related documents issued by the Department of Energy. It covers calendar years 1980 and 1981. The first publication, DOE/CE-007 covering the period from March through December 1979, was published July 1981.

Prior to the establishment of the Department of Energy, power from Federal projects was marketed by five power marketing agencies under the Department of the Interior. These were the Alaska Power Administration (APA), the Bonneville Power Administration (BPA), the South-eastern Power Administration (SEPA), the South-western Power Administration (SWPA), and the United States Bureau of Reclamation (USBR).

The Department of Energy was established by the Act of August 4, 1977, P.L. 95-91, and began functioning officially on October 1, 1977. Under Section 302 (a) of that act, the four power administrations, namely, APA, BPA, SEPA, and SWPA, were transferred from the Department of the Interior to the Department of Energy, as separate and distinct organizational entities within the new Department. The same section also transferred the power marketing and transmission functions of the Bureau of Reclamation to be performed through a separate and distinct administration within the new Department. The new administration became the Western Area Power Administration.

Section 301(b) of the Department of Energy (DOE) Act transferred to and vested in the Secretary of Energy the function of the Federal Power Commission (FPC) to confirm and approve rates.

Under the ratemaking process in effect prior to the establishment of DOE, the rates and charges for electric power by the then four power administrations were prepared by the individual Administrators and approved by the Secretary of the Interior subject to confirmation and approval by the FPC, except for Snettisham Project rates that were approved by the Secretary of the Interior. The rates and charges for electric power marketed by the USBR, except for the Falcon-Amistad Projects, were subject to final approval of the Secretary of the Interior.

Transmission rates for BPA were subject to FPC confirmation and approval, but transmission rates for APA,

SEPA, SWPA and USBR were placed in effect by the Administrator or the Secretary of the Interior.

The Secretary of Energy initially authorized the Economic Regulatory Administration (ERA) to confirm and approve all Federal power rate adjustments formerly requiring FPC approval and to give final approval to power rate adjustments for Reclamation projects. This authority was granted under Delegation Order No. 0204-4, effective October 1, 1977.

In order to eliminate the role of ERA and to establish a uniform rate approval process for all five power administrations under DOE, the Secretary of Energy, on December 21, 1978, signed Delegation Order No. 0204-33 (43 FR 60636, December 28, 1978). This order delegated to the Assistant Secretary for Resource Applications the authority to confirm, approve, and place in effect power and transmission rates on an interim basis and delegated to the FERC the authority to confirm and approve such rates on a final basis. The delegation order became effective January 1, 1979. Due to a Department of Energy organizational realignment on February 24, 1981, the authority of the Assistant Secretary for Resource Applications was transferred, effective March 19, 1981, to the Assistant Secretary for Conservation and Renewable Energy.

Consistent with P.L. 96-501 (Regional Act) and the supplement to Delegation Order No. 0204-33 effective June 19, 1981, the authority of the Assistant Secretary for Conservation and Renewable Energy to approve rates for the Bonneville Power Administration extended only to December 5, 1981, after which time the FERC became solely responsible for the approval of BPA's rates.

This publication is a compilation of all rate orders issued by the Assistant Secretary for Resource Applications and the Assistant Secretary for Conservation and Renewable Energy during calendar years 1980 and 1981 under Delegation Order No. 0204-33. It also includes all final approvals, remands, and disapprovals by the FERC*, and a petition to the FERC for reconsideration by a Power Marketing Administration during 1980 and 1981. For ready reference, also included are two delegation orders along with an amendment and a supplement to one delegation order, a departmental order on financial reporting, and Power and Transmission Rate Adjustment Procedures relating to Federal power marketing.

James A. Braxdale
Editor

Washington, D.C.
August 1982

*FERC, as referred to in this publication, includes the Director, Office of Electric Power Regulation, who was delegated authority by the Commission to take action on uncontested rates effective as of May 22, 1981.

TABLE I
OFFICE OF POWER MARKETING COORDINATION
ASSISTANT SECRETARY FOR RESOURCE APPLICATIONS (To 2/24/81)
ASSISTANT SECRETARY FOR CONSERVATION AND RENEWABLE ENERGY (From 2/25/81)
RATE ORDERS ISSUED CY 1980 & 1981

<i>Power Administration Order</i>	<i>DOE Rate Order</i>	<i>Project or System</i>	<i>Date Issued</i>	<i>Effective Date</i>	<i>Date Published in Fed. Reg.</i>	<i>Federal Register Reference</i>
Alaska	APA-3	Snettisham	3-20-80	4-1-80	3-20-80	45 FR 19599
Alaska	APA-4	Eklutna	11-20-80	1-1-81	11-26-80	45 FR 78758
Bonneville	BPA-3	System & Transmission	7-1-80	7-1-80	7-10-80	45 FR 46471
Bonneville	BPA-4	System	6-24-81	7-1-81	6-30-81	46 FR 33542
Bonneville	BPA-5	Transmission	6-24-81	7-1-81	6-30-81	46 FR 33565
Southeastern	SEPA-7	Kerr-Philpott	4-22-80	7-1-80	4-30-80	45 FR 28800
Southeastern	SEPA-8	Cumberland Basin	5-22-80	7-1-80	5-30-80	45 FR 36471
Southeastern	SEPA-9	Georgia-Alabama	9-12-80	10-1-80	9-19-80	45 FR 62720
Southeastern	SEPA-10	Jim Woodruff	9-30-80	10-20-80	10-6-80	45 FR 66204
Southeastern	SEPA-11	Kerr-Philpott	9-14-81	10-1-81	9-18-81	46 FR 46381
Southeastern	SEPA-12	Georgia-Alabama	12-18-81	*	12-29-81	46 FR 62926
Southwestern	SWPA-4	System	3-19-80	4-1-80 & 1-1-79	3-25-80	45 FR 19303
Southwestern	SWPA-5	Narrows	6-6-80	7-1-80	3-12-80	45 FR 39954
Southwestern	SWPA-6	Transmission	7-1-80	7-1-80	7-10-80	45 FR 46477
Southwestern	SWPA-7	Transmission	12-11-80	1-1-81	12-17-80	45 FR 83011
Southwestern	SWPA-8	System	3-27-81	4-1-81	4-1-81	45 FR 19849
Western	WAPA-3	Parker-Davis	5-15-80	6-16-80	5-21-80	45 FR 34046
Western	WAPA-5	Central Valley	10-3-80	11-1-80	10-10-80	45 FR 67442
Western	WAPA-4	Colo. River Storage	12-23-80	1-23-81	12-31-80	45 FR 86988
Western	WAPA-6	Parker-Davis	5-14-81	6-16-81	5-21-80	45 FR 34046
Western	WAPA-8	Central Valley- Centralia	6-19-81	4-1-81	7-1-81	46 FR 34402
Western	WAPA-9	Fryingpan Arkansas	7-10-81	7-11-81	7-20-81	46 FR 37321
Western	WAPA-10	Central Valley	9-16-81	11-1-81	9-29-81	46 FR 47655
Western	WAPA-7	Colo. River Storage	12-18-81	1-23-82	12-29-81	46 FR 62927

*Effective with date of Duke Wheeling charge to SEPA.

TABLE II
FEDERAL ENERGY REGULATORY COMMISSION
Actions on Rate Orders in CY 1980 & 1981

<i>Power Administration</i>	<i>Power or System</i>	<i>DOE Rate Order</i>	<i>FERC Docket No.</i>	<i>Date FERC Order Issued</i>	<i>Date Published in Fed. Reg.</i>	<i>Federal Register Reference</i>	<i>FERC Action</i>
Alaska	Snettisham	APA-1	EF79-1021	12-2-80	12-8-80	45 FR 80868	Approved
Alaska	Eklutna	APA-2	EF80-1011	8-3-81	—	—	Approved Ltr. 6/26/80
Bonneville	Power and Transmission	BPA-3	ER80-167	6-26-80	—	—	Approved
Bonneville	System	BPA-2	EF80-2011	11-21-80	12-1-80	45 FR 79545	Remanded ¹
Bonneville	Transmission	BPA-1	E - 9563	12-1-80	12-8-80	45 FR 80882	Remanded ²
Southeastern	Georgia-Alabama	SEPA-3	EF79-3012	1-22-80	2-28-80	45 FR 13187	Approved
Southeastern	Kerr-Philpott	SEPA-7	EF80-3041	1-29-81	2-5-81	45 FR 10994	Approved
Southeastern	Cumberland Basin	SEPA-4	EF79-3021	2-27-81	3-3-81	46 FR 14941	Approved
Southeastern	Georgia-Alabama	SEPA-5	EF79-3011	4-3-81	4-8-81	46 FR 21076	Approved
Southeastern	Jim Woodruff	SEPA-6	EF80-3031	4-9-81	4-14-81	46 FR 21813	Approved
Southwestern	Transmissicn	SWPA-3	EF79-4051	12-2-80	12-8-80	45 FR 80879	Approved
Southwestern	Narrows	SWPA-5	EF80-4031	1-2-81	1-13-81	46 FR 3053	Approved
Southwestern	Sam Rayburn	SWPA-2	EF79-4021	1-8-81	2-12-81	46 FR 12065	Approved
Southwestern	System & Aluminum	SWPA-1	EF79-4011	6-3-81	6-11-81	46 FR 30877	Disapproved ³
Southwestern	Transmissicn	SWPA-7	EF81-4051	7-31-81	—	—	Approved
Western	Parker-Davis	WAPA-3	EF80-5041	10-29-81	—	—	Approved

¹Remand without prejudice. Resubmitted to FERC on 7-10-81.

²Remand without prejudice. Resubmitted to FERC on 11-13-81.

³Petition for reconsideration filed with FERC on 7-1-81.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR
RESOURCE APPLICATIONS

In the Matter of:

Southwestern Power Administration—) Rate Order
System Rates;) No. SWPA-4
Aluminum Contract Rates

ORDER EXTENDING CONFIRMATION
AND APPROVAL OF POWER RATES
ON AN INTERIM BASIS
(March 19, 1980)

Pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act, Public Law 95-91, the functions of the Secretary of the Interior and the Federal Power Commission under Section 5 of the Flood Control Act of 1944, 16 U.S.C. 825s, relating to the Southwestern Power Administration (SWPA) were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 F.R. 60636 (December 28, 1978) the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve, and place in effect such rates on an interim basis, and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. This rate order is issued pursuant to the delegation to the Assistant Secretary.

BACKGROUND

On March 1, 1979, the Assistant Secretary for Resource Applications issued Rate Order No. SWPA-1, an Order Confirming, Approving and Placing Increased Power Rates in Effect on an Interim Basis in the matter of: Southwestern Power Administration—System Rates; Aluminum Contract Rates. The rates, along with the Rate Order, basic studies, comments, transcripts, and other material concerning the SWPA system power rate adjustment, were submitted to the FERC for confirmation and approval on a final basis pursuant to the authority vested in the FERC by Delegation Order No. 0204-33. The rates which were the subject of Rate Order No. SWPA-1 superseded the following SWPA rates:

Rate Schedule F-1, Firm Power
Rate Schedule P-2 (Revised), Peaking Power
Rate Schedule EE, Excess Energy
Rate Schedule IC, Interruptible Capacity

Contract Rate in Section 2, Contract No. 14-02-001-864, Tex-La Electric Cooperative, Inc. (through TP&L)

Contract Rates in Section 1.05(A) and 1.06, Contract No. Ispa-514, Arkansas Power & Light Company/Reynolds Metals Company

The public was invited to review and comment on the development of new system rates through Federal Register Notices published during 1978. The public participation process produced numerous and varied questions and comments, all of which were considered and many of which were accepted and incorporated in developing the revised rates which were confirmed, approved and placed in effect on an interim basis by Rate Order No. SWPA-1.

The text of Rate Order No. SWPA-1 provided responses to the major comments, criticisms and alternatives offered during the comment period. The order confirmed, approved and placed in effect on an interim basis new system rate schedules which increased average annual revenues by \$16.5 million, or about 33 percent above then-current rate levels for the integrated system in order to accomplish repayment. By Rate Order No. SWPA-1 the Assistant Secretary for Resource Applications confirmed and approved on an interim basis, the following five Rate Schedules and one Contract Rate for SWPA, to become effective April 1, 1979, and replace the four rate schedules and the first contract rate listed previously:

Rate Schedule P-3, Peaking Power
Rate Schedule F-2, Firm Power from Integrated System
Rate Schedule F-3, Firm Power through Oklahoma Utility Companies
Rate Schedule EE-2, Excess Energy
Rate Schedule IC-2, Interruptible Capacity
Contract No. 14-02-001-864, Section 2, Tex-La Electric Cooperative (through TP&L)

These rates were to remain in effect on an interim basis for a period of 12 months unless such period were extended or until the FERC confirmed and approved these or substitute rates on a final basis.

Also confirmed and approved on an interim basis, effective January 1, 1979, was the application of Rate Schedule P-3 under Section 1.05(A) of Contract No. Ispa-514, Arkansas Power & Light Company/Reynolds Metals Company (Aluminum Contract), to power and energy sales provided under Section 1.02 of that contract, and the application of Rate Schedule EE-2 under Section 1.06 to secondary energy sales provided under Section 1.04 of that contract. These rates were to remain in effect on an interim basis for five years or until the FERC confirmed and approved these or substitute rates on a final basis.

DISCUSSION

The FERC has informed us that confirmation and approval of Federal power rates on a final basis normally can be expected within a year. Due to the extraordinary number of Federal power rate orders submitted to the FERC within the past calendar year, it is apparent that this schedule cannot be met. It is necessary, therefore, for the Assistant Secretary for Resource Applications to extend interim approval of the SWPA Integrated System Rate Schedules and the Tex-La Electric Cooperative Contract Rate for an additional 1-year period. Because the Aluminum Contract Rates were confirmed and approved on an interim basis for a 5-year period, they require no extension.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby extend confirmation and approval on an interim basis, effective April 1, 1980, of Rate Schedules P-3, F-2, F-3, EE-2, IC-2 and the Contract Rate under Section 2 of the Tex-La Electric Cooperative, Inc. Contract No. 14-02-001-864. These rates shall remain in effect on an interim basis for a period of 12 months unless such period is again extended or until the FERC confirms and approves these or substitute rates on a final basis.

Issued at Washington, D.C. this 19th day of March 1980.

Ruth M. Davis
Assistant Secretary
Resource Applications

UNITED STATES OF AMERICA DEPARTMENT OF ENERGY ASSISTANT SECRETARY FOR RESOURCE APPLICATIONS

In the Matter of:

Alaska Power Administration—) Rate Order
Snettisham Project Power Rates) No. APA-3

ORDER CONFIRMING AND APPROVING EXTENSION OF POWER RATES ON AN INTERIM BASIS (March 20, 1980)

Pursuant to Section 302(a) of the Department of Energy Organization Act, Public Law 95-91, the functions of the Secretary of the Interior under Section 204 of the Flood Control Act of 1962, Public Law 87-874, 76 Stat. 1173, 1193, for the Snettisham Project were transferred to and

vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 F.R. 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve, and place in effect such rates on an interim basis and delegated to the Federal Energy Regulatory Commission the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. This rate order is issued pursuant to the delegation to the Assistant Secretary.

BACKGROUND

Rate Schedule SN-F-1, for wholesale firm power service from the Snettisham Project was approved by the Secretary of the Interior, effective December 1, 1973, through November 30, 1978. The rate schedule was subsequently extended on November 28, 1978, through March 31, 1979, under the authority of the Assistant Secretary for Resource Applications.

On March 9, 1979, the former Assistant Secretary for Resource Applications confirmed and approved a 12-month extension of the existing rate on an interim basis, effective April 1, 1979, 44 FR 16470 (March 19, 1979), and requested confirmation and approval on a final basis by the Federal Energy Regulatory Commission of an extension of Rate Schedule SN-F-1. The intent of the rate order was to request final approval for the period April 1, 1979, through November 30, 1983.

Inasmuch as the Federal Energy Regulatory Commission is not expected to complete its confirmation and approval of the Snettisham Project power rate by March 31, 1980, a further extension of the interim rate is necessary.

Information regarding the March 9, 1979, rate extension and this rate extension, including studies, comments, transcripts and other supporting material, is available for public review in the offices of the Alaska Power Administration, Room 825, Federal Building, 709 West Ninth Street, Juneau, Alaska 99802 and in the office of the Director, Office of Power Marketing Coordination, 12th and Pennsylvania Avenue, NW., Washington, DC 20461.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, effective April 1, 1980, an extension of attached Rate Schedule SN-F-1 for the sale of power from the Snettisham Project by the Alaska Power Administration. This rate shall remain in effect on an interim basis for a period of 12 months unless such period is extended or until the Federal Energy Regulatory Commission confirms and approves it or a sub-

stitute rate on a final basis.

Issued at Washington, DC March 20, 1980.

Ruth M. Davis
Assistant Secretary
Resource Applications

Schedule SN-F-1

UNITED STATES
DEPARTMENT OF ENERGY
ALASKA POWER ADMINISTRATION

SNETTISHAM PROJECT, ALASKA

**SCHEDULE OF RATES FOR WHOLESALE
FIRM POWER SERVICE**

Effective:

December 1, 1973.

Available:

In the area served by the Snettisham Project, Alaska.

Applicable:

To wholesale power customers for general power service.

Character of Service:

Alternating current, 60 hertz, three-phase.

Monthly Rate:

CAPACITY CHARGE: None

ENERGY CHARGE: All energy at 15.6 mills per kilowatt-hour.

Minimum Annual Capacity Charge:

None

Minimum Annual Energy Charge:

As provided for under appropriate contract terms.

Adjustments:

For Transformer Losses:

If delivery is made at the high-voltage side of customer's substation but metered at the low-voltage side, the meter readings will be increased two percent to compensate for transformer losses.

For Power Factor:

The customer will normally be required to maintain a power factor at the point of delivery of no less than 90 percent. Adjustments for low power factor will be provided for under appropriate contract terms.

For Auxiliary Power Service:

Auxiliary power supplies may be used in conjunction with the service hereunder if the parties hereto, prior to the Contractor's utilization of any such auxiliary power supply, have entered into a written operating agreement defining the procedure by which the amount of power and energy supplied by the United States will be determined.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR
RESOURCE APPLICATIONS

In the Matter of:

Southeastern Power Administration—) Rate Order
Kerr-Philpott Projects' Power Rates) No. SEPA-7

ORDER CONFIRMING AND APPROVING
EXTENSION OF POWER RATES ON AN
INTERIM BASIS
(April 22, 1980)

Pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act, Public Law 95-91, the functions of the Secretary of the Interior and the Federal Power Commission under Section 5 of the Flood Control Act of 1944, 16 U.S.C. 825s, relating to the Southeastern Power Administration (SEPA) were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 F.R. 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve, and place in effect such rates on an interim basis and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. This rate order is issued pursuant to the delegation to the Assistant Secretary.

BACKGROUND

Power from the Kerr-Philpott Projects is presently sold under Wholesale Power Rate Schedules KP-1-B, KP-2-B and JHK-1-B. These rates were confirmed and approved by the Federal Power Commission on February 18, 1976, for a period ending June 30, 1980. SEPA is in the process of developing a new written power marketing policy for the Kerr-Philpott Projects and has requested that I approve a 15-months' extension of such rates to allow time to finalize the policy, renegotiate expiring contracts and permit applicable rates appropriate to such revised policy to be developed, confirmed and approved, and placed in effect.

DISCUSSION

Existing rate schedules are predicated upon a March 1975 repayment study and other supporting data all of which are contained in FPC Docket No. E-7002. However, expenses during Fiscal Years 1975 through 1979 were considerably less than estimated, such that at the

end of Fiscal Year 1979, the remaining unpaid investment allocated to the power function was approximately \$1,400,000 less than previously estimated. Furthermore, electric operating expenses for the Fiscal Years 1980 and 1981 are projected to essentially equal O&M estimates used for the 1975-79 period. Because of SEPA's favorable repayment position and because existing rates will continue to produce revenues during the interim extension period essentially adequate to repay costs associated with the production and transmission of power produced at the projects, it is appropriate to confirm and approve on an interim basis, an extension of existing rates as requested by SEPA.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, effective July 1, 1980, an extension of existing Rate Schedules KP-1-B, KP-2-B and JHK-1-B for the sale of power from the Kerr-Philpott Projects. The rate schedules, copies attached, as confirmed and approved hereby, shall remain in effect through September 30, 1981.

Issued at Washington, D.C., this 22nd day of April 1980.

Ruth M. Davis
Assistant Secretary
Resource Applications

UNITED STATES
DEPARTMENT OF THE INTERIOR
SOUTHEASTERN POWER ADMINISTRATION

**WHOLESALE FIRM POWER RATE
SCHEDULE KP-1-B**

Availability:

This rate schedule shall be available to public bodies and cooperatives (any one of which is hereinafter called the Customer) within a 150 mile radius of the John H. Kerr Project, purchasing power generated at the John H. Kerr and Philpott Projects in wholesale quantities under appropriate contracts and served through the facilities of the Virginia Electric and Power Company (hereinafter called the Company).

Applicability:

This rate schedule shall be applicable to firm power and accompanying energy generated at the John H. Kerr and Philpott Projects and to deficiency energy purchased by the Government from the Company, purchased in wholesale quantities under appropriate contracts for a specified number of kilowatts of capacity and shall be applied to each customer's system consisting of one or more delivery points.

Character of Service:

The electric capacity and energy supplied hereunder

will be 3-phase alternating current at a nominal frequency of 60 Hertz. The voltage of delivery will be maintained within the limits established by the state regulatory commission.

Monthly Rate:

The monthly rate for capacity and energy sold under this rate schedule shall be:

Demand Charge:

\$1.25 per kilowatt of contract demand.

Energy Charge:

5.00 mills per kilowatt-hour.

Contract Demand:

The contract demand is the amount of capacity in kilowatts stated in the contract which the Government is obligated to supply and the Customer is entitled to receive.

Energy to be Furnished by the Government:

The Government will sell to the Customer and the Customer will purchase from the Government energy each billing month equivalent to a total amount annually of 5,000 kilowatt-hours per kilowatt of contract demand prorated on an equal daily amount throughout the year. The Customer's contract demand and accompanying energy will be allocated proportionately to its individual delivery points served from the Company's system.

Billing Month:

The billing month for power sold under this schedule shall end at 12:00 midnight on the last day of each calendar month.

Conditions of Service:

The Purchaser shall at its own expense provide, install and maintain on its side of each delivery point the equipment necessary to protect and control its own system. In so doing, the installation, adjustment, and setting of all such control and protective equipment at or near the point of delivery shall be coordinated with that which is installed by and at the expense of the Company on its side of the delivery point.

Service Interruption:

When energy delivery to the Customer's system is reduced or interrupted for 1 hour or longer, and such reduction or interruption is not due to conditions on the Customer's system, the demand charge for the month shall be appropriately reduced.

July 1, 1975

UNITED STATES
DEPARTMENT OF THE INTERIOR
SOUTHEASTERN POWER ADMINISTRATION

**WHOLESALE POWER RATE
SCHEDULE KP-2-B**

Availability:

This rate schedule shall be available to the Carolina Power and Light Company and the Virginia Electric and Power Company (either one of which is hereinafter called the Company).

Applicability:

This rate schedule shall be applicable to electric capacity and energy generated at the John H. Kerr and Philpott Projects (hereinafter called the Projects) and sold under appropriate contracts between the Government and the Company.

Character of Service:

Electric capacity and energy delivered to the Company will be 3-phase alternating current at a nominal frequency of 60 Hertz delivered at points of delivery specified by appropriate contract.

Monthly Rate:

The monthly rate for capacity and energy sold under this rate schedule shall be:

Demand Charge:

\$1.25 per kilowatt per month for dependable capacity made available to the Company for their own use.

Energy Charge:

An amount for dump energy equal to eighty percent (80%) of the calculated saving in the cost of fuel for the Company's operating generating units due to the generation avoided therein by the delivery of such dump energy; provided, that the procedures to determine saving in the cost of fuel will be agreed upon from time to time by the Government and the Company.

Billing Month:

End-of-month meter readings shall be made at 12:00 midnight at the end of the calendar month where meters are located in continuously attended power plants and substations.

Service Interruptions:

When the dependable capacity available to the Company is reduced or interrupted for one hour or longer during on-peak hours and such reduction or interruption is not due to conditions on the Company's system, or in the case of Philpott, the Appalachian Power Company's or the Company's system, or agreed to outages, the dependable capacity to be paid for by the Company for that month shall be reduced for billing purposes for each on-peak hour (the nearest number of whole hours) that dependable capacity available to the Company is reduced or interrupted by an amount equal to one/(number of on-peak hours in the month) times such reduction in kilowatts of dependable capacity. In the event such reduction in dependable capacity to be paid for by the Company should be greater than the dependable capacity sold to the Company in any month, any such excess shall be ap-

plied to the dependable capacity sold to the Company in subsequent months. If such reduction or interruption results in a total delivery of energy in that month to or for the account of the Company's system by the Government amounting to less than the total declared available, the declaration of energy for that month shall be reduced for accounting purposes to the amount actually delivered. On-peak hours shall be the hours between 8:00 a.m. and 10:00 p.m. on all days except Sunday.

Power Factor:

The Company shall take power and energy from the Government at such power factor as will best serve the Company's system from time to time; provided, that the Company shall not impose a power factor of less than .85 lagging on the Government's facilities which requires operation contrary to good operating practice or results in overload or impairment of such facilities or unreasonably interferes with the delivery of power and energy by the Government to its other customers.

Termination of Contract:

The Company shall pay the Government 5.00 mills per kilowatt hours for energy remaining in the energy bank and for energy remaining as a net debit balance in the storage account at the termination of the contract between the Government and the Company.

July 1, 1975

UNITED STATES
DEPARTMENT OF THE INTERIOR
SOUTHEASTERN POWER ADMINISTRATION

WHOLESALE FIRM POWER RATE
SCHEDULE JHK-1-R

Availability:

This rate schedule shall be available to public bodies and cooperatives (any one of which is hereinafter called the Customer) within a 165 mile radius of the existing interconnection point between the Virginia Electric and Power Company and the Carolina Power and Light Company (hereinafter called the Company) at the Virginia-North Carolina State line in the vicinity of John H. Kerr Project (hereinafter called the Project), purchasing power from the Project in wholesale quantities under appropriate contracts and served through the facilities of the Company.

Applicability:

This rate schedule shall be applicable to Project firm power and accompanying energy, purchased in wholesale quantities under appropriate contracts for a specified number of kilowatts of capacity and shall be applied to each Customer's system consisting of one or more delivery points.

Character of Service:

Electric capacity and energy supplied hereunder will be

3-phase alternating current at a nominal frequency of 60-Hertz delivered at existing or future delivery points on the Company's transmission and distribution system.

Monthly Rate:

The monthly rate for capacity and energy sold under this rate schedule shall be:

Demand Charge:

\$1.25 per kilowatt of contract demand.

Energy Charge:

5.00 mills per kilowatt-hour.

Contract Demand:

The contract demand is the amount of capacity in kilowatts stated in the contract which the Government is obligated to supply and the Customer is entitled to receive.

Energy to be Furnished by the Government:

(a) If the Customer does not own or operate generating facilities (other than mobile generating equipment used for emergency purposes), the Government will supply Project energy to such Customer each month, to the extent that such energy is available, based on the ratio of the Customer's energy requirements (determined by multiplying the Customer's total energy requirements at all points of delivery located within 165 miles of the existing interconnection point between the Company and VEPCO at the Virginia-North Carolina State line in the vicinity of the Project by the ratio of the Customer's contract demand to its maximum 30-minute integrated measured demand for that month at said points of delivery) to the sum of the individual energy requirements of all such Customers purchasing under this rate schedule determined on this same basis. (The maximum 30-minute integrated measured demand of the Customer for the month shall be determined by adding together the highest 30-minute integrated measured demand at each point of delivery located within 165 miles of the aforementioned interconnection point, exclusive of abnormal non-recurring demands resulting from transfer of loads from one point of delivery to another where such transfers are previously approved by the Company.)

(b) If the Customer owns or operates generating facilities (other than mobile generating equipment used for emergency purposes), the Government will supply Project energy each month in an amount determined by multiplying the ratio of the Customer's contract demand to the dependable capacity made available to the Company's system from the Project by 100/106 of the total energy (exclusive of dump energy) declared and made available to the Company's system from the Project.

Energy Accounting:

For the purposes of energy accounting an energy bank shall be maintained, and the Government shall keep the official record of such account. In any month in which the total Project energy (exclusive of dump energy) declared and made available by the Government to the Company exceeds the energy accounted for in such month as ac-

companying the capacity required to meet the contract demands of the Government to preference customers, increased by six percent (6%) to provide for losses in transmission, such remaining energy shall be credited to the energy bank. Energy stored in this energy bank shall be used in subsequent months to supply to the extent possible preference customer energy requirements not supplied by energy declared and made available from the Project during such months. Withdrawals of energy from the energy bank shall reduce the bank account and shall be accounted for as Project energy available to be transmitted by the Company to the preference customers for the account of the Government.

In those months when Project energy (including energy available from the energy bank) multiplied by 100/106 is equal to or more than the total energy requirements of preference customers of the Government, all such energy requirements shall be deemed to have been supplied from the Project and transmitted by the Company for the account of the Government. In those months when Project energy (including energy available from the energy bank) multiplied by 100/106 is less than the total energy requirements of preference customers of the Government, the quantity of energy which shall be deemed to have been transmitted by the Company for the account of the Government shall be 100/106 of the total Project and bank energy available for transmission. In such months each preference customer of the Government that owns or operates generating facilities (other than mobile generating equipment used for emergency purposes) shall receive a portion of the available energy that results from multiplying the ratio of each such Customer's contract demand to the dependable capacity made available to the Company's system by 100/106 of the total energy declared and made available to the Company's system (excluding energy available from the energy bank), and each of the other preference customers of the Government shall receive a proportionate part of the remaining available energy based on the ratio of such Customer's individual energy requirements (determined by multiplying each such Customer's total energy requirements at all points of delivery by the ratio of its contract demand to its maximum 30-minute integrated measured demand for the month at said points of delivery) to the sum of the individual energy requirements of all such preference customers determined on this same basis.

Billing Month:

End-of-month meter readings for billing under this schedule shall be made on the last regular working day of each month or as near thereto as may be practicable.

Conditions of Service:

(a) Parallel Operation:

The Government may condition service to the Customer upon payment by the Customer to the Company of the cost of such facilities, including special meters, as are made necessary by the Customer's operation of any generating facilities in parallel with the Company's system and in such event will require the operation and mainte-

nance of such facilities by the Customer in accordance with good operating practices.

(b) Energy Scheduling:

If the Customer owns or operates generating facilities (other than mobile generating equipment used for emergency purposes), it shall schedule and receive its proportionate share of the minimum monthly declarations of energy as provided in the contract between the Government and the Company dated March 30, 1973, in quantities reasonably distributed over the period of declaration. In the event energy in addition to minimum is available at the Project, the Customer shall receive its proportionate share of any excess energy so declared during the period for which it is declared.

(c) Service Interruption:

When energy delivery to the Customer's system is reduced or interrupted for 1 hour or longer, and such reduction or interruption is not due to conditions on the Customer's system, the demand charge for the month shall be appropriately reduced.

(d) Power Factor:

If the Customer owns or operates generating facilities (other than mobile generating equipment used for emergency purposes), the Customer will so utilize its generating units and power factor corrective equipment as to minimize its reactive requirements; provided, however, that unless otherwise specifically agreed, the Government will not be obligated to make available for delivery power and energy to the Customer at any time at a power factor below .85 lagging.

July 1, 1975

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR
RESOURCE APPLICATIONS

In the Matter of:

Western Area Power Administration—) Rate Order
Parker-Davis Project Power and) No. WAPA-3
Transmission Rates

ORDER CONFIRMING, APPROVING, AND
PLACING INCREASED POWER AND
TRANSMISSION RATES IN EFFECT
ON AN INTERIM BASIS
(MAY 15, 1980)

Pursuant to Section 302(a) of the Department of Energy Organization Act, 42 U.S.C. 7152(a), the power marketing functions of the Secretary of the Interior under the Reclamation Act of 1902, 43 U.S.C. 372 *et seq.*, as amended and supplemented by subsequent enactments, particularly by Section 9(c) of the Reclamation Act of 1939, 43 U.S.C. 485h(c), and acts specifically applicable to the Parker-Davis Project, for the Water and Power Resources Service (formerly the Bureau of Reclamation)

were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 FR 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve, and place in effect such rates on an interim basis, and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. The rate order is issued pursuant to the delegation to the Assistant Secretary and the rate adjustment procedures at 43 FR 12076 (March 23, 1978), as amended by 44 FR 7796 (February 7, 1979).

BACKGROUND

Public Notice and Comment

On June 14, 1979, the Western Area Power Administration (Western) announced a tentative rate adjustment for Parker-Davis Project power marketed by Western (44 FR 34192). Interested persons were invited to participate in public forums and to submit written comments relative to the proposed rate adjustment. A public information forum was held in Las Vegas, Nevada, on July 9, 1979. The Boulder City Area Manager presented an overview of the project rate history, costs, and projected revenues and cost throughout the remainder of the repayment period. A question and answer session followed, after which the meeting was concluded. A public comment forum was held in Phoenix, Arizona, on August 31, 1979. Oral presentations were made by seven customer representatives, and one written comment was received.

Existing Rates

The wholesale firm power service rate subject to this order supersedes Rate Schedule LC-F2 (\$1.39/kW/mo and 3.5 mills/kWh), for wholesale firm power service from the Parker-Davis Project. The existing rate was approved by the Secretary of the Interior, effective on the first day of the first full billing period beginning on or after June 1, 1977.

The existing firm transmission service charge for the use of the Parker-Davis Project transmission system except for the transmission of Colorado River Storage Project (CRSP) power, was initially implemented by contract at \$5.30/kW/yr on March 1, 1976. There has been no transmission service charge for CRSP electric service customers utilizing the Parker-Davis Project transmission system for the transmission of CRSP power. The existing rate for nonfirm transmission service is 1.0 mill per kilowatt-hour.

Project History

The Parker Dam Power Project was authorized by Section 2 of the Rivers and Harbors Act of August 30, 1935 (49 Stat. 1039), and the Davis Dam Project was authorized April 26, 1941, by the Acting Secretary of the In-

terior under provisions of the Reclamation Project Act of 1939 (43 U.S.C. 485 *et seq.*). The Parker-Davis Project was formed by the consolidation of the two projects under the terms of the Act of May 28, 1954 (68 Stat. 143). Parker Dam, which creates the Lake Havasu reservoir, is located on the Colorado River between Arizona and California, 155 miles downstream from Hoover Dam. The dam was constructed by the Bureau of Reclamation, partially with funds advanced by the Metropolitan Water District of Southern California. Under the contract, the Metropolitan Water District is entitled to one-half of the net energy generated. Davis Dam, which creates the Lake Mohave reservoir, is located on the Colorado River between Arizona and Nevada, 67 miles downstream from Hoover Dam. The Parker-Davis Project is operated in conjunction with other hydroelectric installations in the Colorado River Basin.

Construction of Parker Dam was authorized for the purpose of controlling floods, improving navigation, regulating the flow of the streams of the United States, providing for storage and for the delivery of the stored waters thereof, for the reclamation of public lands and Indian reservations, and other beneficial uses, and for the generation of electric energy as a means of financially aiding and assisting such undertakings.

Davis Dam was constructed to provide reregulation of the fluctuating water releases from Lake Mead at Hoover Dam, from hourly to seasonal, to facilitate water delivery for downstream irrigation requirements, for delivery of water beyond the boundary of the United States as required by the Mexican Water Treaty, and for the generation of electric energy as a means of financially aiding and assisting such undertakings.

A total of 254,000 kilowatts is available from the Parker-Davis Project in the summer season, and 186,000 kilowatts in the winter season. Average annual generation is 1.2 billion kilowatthours. Transmission system capacity commitments were 933,625 kilowatts in FY 1977.

DISCUSSION

Power Repayment Study

The current power repayment study for fiscal year 1977 indicates that the existing power rates are inadequate, based on January 1977 price levels, to pay the costs allocated and assigned to the power function within allowable time periods. Such inadequate revenues would result in a deficit which would be due primarily to higher interest rates charged against the unamortized portion of new additions and replacement investment.

A revised power repayment study was conducted which indicated the average annual revenue would have to be increased about \$2.3 million to meet cost recovery criteria. New firm power rates and transmission charges were developed to generate the revenue required by the revised power repayment study.

Rate Design and Rates

A capacity and energy rate study and a transmission service charge study were made to assist in designing rates.

Estimated future power costs were examined to determine an appropriate apportionment between capacity and energy components. Analyses of future costs indicated it would be equitable and reasonable to split power production costs evenly between the capacity and energy components.

The annual charge for use of the Parker-Davis transmission system was developed based on annual transmission costs and capacity commitments for FY 1977. Of the total assumed transmission commitments of 613 MW in 1982 excluding Colorado River Storage Project, the new transmission rate of \$6.80/kW/yr would be applicable to 171 MW. The existing transmission rate of \$5.30/kW/yr cannot be changed at this time on some existing firm transmission contracts. The new seasonal charge of \$3.67/kW/season for the transmission of CRSP power was developed based on proportionate usage of the Parker-Davis transmission facilities. Nonfirm transmission service is, by its nature, intermittent and therefore was not considered to be a significant factor in rate setting and in the rate design. Revenues from project use and Government camps represent about 6 percent of the total power revenues. The rates for power for project use and for Government camps are not affected by this order.

The results of a revised power repayment study and subsequent rate design indicated that an average composite yield of 8.3 mills/kWhr, or a capacity component of \$1.82/kW/mo and an energy component of 4.15 mills/kWhr, for all wholesale firm power customers, would satisfy the repayment criteria. Over 60 percent of project power revenues would be received from firm power sales.

The transmission charges provide for: an increase of firm transmission service charge, as permitted under existing contracts, to \$6.80/kW/yr for the use of the Parker-Davis Project transmission system for firm transmission other than for Colorado River Storage Project power as permitted under existing contracts; implementation of a transmission charge of \$3.67/kW/season for the Colorado River Storage Project, Southern Division, contractors using the Parker-Davis Project transmission system for the transmission of Colorado River Storage Project power; and establishment, by rate schedule, of an increase to a 1.3 mills/kWh charge for nonfirm transmission service.

Surplus Energy Revenues

A number of the customers presented comments regarding the alleged failure of Western to consider the probability of surplus water releases previously forecasted by the Water and Power Resources Service which might result in surplus energy generation through Davis and Parker Powerplants. The customers contended that there is a high probability of surplus energy becoming available for sale during the time frame 1981 through 1985. It was

indicated that surplus energy sales would result in added revenues available for the project and thus eliminate the need for a power rate adjustment at this time or at least reduce the proposed rate adjustment.

Further, the Department of the Interior's Manual 730.4.7E (adopted by Department of Energy's Order RA 6120.2 dated September 20, 1979) was cited by the customers as the authority for Western to consider potential surplus revenues derived from anticipated higher than normal streamflows on the Colorado River. One customer stated that Western had acted contrary to the manual while another commented that Western chose to disregard the instructions.

It is noted that DM 730.4.7E and Department of Energy's Order RA 6120.2.10(e)(4), state, "Power quantities used for estimating revenues, unless defined by contract, are determined by the theoretical *reservoir operation studies* based on historical streamflows. In preparing these operational studies, hydrological data, current to within 5 years if possible, and available engineering data will be used, recognizing restrictions imposed by other project functions. Input data will be revised and updated whenever new information indicates that a significant change in the forecast can be expected in the future where there is a significant variance between the forecasted and actual results, but in any event not less frequently than once every 5 years unless an accepted explanation is provided concerning why this is not necessary." (Emphasis added.)

A reservoir operation study is a quantitative hydrology study which indicates the number of acre-feet of water which would be released and the number of kilowatt-hours which would be generated under a variety of water conditions, such as upper quartile, average, lower quartile, and adverse. Forecasts of energy sales and revenues are based on average water conditions.

The Water and Power Resources Service forecast relied on by the customers is a study of the probability of water releases for the purpose of flood control covering a relatively short time of the power repayment period. The study is not a reservoir operation study and does not indicate how much water will be released or the resultant energy that could be generated. A probability study simply indicates the likelihood of occurrence of a specific event; in this case, the likelihood that surplus water releases for flood control will occur in the 1981-1985 time frame. This likelihood, whether a surplus or a deficit, does not invalidate the use of average water conditions for forecasting energy sales and revenues as discussed above.

The repayment study does not show future costs for purchased power to meet contract commitments in low water years because the assumption is made that revenues from surplus energy sales would offset such costs. This assumption is favorable to the power customers. Consistent with this assumption, it would not be proper to make the further assumption that the possibility of surplus releases during the 1981-1985 period will become a reality. If such

surplus releases do occur, the resulting sales and revenues as reflected in historical accounts, will tend to reduce future rate increases that might be required.

Replacements

The customers commented on the method of forecasting replacement costs indicating that these costs may not be accurately projected and integrated into the repayment study. One commentator felt the power repayment study may be overstating the funds estimated for facilities replacement. The customers also were concerned that the 1968 Replacement Service Life Report used as a basis for forecasting future replacement cost may be outdated and in need of review.

The method of estimating future replacement costs in the repayment study was accomplished by a computer model developed by the Water and Power Resources Service. This computer model utilizes estimated service life values to calculate future replacements of plant investments. It should be noted that for the 5 succeeding years following the current study year, budget estimates are utilized for replacement costs. For the period following the 5 years, the computer model is employed to forecast future year replacement costs.

The 1968 Replacement Service Life Report is the Basis for the service lives utilized by the replacement computer program to project future replacement costs appearing in the power repayment study. The customers believe that some of the estimated service lives are unrealistic. Western acknowledged that the study is 10 years old and may require review. Therefore, correspondence with the Water and Power Resources Service was initiated suggesting a joint review of the service life report. It has been generally agreed that the review will require 18-24 months to complete. The customers have expressed a desire to be involved in this review and it is Western's intent to seek customer involvement. Appropriate notification will be given the customers as the review progresses. Any new service life study or revisions to the 1968 study will be reflected, when available, in future power repayment studies.

CRSP Transmission Charge

The question of the implementation of a transmission charge for delivery of CRSP power over the Parker-Davis system was presented by a number of customers. The comment made by three of the customers concerned the basis for the transmission charge to be levied by the Parker-Davis Project.

The General Marketing Criteria for Colorado River Storage Project published in the Federal Register on February 9, 1978 (43 FR 5559), specifically referred to transmission charges by other Federal projects. On page 5564 of the Federal Register notice, first column, paragraph D states: "WAPA will transmit CRSP power to customers over existing transmission systems of other projects to the extent that capacity is determined to be available. Capacity in these other project transmission

systems to the extent possible will be available for the term of the CRSP contracts involved. No additional charges will be imposed unless additional substation or switching station capacity is required or where utilization of another project's system would delay project repayment beyond the point in time which would otherwise be the case. *At some future date, the Secretary may charge for transmission service for delivery of CRSP power over other Federal Systems such as the Parker-Davis and Pick-Sloan Missouri Projects.* The customer will pay for such service at a rate determined by the Secretary which may be assessed as early as 1978 but shall not be later than the termination date of the customer's existing power sales contracts as they may be amended, or in any event, by October 1, 1989." (Emphasis added.)

We believe it is proper to charge those contractors/customers in the Southern Division of the Colorado River Storage Project for transmission of CRSP Energy over the Parker-Davis system. Those receiving the benefits of the service should defray the costs of service. It would not be equitable for those CRSP contractors utilizing the Parker-Davis system to continue receiving transmission service for their CRSP entitlement at no cost, at the expense of the other users of the Parker-Davis system.

One customer objected to the proposed transmission charge for wheeling CRSP power over the Parker-Davis system on the basis that it is not properly chargeable to individual customers but should be charged to the CRSP itself.

This question arose once before during the development of the revised CRSP "General Power Marketing Criteria" in 1976. The coordinating committee, which was comprised of representatives of the Water and Power Resources Service and of all CRSP customers, recommended the adoption of Section 10D of those criteria, which is quoted above. The coordinating committee recommended and DOE adopted these provisions on the basis of their being the most equitable solution to the problem of transmission costs for the delivery of CRSP power over other Federal systems.

Transmission Costs

One customer was in agreement with the concept that all users of the transmission system should bear the cost of the system. However, it was believed that all contractors/customers should participate proportionately with their usage. The customer expressed concern that "presently unrecovered costs" (due to some contractors not being subject to the increase at this time) should not be recouped in the future from contractors who are subject to the increase at this time, and that at the earliest possible date the impediments, not required by statute, which prevent application of increases to all transmission contractors should be removed.

There are contractual restraints in a few contracts that do not allow for a transmission rate adjustment at this time. Two of these contracts expire in 1987. The rates in these contracts will be adjusted at the earliest opportunity.

One representative pointed out differences between its actual transmission costs compared to those forecast in the brochure which suggested that the amount of the rate increase needed was overstated.

The differences stem from the estimate of future load based on contracts in effect in FY 1977. Since the repayment study was prepared, there have been numerous contract revisions and these will be reflected in future power repayment studies.

Future Transmission Capacity Commitments

It was indicated by one customer that Western's power repayment study excludes any growth in transmission capacity commitments through 1982 and therefore is unrealistic in view of growth of electric requirements. Further, because transmission capacity commitments for 1982 are claimed to be understated, the customer indicated that the projected revenues are also understated and the amount of the increase is overstated.

In estimating future revenues, Western's study was based on contractual commitments as of July 1977 or the best information available at the time of the study. To the extent any estimates of revenues (or costs) ultimately prove to be inaccurate, corrections will be made in future power repayment studies.

Leavitt Act

The Ak-Chin Indian Community argued that it was entitled to equitable relief from the new transmission charge for the delivery of CRSP power under the first provision of the Leavitt Act which authorizes and directs the Secretary of the Interior "... to adjust or eliminate reimbursable charges of the Government of the United States existing as debts against individual Indians or tribes of Indians in such a way as shall be equitable and just in consideration of all the circumstances under which such charges were made: . . . " (Act of July 1, 1932, 47 Stat. 564, 25 U.S.C. 386a.)

This portion of the Leavitt Act authorized the Secretary of the Interior to grant relief on a project-by-project basis from then existing obligations under the Indian Appropriations Act for Fiscal Year 1915 (Act of August 1, 1914, 38 Stat. 582, 583) to reimburse the Government for expenditures made for Indian irrigation projects. Neither it nor the first proviso, which defers construction costs assessed "against Indian owned lands within any Government irrigation project," applies to reclamation projects. Solicitor Finney Opinion, 54 I.D. 90(1932). Also, both portions of the acts, which derived from separate bills, provide relief only from irrigation costs and do not apply to power costs. Consequently, the Leavitt Act does not afford a basis for the requested relief.

Authority of Assistant Secretary for Resource Applications

One commentator disagreed that the Assistant Secretary for Resource Applications has the authority to set rates on a provisional basis, after which they are submitted to the Federal Energy Regulatory Commission for approval on a final basis.

My authority to confirm, approve and place rates in effect on an interim basis for the Parker-Davis Project stems from Delegation Order 0204-33, as explained in the first paragraph of this order. The legal issues raised by the comment are answered by the opinion of the General Counsel of the Department of Energy issued October 14, 1978, discussing a draft of the delegation order. In that opinion the General Counsel pointed out that the authority to establish rates on an interim basis "is a necessary corollary of, and inherent in, the basic authority to set rates."

Lower Colorado River Basin Development Fund

A written statement filed on behalf of the Central Arizona Water Conservation District and the State of Arizona asserted that the Colorado River Basin Project Act of 1968 (Public Law 90-537, 43 U.S.C. 1501 *et seq.*) makes it necessary to set power rates for the Parker-Davis Project at a level which will assure project payout no later than the year 2005. Thereafter, rates should be at a level that would provide surplus revenues which, along with surplus revenues from the Boulder Canyon Project and the Pacific Northwest-Pacific Southwest Intertie Project in Nevada and Arizona, would provide at least 24 percent of the reimbursable costs of the Central Arizona Project.

Section 403(c)(2) of the Colorado River Basin Project Act (43 U.S.C. 1543(c)(2)) provides that there shall be credited to the Lower Colorado River Basin Development Fund "... any Federal revenues from the Boulder Canyon and Parker-Davis Projects which, after completion of repayment requirements of the said Boulder Canyon and Parker-Davis Projects, are surplus, as determined by the Secretary, to the operation, maintenance, and replacement requirements of those projects...." Other provisions of the Act deal with the application and distribution of these funds.

The legislative history of the Act shows that Congress anticipated that the original investment in the Parker-Davis Project would be essentially paid off in the year 2005, after which surplus revenues would be available. The revised power repayment study shows that the payout target will be met, but the determination of a surplus is complicated by the unforeseen rise in the cost of additions and replacements and the interest charges thereon. The decision to implement some form of contribution from the Parker-Davis Project to the Lower Colorado River Basin Development Fund will need to be made at a later date to satisfy the original intent of Congress.

Environmental Assessment

One customer representative objected to the fact that an environmental assessment was not included with the preliminary rate proposal.

A study of the environmental and economic impacts of the proposed rate increase has been accomplished concurrent with the power repayment study. This study, called an environmental review, is designed to determine the extent of environmental impacts that can be expected

from the rate adjustment. Study results indicate that the proposed rate increase will not significantly affect air or water quality, recreation resources, fish and wildlife, or any physical operation criteria of the Colorado River or related power production facilities.

It is clear that the proposed rate increase are not major Federal actions significantly affecting the quality of the human environment, within the meaning of NEPA, and that no environmental impact statement or environmental assessment is required.

Public Utility Regulatory Policies Act 1978

Comments were made by numerous customer representatives regarding the applicability of the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601 *et seq.* (PURPA) to the Parker-Davis rate adjustment proceedings.

The PURPA Standards are not currently applicable to the rate adjustment proceedings because Parker-Davis did not have sales not for resale in excess of 500 million kilowatthours. However, some of the analyses suggested by the PURPA Standards may be included in the development of future proposed rates.

Suspend Proceedings

A request was made to the Administrator, by one representative, to suspend the rate proceedings because of a number of legal, procedural, and information deficiencies.

We are not aware of any valid basis that would justify suspending these proceedings.

Availability of Information

Information regarding this rate adjustment, including studies, comments, transcripts and other supporting material, is available for public review in the Boulder City Area Office, Western Area Power Administration, P.O. Box 200, Boulder City, Nevada 89005; Office of the Administrator, Western Area Power Administration, P.O. Box 3402, Golden, Colorado and in the Office of the Director of Power Marketing Coordination, 12th and Pennsylvania Avenue, NW., Washington, D.C. 20461.

Submission to the Federal Energy Regulatory Commission

The rates herein confirmed, approved, and placed in effect on an interim basis, together with supporting documents, will be submitted to the Federal Energy Regulatory Commission for confirmation and approval on a final basis.

Price Stability

Western is a "government enterprise" within the meaning of the price standards of the President's Council on Wage and Price Stability. The rate increase approved herein complies with the operating margin limitation of these standards because the revenues will be only those necessary to repay Parker-Davis Project costs and expenses.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, effective June 16, 1980, Rate Schedules PD-F1, PD-T1, PD-T2, and PD-T3 for wholesale power and transmission service. These rates shall remain in effect on an interim basis for a period of 12 months unless such period is extended, or until the FERC confirms and approves these or substitute rates on a final basis, whichever occurs first.

Issued at Washington, DC 15th day of May 1980.

Ruth M. Davis
Assistant Secretary
Resource Applications

Schedule PD-F1
(Replaces LC-F2)

UNITED STATES
DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

BOULDER CITY AREA

PARKER-DAVIS PROJECT, ARIZONA-
CALIFORNIA-NEVADA

SCHEDULE OF RATES FOR WHOLESALE FIRM POWER SERVICE

Effective:

The first day of the first full billing period beginning on or after June 16, 1980.

Available:

In the area served by the Parker-Davis Project.

Applicable:

To wholesale power customers for general electric service supplied through one meter at one point of delivery.

Character and Conditions of Service:

Three-phase alternating current at sixty (60) Hertz, delivered and metered at the voltages and points of delivery specified by the service contract.

Monthly Rate:

Capacity Charge: \$1.82 per kilowatt of billing demand.

Energy Charge: 4.15 mills per kilowatthour for each kilowatthour scheduled and/or delivered, not to exceed the delivery obligation under the electric service contract.

Billing Demand: The billing demand will be the greater of (1) the highest 30-minute integrated demand established during the month up to, but not in excess of,

the delivery obligation under the power sales contract, or (2) the contract rate of delivery.

Billing for Unauthorized Overruns:

For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual firm power and/or energy obligations, such overrun shall be billed at ten (10) times the above rates.

Adjustments:

For Transformer Losses:

If delivery is made at transmission voltage but metered on the low-voltage side of the transformer, the meter readings will be increased two (2) percent to compensate for transformer losses.

For Power Factor:

None. The customer will normally be required to maintain a power factor at the point of delivery of between 95 percent lagging and 95 percent leading.

Schedule PD-T1

UNITED STATES
DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

BOULDER CITY AREA

PARKER-DAVIS PROJECT,
ARIZONA-CALIFORNIA-NEVADA

SCHEDULE OF RATES FOR FIRM TRANSMISSION SERVICE

Effective:

The first day of the first full billing period beginning on or after June 16, 1980.

Available:

In the area served by the Parker-Davis Project.

Applicable:

To firm transmission service customers where power and energy are supplied to the Parker-Davis system at points of interconnection with other systems and transmitted and delivered, less losses, to points of delivery on the Parker-Davis system specified in the service contract.

Character and Conditions of Service:

Transmission service for three-phase alternating current at sixty (60) Hertz, delivered and metered at the voltages and points of delivery specified in the service contract.

Rate:

Transmission Service Charge: \$6.80 per kilowatt per year for each kilowatt contracted for at the point of delivery as specified in the service contract; payable monthly at the rate of \$0.567 per kilowatt.

Adjustments:

For Reactive Power:

None. There shall be no entitlement to transfer of reactive kilovoltamperes at delivery points, except when such transfers may be mutually agreed upon by Contractor and contracting officer or their authorized representatives.

For Losses:

Power and energy losses incurred in connection with the transmission and delivery of power and energy under this rate schedule shall be supplied by the customer in accordance with the service contract.

Schedule PD-T2

UNITED STATES
DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

BOULDER CITY AREA

PARKER-DAVIS PROJECT
ARIZONA-CALIFORNIA-NEVADA

**SCHEDULE OF RATES FOR TRANSMISSION
SERVICE OF COLORADO RIVER STORAGE
(CRSP) POWER AND ENERGY**

Effective:

The first day of the first full billing period beginning on or after June 16, 1980.

Available:

In the area served by the Parker-Davis Project.

Applicable:

To Colorado River Storage Project (CRSP) Southern Division customers where such power and energy are supplied to the Parker-Davis system by CRSP at points of interconnection with the CRSP system for transmission and delivery, less losses, to Southern Division customers at points of delivery on the Parker-Davis system specified in the service contract.

Character and Conditions of Service:

Transmission capacity for three-phase alternating current at sixty (60) Hertz, delivered and metered at the voltages and points of delivery specified in the service contract.

Rate:

Transmission Service Charge: \$3.67 per kilowatt of the maximum allowable rate of delivery made available at each point of delivery during each season as specified in the service contract; payable monthly at the rate of \$0.612 per kilowatt.

Adjustments:

For Reactive Power:

None. There shall be no entitlement to transfer of reactive kilovoltamperes at delivery points, except when such transfers may be mutually agreed upon by Contractor and contracting officer or their authorized representatives.

For Losses:

Power and energy losses incurred in connection with the transmission and delivery of power and energy under this rate schedule shall be supplied by the customer in accordance with the service contract.

Schedule PD-T3

UNITED STATES
DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

BOULDER CITY AREA

PARKER-DAVIS PROJECT,
ARIZONA-CALIFORNIA-NEVADA

**SCHEDULE OF RATES FOR NONFIRM
TRANSMISSION SERVICE**

Effective:

The first day of the first full billing period beginning on or after June 16, 1980.

Available:

In the area served by the Parker-Davis Project.

Applicable:

To nonfirm transmission service customers where power and energy are supplied to the Parker-Davis system at points of interconnection with other systems and transmitted and delivered subject to the availability of transmission capacity, less losses, to points of delivery on the Parker-Davis system specified in the service contract.

Character and Conditions of Service:

Transmission service on an intermittent basis for three-phase alternating current at sixty (60) Hertz, delivered and metered at the voltages and points of delivery specified in the service contract.

Rate:

Transmission Service Charge: 1.3 mills per kilowatt-hour for each kilowatthour scheduled; payable monthly.

Adjustments:

For Reactive Power:

None. There shall be no entitlement to transfer of reactive kilovoltamperes at delivery points, except when such transfers may be mutually agreed upon by

Contractor and contracting officer or their authorized representatives.

For Losses:

Power and energy losses incurred in connection with the transmission and delivery of power and energy under this rate schedule shall be supplied by the customer in accordance with the service contract.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR
RESOURCE APPLICATIONS

In the Matter of:

Southeastern Power Administration—) Rate Order
Cumberland Basin Projects') No. SEPA-8
Power Rates)

ORDER EXTENDING
CONFIRMATION AND APPROVAL
OF POWER RATES ON AN INTERIM BASIS
(May 22, 1980)

Pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act, Public Law 95-91, the functions of the Secretary of the Interior and the Federal Power Commission under Section 5 of the Flood Control Act of 1944, 16 U.S.C. 825s, relating to the Southeastern Power Administration (SEPA) were transferred to and vested in the Secretary of Energy. By delegation Order No. 0204-33, effective January 1, 1979, 43 F.R. 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve and place in effect such rates on an interim basis and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. This Rate Order is issued pursuant to the delegation to the Assistant Secretary.

BACKGROUND

On May 22, 1979, the Assistant Secretary for Resource Applications issued Rate Order No. SEPA-4 confirming and approving on an interim basis, as of July 1, 1978, Wholesale Power Rate Schedules CR-1-D and CR-2-D, applicable to power from the Cumberland Basin Projects, Tennessee and Kentucky. Rate Schedule CR-1-D applies to the Tennessee Valley Authority (TVA) and consists of an Annual Charge paid in monthly increments reduced by credits for power retained and sold to customers outside the TVA area. Rate Schedule CR-2-D applies to

retained peaking power and/or standby power sold to Big Rivers Electric Corporation; Indiana Statewide Rural Electric Cooperative, Incorporated, Hoosier Energy Division; Southern Illinois Power Cooperative; and East Kentucky Power Cooperative and delivered at the Cumberland Projects or TVA interconnection points. These rate schedules were to remain in effect on an interim basis through June 30, 1980, unless such period was extended or until FERC confirmed and approved them or substitute rate schedules on a final basis.

These rate schedules, together with an April 1979 Repayment Study and other supporting data, copies of a transcript of a public meeting and applicable power contracts, were submitted to FERC with the request that the rate schedules be confirmed and approved on a final basis.

DISCUSSION

Because of the extraordinary number of Federal power rate actions submitted for final approval since the issuance of Delegation Order No. 0204-33, FERC has been unable to take action on rate schedules applicable to Cumberland Basin power. It is necessary, therefore, for the Assistant Secretary for Resource Applications to extend interim approval of the Cumberland Basin Rate Schedules for an additional 1-year period.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby extend confirmation and approval on an interim basis, effective July 1, 1980, of attached Rate Schedules CR-1-D and CR-2-D. These rate schedules shall remain in effect on an interim basis through June 30, 1981, unless such period is extended or until the FERC confirms and approves them or substitute rate schedules on a final basis.

Issued at Washington, D.C., this 22nd day of May, 1980.

Ruth M. Davis
Assistant Secretary
Resource Applications

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHEASTERN POWER ADMINISTRATION

Wholesale Power Rate Schedule CR-1-D

Availability:

This rate schedule shall be available to the Tennessee Valley Authority (hereinafter called TVA).

Applicability:

This rate schedule shall be applicable to electric power and energy generated at the Dale Hollow, Center Hill, Wolf Creek Old Hickory, Cheatham, Barkley, J. Percy Priest, and Cordell Hull Projects (all of such projects being hereafter called collectively the "Cumberland Projects") and sold under contract between the Department of Energy and TVA.

Character of Service:

The electric power and accompanying energy sold hereunder will be three-phase alternating current at a frequency of approximately 60 Hertz at the outgoing terminals of the Cumberland Projects' switchyards.

Rates:

The payments to the Department of Energy by TVA hereunder for availability of capacity and deliveries of energy from the Cumberland Projects are estimated to produce over a period of years an average annual payment of \$18,450,000, which amount is hereinafter referred to as the "Basic Annual Charge."

The Basic Annual Charge shall be the applicable annual charge for each year (ending June 30) in which the average unregulated flow of water into Wolf Creek Reservoir as determined hereinafter is between 8,500 and 9,250 c.f.s. To determine the applicable annual charge in other years, the Basic Annual Charge shall be adjusted in accordance with variations in said flow of water as follows: For each 750 c.f.s. or fraction thereof by which said flow of water for the year is greater than 9,250 c.f.s., the applicable annual charge shall be greater by \$680,000; for each 500 c.f.s. or fraction thereof by which said flow of water for the year is less than 8,500 c.f.s., the applicable annual charge shall be less by \$750,000; provided, that the applicable annual charge for any year shall be not less than \$15,450,000 nor more than \$21,170,000.

Unless otherwise mutually agreed, the annual unregulated flow of water into the Wolf Creek Reservoir will be established from a consideration of the unadjusted discharge registered at Rowena gauging station as determined by the U.S. Geological Survey, adjusted for changes in storage at all reservoirs upstream from said station, in accordance with capacity ratings by the owners thereof, and for other possible factors which may be mutually agreed upon by the parties.

TVA shall pay the applicable annual charge to Energy in monthly installments as follows:

A. For each of the months July through December, the monthly installment payment shall be \$1,210,000.

B. For the month of January and for each succeeding month through June, the installment payment for each month shall be the amount computed for that month as follows:

1. The estimated applicable annual charge will first be computed using an estimated average flow for the year determined by combining the inflow from the beginning

of the fiscal year through the month for which the installment is being computed with the minimum probable inflow for the remainder of the fiscal year as listed in Table I below opposite the month for which said payment is being computed.

2. The installment payment will then be determined by taking the difference between the estimated applicable annual charge for the fiscal year as determined under 1. and the total of the installment payments for the preceding months in that fiscal year and multiplying said difference by the percentage listed in Table II opposite the month for which the installment payment is being computed.

Month	Table I (Second-Foot Days)	Table II (Percentage)
January	800,000	20
February	700,000	25
March	290,000	30
April	50,000	40
May	7,800	50
June	0	100

C. In the event that the total of the monthly installment payments for any fiscal year exceeds the applicable annual charge for that fiscal year, the excess shall be credited against the monthly installment payments for the succeeding fiscal year.

Credits for Retained Power:

The applicable annual charge shall be adjusted as follows to compensate for the retention of Peaking Power, Standby Power, and "special" emergency Standby Power and the transfer of retained power and energy for sale by the Administrator of Southeastern Power Administration to Other Customers. For each Supply Year, beginning November 1, the applicable charges shall be reduced by:

a. \$17.38 per kW of Peaking Power Base Amount retained by Administrator.

b. \$4.86 per kW of the Contract Standby Demand of the Administrator's first Other Customer, plus \$3.24 per kW of the sum of the Contract Standby Demands of the second and third Other Customers. For purposes hereof, such "first" Other Customer shall be the one with the largest Contract Standby Demand.

c. 6.4 cents per calendar day (or fraction thereof) per kW of emergency Standby Power used in November, April, May, June, September, and October of each Supply Year, and 9.9 cents per calendar day (or fraction thereof) per kW of the emergency Standby Power used during any other period of the years.

d. 3.26 mills per kWh of energy associated with the Peaking Power Base Amount and of the energy scheduled with the use of maintenance Standby Power.

e. 5.32 mills per kWh of energy scheduled with the use of emergency Standby Power.

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHEASTERN POWER ADMINISTRATION

Wholesale Power Rate Schedule CR-2-D

f. \$25.50 per kilowatt of the maximum amount, if any, by which the capacity used by the Other Customers exceeds the amount of the Cumberland Capacity to which the Administrator is entitled. For purposes of this subsection, the Administrator shall be entitled at any time to the sum of the following:

(1) The total of Peaking Power retained by the Administrator for use at that time by all of the Other Customers, and

(2) If the Administrator at that time is delivering Standby Power to any Other Customer, the Contract Standby Demand of that Customer and any amount that is being retained as "special" emergency Standby Power at that time.

Notwithstanding the foregoing, insofar as such excess consists of excess emergency Standby Power takings, the reduction provided for in this subsection f. shall not apply to the first 100 MW for the first 24 hours of the first four occasions of the emergency excess takings in any Supply Year caused by outages of generating units of the Administrator's Other Customers occurring simultaneously with scheduled outages or other emergency outages.

g. 5.32 mills per kWh of the energy taken in any hour excess of the amount of energy to which the Administrator is entitled.

During each month of a Supply Year, the monthly installments due shall be reduced by one-twelfth of the sum of the amounts of the annual reductions computed under a. and b. above, and by the sum of the amounts of the reductions computed under c, d, e, f, and g above for the month.

Service Interruption:

When delivery of power to TVA is interrupted or reduced due to failure of facilities at any of the Cumberland Projects and whenever such interruption or reduction results in a loss for a continuous period of more than 31 days of installed capacity (name plate) in excess of 50 megawatts or loss of an entire project, the payments to be made by TVA for the months in which such interruption affects the delivery of power shall be adjusted; provided, however, that no monthly bill will be adjusted until there is a net cumulative monetary credit due TVA. Monthly adjustments will be determined as follows:

a. Adjustments for changes in energy deliveries will be determined by multiplying the change in energy determined by the Administrator to have resulted from the interruption or reduction by 3.16 mills per kilowatt-hour.

b. Adjustments for installed capacity losses for each month in which the interruption or reduction occurs for more than half the hours in the month will be determined by multiplying the name plate capacity determined by the Administrator to have been lost as a result of the interruption or the reduction by \$0.90 per kilowatt.

Availability:

This rate schedule shall be available to the Big Rivers Electric Corporation; Indiana Statewide Rural Electric Cooperative, Incorporated, Hoosier Energy Division; Southern Illinois Power Cooperative; and East Kentucky Power Cooperative (hereinafter individually called Customer; collectively, Customers).

Applicability:

This rate schedule shall be applicable to Peaking Power, Standby Power, and "special" emergency Standby Power, together with accompanying energy generated at the Dale Hollow, Center Hill, Wolf Creek, Cheatham, Old Hickory, Barkley, J. Percy Priest, and Cordell Hull Projects (all of such projects being hereinafter called collectively the "Cumberland Projects") and sold in wholesale quantities.

Character of Service:

The electric capacity and energy supplied hereunder will be three-phase alternating current at a frequency of 60 cycles per second and shall be delivered at nominal voltages of 13,800 volts and 161,000 volts to the transmission systems of the Big Rivers Electric Corporation and the East Kentucky Power Cooperative. The points of delivery to the Big Rivers EC transmission system will be one at 13,800 volts and two at 161,000 volts in the vicinity of the Barkley dam power plant and another point of delivery at 161,000 volts from the TVA transmission system in the vicinity of Paradise, Kentucky. The point of delivery for East Kentucky PC will be at the 161,000 volt bus of the Wolf Creek power plant. Other points of delivery may be as agreed upon.

Monthly Rate:

The monthly rate for capacity and energy sold under this rate schedule shall be:

Demand Charge:

\$16.80 per Supply Year for each kilowatt of the Contract Peaking Demand, payable \$1.40 per billing month.

\$4.26 per Supply Year for each kilowatt of the Contract Standby Demand, payable in equal monthly installment payments of one-twelfth of the annual charge.

\$0.064 per calendar day (or fraction thereof) per kW of Standby Power delivered for emergency purposes in November, April, May, June, September, and October of each Supply Year, and \$0.099 per calendar day (or fraction thereof) per kilowatt of the Standby Power delivered for emergency purposes during any other period of the year.

July 1, 1978

Whenever a Customer's use of standby capacity for emergency outage is reduced during a day because of emergency outage of another or other Customers, the Customer first using emergency standby capacity shall pay the daily use charge to the extent of his maximum usage. Other Customers shall pay a daily use charge that day only to the extent that they cause a higher maximum to be established.

A Supply Year is a year beginning November 1.

Energy Charge:

4.20 mills per kilowatt-hour for all Peaking Energy.

3.26 mills per kilowatt-hour for all maintenance Standby Energy.

5.32 mills per kilowatt-hour for all emergency Standby Energy.

"Special" Emergency Standby Power:

"Special" emergency Standby Power from the Cumberland capacity can be made available by the Government to any particular Customer for periods of not less than one week. Any such amounts of power so made available and bought by said Customer shall be at rates as agreed upon by the operating representatives of the parties prior to commencing delivery.

Billing Month:

The billing month of power sold under this schedule shall end at 12:00 midnight on the last day of each calendar month.

Conditions of Service:

The Standby Capacity and Peaking Capacity and the associated Standby Energy and Peaking Energy sold to Customers under this rate schedule shall come exclusively from capacity and energy available from the Cumberland Projects and retained by the Administrator. Standby Capacity shall be used by Customers only to replace loss of generation on their systems because of maintenance and/or emergency outages of their generating equipment. Maintenance outages shall be a matter of coordination between the Government and the Customers.

The rates and charges for Standby Capacity purchased are predicated upon the purchase of such capacity by three customers.

Each customer is prohibited from using in any supply year any Standby Capacity and Peaking Capacity in excess of the capacity to which it is entitled. Should the power used by any individual Customer exceed the capacity to which it is entitled in any sixty (60) consecutive minute period in any Supply Year, such Customer shall pay the Government \$25.50 per kilowatt of the largest such excess occurring during that year through the current billing period. Notwithstanding the foregoing, insofar as such excess consists of emergency Standby Power takings by a Customer caused by outages of generating units of any of the three Customers occurring simultaneously with scheduled outages or other emer-

gency outages, the payment provided herein shall not apply to the first 100 MW for the first 24 hours of the first four occasions of the emergency takings in any Supply Year; provided, that the first four occasions provided herein are a total for the three Customers and will be applied to the first four excess emergency takings by the Customers in the order of their occurrence. Each Customer shall also pay the Government 5.32 mills per kilowatt-hour for Standby Energy taken in any hour in excess of the amount of energy to which such Customer is entitled.

The terminal equipment required for delivery of power at the Barkley switchyard will be furnished by the Government, and the terminal equipment required at any other points of delivery agreed upon with Big Rivers will be furnished by Big Rivers. The costs of the terminal equipment required for delivery of power at the Wolf Creek power plant to East Kentucky shall be borne by the Government.

Unless otherwise agreed, the interconnected electric systems of the Customers and the system of TVA shall be operated in parallel and such Customers shall not interconnect their respective systems with other power systems that are normally operated in parallel with TVA's system.

Service Interruption:

When capacity made available and sold under this rate schedule is reduced or interrupted for sixty (60) minutes or longer and such reduction or interruption is not due to conditions on the individual Customer's system, (a) the monthly demand charge for Standby Capacity for the billing month shall be reduced for billing purposes for each hour (the nearest number of whole hours) that such capacity is reduced or interrupted, by an amount equal to one-twelfth of the annual charge divided by the number of hours in the billing month times the reduction, in kilowatts, of such capacity, (b) the monthly charge for Peaking Capacity for the billing month shall be reduced for billing purposes, for each hour (the nearest number of whole hours) that such capacity is reduced or interrupted, by an amount equal to \$1.40 divided by the number of hours in the billing month times the reduction, in kilowatts, of such capacity, and (c) the amount of Peaking Energy which such Customer had scheduled but did not receive on the day or days of interruption may be rescheduled and taken by such Customer not later than the close of the then current Supply Year.

July 1, 1978

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR
RESOURCE APPLICATIONS

In the Matter of:
Southwestern Power Administration—) Rate Order

**ORDER CONFIRMING AND APPROVING
EXTENSION OF POWER RATE
ON AN INTERIM BASIS
(June 6, 1980)**

Pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act, Public Law 95-91, the functions of the Secretary of the Interior and the Federal Power Commission under Section 5 of the Flood Control Act of 1944, 16 U.S.C. 825s, relating to the Southwestern Power Administration (SWPA) were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 FR 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve, and place in effect such rates on an interim basis, and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. This rate order is issued pursuant to the delegation to the Assistant Secretary.

BACKGROUND

All power from the isolated Narrows Dam is currently purchased by Tex-La Electric Cooperative, Inc. (Tex-La), an organization of distribution cooperatives in East Texas and Louisiana financed by the Rural Electrification Administration. The power is delivered at the dam and sold to Tex-La under the rate provided in Contract No. 14-02-0001-921, as approved by the Federal Power Commission (FPC) August 3, 1976, through Docket No. E-6943. As set forth in the FPC action, the current contract rate is in effect only through June 30, 1980, a term shorter than established in the Tex-La Contract in which changes in rates are limited to once every five years. The five-year period outlined in the Tex-La Contract provides for the rate to be in effect through August 2, 1981, causing inconsistency between the effective periods outlined in the FPC action and the Tex-La Contract.

DISCUSSION

The Tex-La rate under Contract No. 14-02-0001-921 is formulated to produce annual revenue of \$556,000 based on results of the May 1975 Average Rate and Repayment Study which reflected the need for \$91,000 of additional annual revenue to accomplish the required level of repayment. During the summer of 1980, revised studies are to be completed to determine the level of revenue that is adequate to satisfy the cost recovery criteria outlined in Section 5 of the Flood Control Act of 1944 and Order No.

RA 6120.2. If the results of the studies indicate that additional revenue is required to meet the cost recovery criteria, public comment will be invited. Therefore, an extension of the power rate on an interim basis through August 2, 1981, is necessary not only to uphold the terms of the Tex-La Contract, but to allow time to develop studies necessary for review of the present power rate and to undertake a public participation process in the event the rate requires adjustment.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, effective July 1, 1980, an extension of the existing rate under Contract No. 14-02-0001-921 for the sale of power from the Narrows Dam to Tex-La Electric Cooperative, Inc. This rate shall remain in effect on an interim basis through August 2, 1981, unless the period is again extended or until the FERC confirms and approves this or a substitute rate on a final basis.

Issued in Washington, D.C., this 6th day of June, 1980.

Ruth M. Davis
Assistant Secretary
Resource Applications

**UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR
RESOURCE APPLICATIONS**

In the Matter of:

Southwestern Power Administration—) Rate Order
Schedule TDC (Revised)) No. SWPA-6

**ORDER EXTENDING CONFIRMATION
AND APPROVAL OF TRANSMISSION RATES
ON AN INTERIM BASIS
(Issued July 1, 1980)**

Pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act, Public Law 95-91, the functions of the Secretary of the Interior and the Federal Power Commission under Section 5 of the Flood Control Act of 1944, 16 U.S.C. 825s, for the Southwestern Power Administration (SWPA) were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 FR 60636 (December 28, 1978) the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, to confirm, approve, and place in effect such rates on an interim basis, and delegated to the Federal Energy Regulatory Commission

(FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. This rate order is issued pursuant to the delegation to the Assistant Secretary.

BACKGROUND

Existing Rates

On January 23, 1973, the Assistant Secretary for Power and Water (Water and Power-Ed.) Resources, U.S. Department of the Interior approved SWPA's Schedule of transmission and/or displacement charges (Schedule TDC) for transmission of non-federal power and energy over the SWPA transmission system for a period ending January 23, 1976. No regulatory authority approval was required by statute.

On June 29, 1973, by the approval of the Assistant Secretary, Energy and Minerals, U.S. Department of the Interior, Schedule TDC was amended to provide that surplus capacity in SWPA transmission facilities could be made available to other than SWPA customers. No regulatory authority approval was required and the Assistant Secretary's approval was extended until June 30, 1976. Schedule TDC (Amended) was revised and later approved by the Assistant Secretary, Energy and Minerals, U.S. Department of the Interior, on August 2, 1976, for a period ending June 30, 1979. Schedule TDC (Revised) maintained the same pricing as the original Schedule TDC with provision to correct certain inequities in the adjustment for power factor.

On June 18, 1979, the Assistant Secretary for Resource Applications, U.S. Department of Energy approved the extension of the existing Schedule TDC (Revised), on an interim basis, effective July 1, 1979, for a period ending June 30, 1980, and submitted the extension to the FERC for final confirmation and approval.

DISCUSSION

Eleven customers are presently being billed for transmission service under Schedule TDC (Revised): Ark-Mo Power Company; Public Service Company of Oklahoma; Associated Electric Cooperative; Western Farmers Electric Cooperative; Kennett, Missouri; New Madrid, Missouri; Paragould, Arkansas; Piggott, Arkansas; Poplar Bluff, Missouri; Sikeston, Missouri; and Grand River Dam Authority. Revenue under this rate schedule is estimated to be about 1% of the total expected integrated system gross revenue.

An order extending confirmation and approval of Schedule TDC (Revised) on an interim basis is necessary for SWPA to receive revenues from billings for transmission service performed after June 30, 1980, to allow time to complete a detailed study of the rates for the future and to provide opportunity for public participation and comments on any proposed revision.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby extend confirmation and approval, on an interim basis, effective July 1, 1980, of Schedule TDC (Revised) for transmission and/or displacement of nonfederal power and energy over the system of SWPA. This rate shall remain in effect on an interim basis, through December 31, 1980, unless such period is further extended or until the FERC confirms and approves this rate or a substitute rate on a final basis.

Issued at Washington, D.C., this 1st day of July, 1980.

Ruth M. Davis
Assistant Secretary
Resource Applications

UNITED STATES OF AMERICA DEPARTMENT OF ENERGY ASSISTANT SECRETARY FOR RESOURCE APPLICATIONS

In the Matter of:

Bonneville Power Administration—	) Rate Order
Pacific Northwest Coordination	) BPA-3
Agreement, Section 14 Charges	

ORDER CONFIRMING AND PLACING INTO EFFECT UPON APPROVAL BY THE FERC INCREASED POWER AND TRANSMISSION RATES (July 1, 1980)

The functions of the Secretary of the Interior and the Federal Power Commission under the Bonneville Project Act, 16 U.S.C. 832, the Federal Columbia River Transmission System Act, 16 U.S.C. 838, and other statutes relating to the Bonneville Power Administration were transferred to and vested in the Secretary of Energy pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act, Public Law 95-91. By Delegation Order No. 0204-33, effective January 1, 1979, 43 F.R. 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve, and place in effect such rates on an interim basis. Also under this delegation order, the Secretary of Energy delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. This rate order is issued pursuant to the delegation to the Assistant Secretary.

BACKGROUND

Pacific Northwest Coordination Agreement

Bonneville Power Administration (Bonneville) is a party to the Pacific Northwest Coordination Agreement (Agreement) which was executed September 15, 1964, by 17 entities in the Pacific Northwest including the United States of America (Bonneville, the Corps of Engineers and the "United States Entity"), three municipalities, six public utility districts of the State of Washington, and six privately owned utilities.

The Agreement provides for the implementation of two basic objectives. The major objective is to secure optimum Firm Load Carrying Capability (Sections 2(p), 6(c)(4), 6(i) and 6(j)) for the Coordinated System (Section 2(f), without regard to the desires of the individual parties. In the planning sections of the Agreement (Sections 6, 7, and 8), the various resources of all parties are planned to operate to meet the Coordinated System load, as if such resources were under single ownership. The draft of all storage from reservoirs is planned so that maximum energy generation during a recurrence of critical water conditions would result. (See Section 6(b)(1).)

The second basic objective implemented by the Agreement is to make the owners of all projects affected by headwater seasonal storage, whether downstream from or at the site of such storage, equal with respect to the operation of such storage.

The inevitable imbalances between loads and resources on individual systems resulting from the complex firm power optimizing techniques established by the Agreement are handled through a series of energy interchanges designed to guarantee each participant its ability to meet firm loads equal to its firm capability. Under the streamflow conditions on which firm capability is based, all interchange energy delivered will be returned. However, since this streamflow pattern is extremely unlikely to be repeated exactly, based on a number of circumstances, the parties seldom are able to "zero out" balances of interchange energy. As a result, charges must be established for energy and capacity interchange imbalances. Such charges are set forth in Subsections 14(a) and 14(c). In addition to those charges the parties to the Agreement are compensated for providing a number of other services provided for in the Agreement, such as storage of energy, 14(e) and (g); transmission, 14(f); transfer to avoid spills, 14(h); charges for return of interchange energy onpeak, 14(b); and acceptance and retention of holding interchange energy, 14(d). It is these charges which are the subject of this Order.

Revised Charges

The revised charges under Section 14 of the Agreement are designed to more accurately reflect the costs and values of the energy, capacity, wheeling, and storage services which are provided under the agreement to avoid the creation of any artificial incentives for the partici-

ants in the agreement to unnecessarily use the energy, capacity, or storage facilities of other participants.

The rates and charges approved pursuant to this Order have been negotiated among the 16 parties to the Agreement and are subject to approval by the FERC for jurisdictional utilities and pursuant to Section 14(j) of the unamended agreement.

DISCUSSION

Need for Rate Increase

Most Coordination Agreement rates are subject to negotiation only once every 5 years under the existing agreement. Transmission charges under Section 14(f) are subject to revision annually under the proposed amendments. The charges under Section 14 of the agreement were last amended in 1975. Since then, the cost of providing all services under the Agreement has increased to all parties to the agreement. As a result, the existing charges under Section 14 of the Agreement are inadequate to thoroughly compensate parties for services provided under the other sections of the agreement. Furthermore, the existing inadequate rates create improper incentives to obtain services under the agreement which could cause burdens to provider systems not anticipated at the time the agreement was executed.

Nature of Settlement

The 16 parties to the Agreement have agreed on charges for providing energy, capacity, transmission and storage services under the Agreement. Given that the parties have widely varying costs for provision of such services, the rates and charges proposed to the FERC are of necessity a compromise. Because the Agreement is necessary to the optimization of the firm load carrying capability of Bonneville, the Agreement is of sufficient benefit to Bonneville to warrant the approval of the revised charges. Furthermore since the charges very closely resemble those confirmed and approved by me by Order BPA-2 on December 3, 1979 (44 F.R. 70517), I find that the charges under Section 14 of the agreement are the lowest possible consistent with sound business principles having regard to the recovery of the cost of producing and transmitting the electric power, including amortization of the capital investment allocated to power, over a reasonable period of years.

ORDER

Based upon the foregoing, plus the materials submitted to the FERC in support of these charges by Bonneville and the other parties to the agreement, I hereby confirm and approve, effective upon the later of July 1, 1980, or the date of approval by the FERC of the proposed settlement agreement, the attached amendment to charges contained in Section 14 of the Pacific Northwest Coordination Agreement for application by Bonneville.

Issued in Washington, D.C. this 1st day of July 1980.

Ruth M. Davis
Assistant Secretary
Resource Applications

AMENDATORY AGREEMENT NO. 2

PACIFIC NORTHWEST COORDINATION AGREEMENT

SEPTEMBER, 1964

THIS AGREEMENT, entered into as of the _____ day of May, 1980, by and between the UNITED STATES OF AMERICA, acting by and through the Administrator, BONNEVILLE POWER ADMINISTRATION of the DEPARTMENT OF THE INTERIOR (now the DEPARTMENT OF ENERGY) (hereinafter called the "Administrator") and the DIVISION ENGINEER, North Pacific Division, Corps of Engineers, Department of the Army (hereinafter called the "Division Engineer"); the UNITED STATES ENTITY designated pursuant to Article XIV of the Treaty; the CITY OF EUGENE, OREGON, a municipal corporation of the State of Oregon; the CITY OF SEATTLE, WASHINGTON, a municipal corporation of the State of Washington; the CITY OF TACOMA, WASHINGTON, a municipal corporation of the State of Washington; PUBLIC UTILITY DISTRICT NO. 2 OF GRANT COUNTY, WASHINGTON, a municipal corporation of the State of Washington; PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY, WASHINGTON, a municipal corporation of the State of Washington; PUBLIC UTILITY DISTRICT NO. 1 OF PEND OREILLE COUNTY, WASHINGTON, a municipal corporation of the State of Washington; PUBLIC UTILITY DISTRICT NO. 1 OF DOUGLAS COUNTY, WASHINGTON, a municipal corporation of the State of Washington; PUBLIC UTILITY DISTRICT NO. 1 OF COWLITZ COUNTY, WASHINGTON, a municipal corporation of the State of Washington; PUGET SOUND POWER & LIGHT COMPANY, a corporation; PORTLAND GENERAL ELECTRIC COMPANY, a corporation; PACIFIC POWER & LIGHT COMPANY, a corporation; THE WASHINGTON WATER POWER COMPANY, a corporation; MONTANA POWER COMPANY, a corporation; and COLOCKUM TRANSMISSION COMPANY, INC., a corporation;

Section 14 of the Pacific Northwest Coordination Agreement executed as of September 15, 1964, as amended by Amendatory Agreement No. 1 effective July 1, 1976, shall be amended to read as follows:

Section 14. *Other Charges.* The charges listed in this section shall be applicable to exchanges, transfers and services performed under this Agreement.

(a) *Interchange Energy Imbalances*

Interchange Energy imbalances between Systems

referred to in paragraph 9(e)(3) shall be paid at the following rates:

(1) When supplied from hydroelectric sources, six (6.0) mills per kilowatt hour.

(2) When supplied from thermal electric sources of the delivering Party or purchases under firm contract, three (3.0) mills per kilowatt hour plus incremental costs, or six (6.0) mills per kilowatt hour, whichever is greater. Incremental costs shall include but not be limited to fuel costs, special maintenance costs and starting and shutdown costs of thermal electric plants, but shall not include fixed charges or other costs which would have been incurred by the supplying System if the transfer had not been made

(3) When supplied from previously received Interchange Energy, the rate per kilowatt hour charged to the supplying system for such energy under this subsection 14(a). Energy supplied as previously received Interchange Energy shall be limited to Interchange Energy received by the supplying System since the last settlement of Interchange Energy imbalances made pursuant to paragraph 9(e)(3). If the supplying System has previously received Interchange Energy at more than one rate and is delivering from such previously received Interchange Energy, it shall designate which of such energy it is delivering. Such received Interchange Energy shall be thermal Interchange Energy for the purpose of determining priorities pursuant to subsections 9(f) and 9(g). Delivery of such received Interchange Energy shall constitute an assignment of the rights and obligations of the supplying System relating to such energy, with respect to the original supplying System under this agreement, to the receiving System, as if the original delivery of such energy had been made directly to the receiving System. If the supplying System previously paid interim cash advances on account for such energy, pursuant to paragraph 9(e)(6), the receiving system shall pay the equivalent cash advances to the supplying System at the time of delivery. All Systems shall be notified promptly of the change of accounts by the supplying System.

(b) *Interchange Energy Service Charge.*

Any party returning Interchange Energy under subsection 9(e) shall pay to the original supplying party a service charge at the following rates:

(1) No charge for energy returned during the period Monday through Saturday, 7:00 a.m. through 10:00 p.m.

(2) Two (2.0) mills per kilowatt hour when returned at other hours, unless such energy was supplied during such other hours, or its return during such other hours was requested, in either of which events there shall be no charge.

(c) *Interchange Capacity Imbalances.*

Except for Interchange Capacity delivered under subparagraph 9(c)(2)(B), which shall be at no cost, Interchange Capacity imbalances between Systems resulting from Capacity Interchanges provided for in paragraph 9(c)(2) shall be paid for at the end of each Contract Year at the rate of thirty-eight cents (\$0.38) per kilowatt week.

(d) *Holding Interchange Energy Service Charge*

Any party accepting the return of Holding Interchange Energy under paragraph 9(d)(4) shall pay to the importing party a service charge of two (2.0) mills per kilowatt hour.

When Holding Interchange Energy is delivered by a third party during the period Monday through Saturday, 7:00 a.m. through 10:00 p.m., and said energy was delivered to the third party at other hours, the original exporting party shall pay to the third party a service charge of two (2.0) mills per kilowatt hour whenever such service is required for the original delivery or subsequent return of Holding Interchange Energy.

(e) *Stored Energy Service Charge.*

Energy returned from storage pursuant to paragraph 9(j)(1) shall be paid for by the party requesting the return of such energy at the following rates:

(1) Three (3.0) mills per kilowatt hour when returned during the period Monday through Saturday, 7:00 a.m. through 10:00 p.m.

(2) One (1.0) mill per kilowatt hour when returned at other hours.

(f) *Transmission Service Charges.*

Transmission capacity provided pursuant to subsection 10(a) by a party for transactions where it acts solely as a transferor shall in the absence of a separate agreement for such transmission between the parties involved, be paid for in accordance with the following rates and by the following parties:

(1) Interchange Energy delivered or returned—one (1.0) mill per kilowatt hour, paid by the original receiving System.

(2) Holding Interchange Energy delivered or returned pursuant to subsection 9(d) and stored energy delivered or returned pursuant to subsection 9(j)—one (1.0) mill per kilowatt hour on each transfer, paid by the party delivering such energy or requesting the return of such energy; provided, however, that no charge shall be made, or if a charge has been made a rebate will be given, upon receipt by the transferring party of notice that energy delivered as Holding Interchange Energy or stored energy has been spilled.

(3) In Lieu Energy—no charge, except when the priorities of subsection 9(i) are invoked by the supplying or receiving System to require the transferor to provide such transmission, in which case the party invoking the priority shall pay one (1.0) mill per kilowatt hour.

(4) Provisional Energy delivered or replaced

pursuant to subparagraph 9(n)(1)(B)—one (1.0) mill per kilowatt hour paid by the Reservoir Party.

(5) Energy deliveries associated with the delivery of Interchange Capacity pursuant to paragraph 9(c)(2) or energy deliveries associated with the delivery of emergency capacity due to Forced Outages pursuant to paragraph 9(q)(2), or the return of such energy—one (1.0) mill per kilowatt hour, paid by the original receiving System.

(g) *Special Storage Arrangements.*

Unless otherwise agreed to by the parties to the storage arrangement, energy returned from storage pursuant to paragraph 9(j)(2) shall be paid for by the party requesting the return of such energy at the following rates:

(1) Three (3.0) mills per kilowatt hour when returned during the period Monday through Saturday, 7:00 a.m. through 10:00 p.m.

(2) One (1.0) mill per kilowatt hour when returned at other hours.

(h) *Transfers to Avoid Spill.*

Notwithstanding the foregoing subsections of this section there shall be no charge for the transfer of stored energy from the reservoir of one party to the reservoir of another party in order to avoid probable spill; provided however, that if such energy is returned to the original supplying system and if it is determined at the end of the Drawdown Period, on the basis of such System's actual reservoir contents, that a part or all of such energy has been used by such supplying System, the energy so used shall be paid for by such supplying System to the party returning such energy at the rate of two (2.0) mills per kilowatt hour.

(i) *Billing.*

Other than as provided in paragraph 9(e)(6) and in subsection 13(d), parties shall be billed monthly and shall make payment within 20 days after billing.

(j) *Changes in Charges.*

Commencing on July 1, 1981, and each year thereafter, the parties shall, upon notice given by any party prior to July 1 specifying desired changes, review the charges in subsection (f) above. Commencing on July 1, 1984, and each fifth year thereafter the parties shall, upon notice given by any party prior to such July 1 specifying desired changes, review the remaining charges in effect under this section. If the parties fail to agree on revised charges, the parties hereto who are subject to the jurisdiction of the Federal Energy Regulatory Commission with respect to such charges shall submit the matter on or before the following January 1 to the Commission for determination of charges to be made by such parties; and the other parties hereto agree, insofar as they may lawfully do so, that the charges to be made by them shall not be in excess of the charges so fixed by the Commission, provided that any of such

other parties may, but shall not be obligated to, reduce any charge in effect at the time of such submission. Each party hereby gives its irrevocable consent to the intervention by all other parties in such proceeding before the Commission. The charges agreed upon or as finally determined by the Commission shall become effective at the beginning of the Contract Year following such agreement or determination.

This Amendment shall be effective as of the later to occur of July 1, 1980, or the effective date of the Order of the Federal Energy Regulatory Commission approving the Settlement Agreement pursuant to which this Amendment has been executed and the revised charges set forth herein shall become effective as of such date.

Except as expressly amended hereby, all the terms and conditions of the Pacific Northwest Coordination Agreement shall remain in full force and effect. This Amendment is to be executed in counterparts and shall be binding when counterparts signed by all parties have been deposited with the Secretary of the Coordination Contract Committee.

(SIGNATURES OF THE PARTIES)

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY
FOR RESOURCE APPLICATIONS

In the Matter of:

Southeastern Power Administration—) Rate Order
Georgia-Alabama Projects') No SEPA-9
Power Rates)

ORDER EXTENDING CONFIRMATION
AND APPROVAL OF POWER RATES
ON AN INTERIM BASIS
(September 12, 1980)

Pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act, Public Law 95-91, the functions of the Secretary of the Interior and the Federal Power Commission under Section 5 of the Flood Control Act of 1944, 16 U.S.C. 825s, relating to the Southeastern Power Administration (SEPA) were transferred to and vested in the Secretary of Energy. By delegation Order No. 0204-33, effective January 1, 1979, 43 F.R. 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve and place in effect such rates on an interim basis and delegated to the Federal Energy

Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. This Rate Order is issued pursuant to the delegation to the Assistant Secretary.

BACKGROUND

On July 31, 1979, the Assistant Secretary for Resource Applications issued Rate Order No. SEPA-5 confirming and approving on an interim basis, effective October 1, 1979, Wholesale Power Rate Schedules GAMF-1-B, GAMF-2-B, ALA-1-B, MISS-1-B, SC-1-B, SC-2-B, CAR-1-B and CAR-2-B applicable to power from the Georgia-Alabama Projects. These rate schedules were to remain in effect on an interim basis through September 30, 1980, unless such period was extended or until FERC confirmed and approved them or substitute rate schedules on a final basis. The rate schedules, together with a March 1979 Repayment Study and other supporting data, copies of a transcript of a Public Comment Forum and applicable power contracts, were submitted to FERC with the request that the rate schedules be confirmed and approved on a final basis.

DISCUSSION

Because of the extraordinary number of Federal power rate actions submitted for final approval since the issuance of Delegation Order No. 0204-33, FERC has been unable to take action on rate schedules applicable to Georgia-Alabama Projects' power. It is necessary, therefore, for the Assistant Secretary for Resource Applications to extend interim approval of the Georgia-Alabama Projects' Power Rate Schedules for an additional 1-year period.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby extend confirmation and approval on an interim basis, effective October 1, 1980, of attached Rate Schedules GAMF-1-B, GAMF-2-B, ALA-1-B, MISS-1-B, SC-1-B, SC-2-B, CAR-1-B and CAR-2-B. These rate schedules shall remain in effect on an interim basis through September 30, 1981, unless such period is extended or until the FERC confirms and approves them or substitute rate schedules on a final basis.

Issued at Washington, D.C., this 12th day of September 1980.

Ruth M. Davis
Assistant Secretary
Resource Applications

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHEASTERN POWER ADMINISTRATION

Wholesale Power Rate Schedule GAMF-1-B

Availability:

This rate schedule shall be available to public bodies and cooperatives (any one of which is hereinafter called the Customer) in Georgia, Alabama, southeastern Mississippi, and panhandle Florida owning distribution systems, to whom power may be wheeled pursuant to contracts between the Government and, respectively, the Georgia Power Company, Alabama Power Company, Mississippi Power Company, and Gulf Power Company (any one of which is hereinafter called the Company).

Applicability

This rate schedule shall be applicable to the sale at wholesale of power and accompanying energy generated at the Allatoona, Buford, Clark Hill, Walter F. George, Hartwell, Millers Ferry, West Point, Jones Bluff, and Carters Projects and sold under appropriate contracts between the Government and the Customer and to any deficiency energy purchased by the Government from the Companies.

Character of Service:

The electric capacity and energy supplied hereunder will be three-phase alternating current at a nominal frequency of 60 Hertz delivered at the delivery points of the Customer on the Company's transmission and distribution system. The voltage of delivery will be maintained within the limits established by the state regulatory commission.

Monthly Rate:

The monthly rate for capacity and energy sold under this rate schedule shall be:

Demand Charge:

\$1.02 per kilowatt of total contract demand.

Energy Charge:

3.65 mills per kilowatt-hour.

Contract Demand:

The contract demand is the amount of capacity in kilowatts stated in the contract which the Government is obligated to supply and the Customer is entitled to receive.

Energy to be Furnished by the Government:

The Government will sell to the Customer and the Customer will purchase from the Government energy each billing month equivalent to an annual energy quantity specified by contract and prorated on an equal daily amount throughout the year. The Customer's contract demand and accompanying energy will be allocated proportionately to its individual delivery points served from the Company's system.

Billing Month:

The billing month for power sold under this schedule shall end at 12:00 midnight on the last day of each calendar month.

Conditions of Service:

The Customer shall at its own expense provide, install, and maintain on its side of each delivery point the equipment necessary to protect and control its own system. In so doing, the installation, adjustment, and setting of all such control and protective equipment at or near the point of delivery shall be coordinated with that which is installed by and at the expense of the Company on its side of the delivery point.

Service interruption:

When energy delivery to the Customer's system for the account of the Government is reduced or interrupted for 1 hour or longer, and such reduction or interruption is not due to conditions on the Customer's system, the demand charge for the month shall be appropriately reduced.

October 1, 1979

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHEASTERN POWER ADMINISTRATION

Wholesale Power Rate Schedule GAMF-2-B

Availability:

This rate schedule shall be available to the Georgia Power Company, the Alabama Power Company, the Mississippi Power Company, and the Gulf Power Company (any one of which is hereinafter called the Company).

Applicability:

This rate schedule shall be applicable to electric capacity available from the Allatoona, Buford, Clark Hill, Walter F. George, Hartwell, Millers Ferry, West Point, Jones Bluff, and Carters Projects (hereinafter called the Projects) and sold under contract between the Government and the Company.

Character of Service:

Electric capacity and energy delivered to the Company will be three-phase alternating current at a nominal frequency of 60 Hertz and will be delivered at mutually agreeable points in the vicinity of the Projects' Power stations at approximately 115,000 volts, except that delivery from the Hartwell and Carters Projects will be at approximately 230,000 volts or at points of interconnection between the Companies.

Monthly Rate:

The monthly rate for capacity sold under this rate schedule shall be:

Demand Charge:

\$1.02 per kilowatt per billing for monthly dependable capacity made available to the Company for its own use.

Monthly dependable capacity is the monthly capacity, specified by contract, which based on past water records would be available for scheduling by the Companies within the energy limitations also specified by contract, except during the worst water period of record and except for a few minor short-term reductions under flood conditions.

Billing Month:

The billing month for power sold under this schedule shall end at 12:00 midnight on the last day of each calendar month.

Power Factor:

The Company shall take capacity and energy from the Government at such power factor as will best serve the Company's system from time to time, provided that the Company shall not impose a power factor of less than .85 lagging on the Government's facilities which requires operation contrary to good operating practice or results in overload or impairment of such facilities or unreasonably interferes with the delivery of capacity and energy by the Government to the Company and to its other customers.

Service Interruption:

When delivery of capacity to the Company is interrupted or reduced due to conditions on the Government's system which have not been arranged for and agreed to in advance, the demand charge for capacity made available will be reduced as to the kilowatts of such capacity which have been interrupted or reduced in accordance with the following formula:

Number of kilowatts unavailable
for at least 12 hours in any
calendar day

X $\frac{\$1.02}{\text{Number of days in billing month}}$

October 1, 1979

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHEASTERN POWER ADMINISTRATION

Wholesale Power Rate Schedule ALA-1-B

Availability:

This rate schedule shall be available to the Alabama Electric Cooperative, Incorporated (hereinafter called the Cooperative).

Applicability:

This rate schedule shall be applicable to power and accompanying energy generated at the Allatoona, Buford, Clark Hill, Walter F. George, Hartwell, Millers Ferry, West Point, Jones Bluff, and Carters Project and sold under contract between the Cooperative and the Government.

Character of Service:

The electric capacity and energy supplied hereunder will be three-phase alternating current at a nominal frequency of 60 Hertz and shall be delivered at the Walter F. George Project or other points of interconnection between the Cooperative and Alabama Power Company.

Monthly Rate:

The monthly rate for capacity and energy sold under this rate schedule shall be:

Demand Charge:

\$1.02 per kilowatt of total contract demand.

\$0.28 per kilowatt for standby capacity made available, plus \$0.035 per kilowatt per calendar day for such capacity as the Cooperative actually utilizes.

Energy Charge:

3.00 mills per kilowatt-hour for scheduled energy.

Contract Demand:

The contract demand is the amount of capacity in kilowatts stated in the contract which the Government is obligated to supply and the Cooperative is entitled to receive.

Energy to be Furnished by the Government:

The Government will sell to the Cooperative and the Cooperative will purchase from the Government those quantities of energy specified by contract as available to the Cooperative for scheduling on a weekly basis. Energy quantities for a billing month shall be the energy scheduled by the Cooperative for the month.

Billing Month:

The billing month for power sold under this schedule shall end at 12:00 midnight on the last day of each calendar month.

Power Factor:

The Cooperative shall take capacity and energy from the Government at such power factor as will best serve the Cooperative's system from time to time; provided, that the Cooperative shall not impose a power factor of less than .85 lagging on the Government's facilities which requires operation contrary to good operating practice or results in overload or impairment of such facilities.

Service Interruption:

When capacity and energy delivery to the Cooperative's system for the account of the Government is reduced or interrupted and such reduction is not due to conditions on the Cooperative's system or has not been

planned and agreed to in advance, the demand charge for the month for capacity made available shall be reduced as to the kilowatts of such capacity which have been interrupted or reduced in accordance with the following formula:

Number of kilowatts unavailable
for at least 12 hours in any
calendar day

$$\begin{array}{r} \text{X} \quad \frac{\$1.02}{\text{Number of days}} \\ \text{in billing month} \end{array}$$

October 1, 1979

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHEASTERN POWER ADMINISTRATION

Wholesale Power Rate Schedule MISS-1-B

Availability:

This rate schedule shall be available to the South Mississippi Electric Power Association (hereinafter called the Cooperative).

Applicability:

This rate schedule shall be applicable to power and accompanying energy generated at the Allatoona, Buford, Clark Hill, Walter F. George, Hartwell, Millers Ferry, West Point, Jones Bluff, and Carters Projects and sold under contract between the Cooperative and the Government.

Character of Service:

The electric capacity and energy supplied hereunder will be three-phase alternating current at a nominal frequency of 60 Hertz and shall be delivered at points of interconnection between the Cooperative and Mississippi Power Company.

Monthly Rate:

The monthly rate for capacity and energy sold under this rate schedule shall be:

Demand Charge:

\$1.02 per kilowatt of total contract demand.

Energy Charge:

3.65 mills per kilowatt-hour for scheduled energy.

Contract Demand:

The contract demand is the amount of capacity in kilowatts stated in the contract which the Government is obligated to supply and the Cooperative is entitled to receive.

Energy to be Furnished by the Government:

The Government will sell to the Cooperative and the Cooperative will purchase from the Government those

quantities of energy specified by contract as available to the Cooperative for scheduling on a weekly basis. Energy quantities for a billing month shall be the energy scheduled by the Cooperative for the month.

Billing Month:

The billing month for power sold under this schedule shall end at 12:00 midnight on the last day of each calendar month.

Power Factor:

The Cooperative shall take capacity and energy from the Government at such power factor as will best serve the Cooperative's system from time to time; provided, that the Cooperative shall not impose a power factor of less than .85 lagging on the Government's facilities which requires operation contrary to good operating practice or results in overload or impairment of such facilities.

Service Interruption:

When capacity and energy delivery to the Cooperative's system for the account of the Government is reduced or interrupted and such reduction is not due to conditions on the Cooperative's system or has not been planned and agreed to in advance, the demand charge for the month for capacity made available shall be reduced as to the kilowatts of such capacity which have been interrupted or reduced in accordance with the following formula:

Number of kilowatts unavailable
for at least 12 months in any
calendar day

$$\begin{array}{r} \text{X} \quad \frac{\$1.02}{\text{Number of days}} \\ \text{in billing month} \end{array}$$

October 1, 1979

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHEASTERN POWER ADMINISTRATION

Wholesale Power Rate Schedule SC-1-B

Availability:

This rate schedule shall be available to the South Carolina Public Service Authority (hereinafter called the Customer).

Applicability:

This rate schedule shall be applicable to power and accompanying energy generated at the Clark Hill Project (hereinafter called the Project) and sold in wholesale quantities.

Character of Service:

Electric capacity and energy supplied hereunder will be

three-phase alternating current at a nominal frequency of 60 cycles per second and shall be delivered at a nominal voltage of 115,000 volts at the 115 kv bus of the Project power plant. The actual operating voltage of the Government shall within the limits of good operating practice be suitable for operation with the Customer's system.

Monthly Rate:

The monthly rate for capacity and energy sold under this rate schedule shall be:

Demand Charge:

\$1.02 per kilowatt per billing month for dependable capacity made available to the Customer for its own use.

\$0.28 per kilowatt per billing month for standby capacity made available, plus \$0.035 per kilowatt per calendar day (or fraction thereof) for such capacity as the Customer actually utilizes.

Energy Charge:

3.00 mills per kilowatt-hour for energy declared for the peak period hours and for energy made available to meet stream flow requirements.

2.25 mills per kilowatt-hour for dump energy.

Energy Sold to the Customer:

The Customer shall purchase and pay for all dump energy made available by the Government and accepted by the Customer. Additionally, the Customer shall purchase and pay for all energy, exclusive of dump energy, declared and made available from the Project to the Customer's system over and above such energy made available for transmission to the Government's other preference customers.

Billing Month:

All project energy shall be accounted for on a weekly basis and the total quantities of energy billed monthly shall be the sum of the weekly quantities. Energy declared or made available for any week which falls within 2 billing months shall be divided between the months on the basis of weekly schedules for energy delivery furnished by the Customer.

The billing month for power sold under this rate schedule shall end at 12:00 midnight on the last day of each calendar month.

Power Factor:

The Customer shall not impose a power factor of less than .85 lagging on the Government's facilities which requires operation contrary to good operating practice or results in overload or impairment of such facilities.

Condenser Operation:

The Government shall, upon the request of the Customer, cause its generating units (up to the maximum number specified by contract) to be operated as condensers if, in the sole judgment of the Government, such operation is not contrary to good operating practices, is

not detrimental to such generating facilities in excess of ordinary wear and tear, and does not overload such generating facilities. Such condenser operation, subject to the preceding limitations, shall be in accordance with procedures and schedules developed and agreed upon from time to time by the operating representatives of the parties hereto. The Customer shall pay the Government \$5.65 per generating unit so operated for each hour that such condenser operation is requested by the Customer.

Service Interruption:

When capacity made available to the Customer's system is reduced or interrupted for 1 hour or longer, and such reduction or interruption is not agreed to in advance nor due to conditions on the Purchaser's system, the monthly demand charge for dependable capacity shall be reduced for each on-peak hour (the nearest number of whole hours) that such capacity is reduced or interrupted, by an amount equal to \$1.02 divided by the number of peak hours in the billing month times the reduction, in kilowatts, of such capacity; and the amount of energy previously scheduled and not taken during the time of interruption shall be placed in storage to the Customer's account. If the Customer advises the Government within 1 working day after a day in which energy is placed in storage that it does not desire to retain ownership of such energy, the ownership of the energy will revert to the Government and the Customer shall not be obligated to pay for such energy.

October 1, 1979

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHEASTERN POWER ADMINISTRATION

Wholesale Power Rate Schedule SC-2-B

Availability:

This rate schedule shall be available to any of the following whose requirements or a portion thereof the Government shall contract to supply by delivery from the South Carolina Public Service Authority's (hereinafter called the Authority) system: a municipality or county located in part or completely within the Authority's service area, owning its own transmission or distribution system, and desiring to purchase capacity and energy from the Government for resale to the public in its territory; Central Electric Cooperative, Incorporated; or an electric cooperative not a member of Central, operating under the laws of the State of South Carolina, and located in part or completely within the service area of the Authority desiring to purchase capacity and energy from the Government for resale to ultimate consumers under the provisions of said laws (any one of such municipalities, counties, or cooperatives is hereinafter called the Customer).

Applicability:

This rate schedule shall be applicable to power and accompanying energy generated at the Clark Hill Project (hereinafter called the Project) and sold in wholesale quantities.

Character of Service:

The electric capacity and energy supplied hereunder will be three-phase alternating current at a nominal frequency of 60 cycles per second delivered at the delivery points of the Customer on the Authority's transmission and distribution system. The voltage of delivery will be maintained within the limits established by the state regulatory commission.

Monthly Rate:

The monthly rate for capacity and energy sold under this rate schedule shall be:

Demand Charge:

\$1.02 per kilowatt of total contract demand.

Energy Charge:

3.65 mills per kilowatt-hour.

Energy to be Furnished by the Government:

The Government will sell to the Customer and the Customer will purchase from the Government energy from the Project each billing month up to a total amount annually of 4,500 hours per kilowatt of contract demand.

For billing purposes, the energy allocated on an annual basis to accompany the Customer's contract demand as assigned to individual delivery points shall be allocated in equal quantities each day throughout the year. Such Customer shall be billed by the Government by delivery points for its contract demand and for its accompanying monthly energy allocation in amounts determined by multiplying its respective daily allocation by the number of days in the billing month. The quantity of energy to be billed under this rate schedule in any billing month shall be the quantity considered to have been transmitted for the account of the Government by the Authority.

Billing Month:

The billing month for power sold under this rate schedule shall end at 12:00 midnight on the last day of each calendar month.

Conditions of Service:

The Customer shall at its own expense provide, install, and maintain on its side of each delivery point the equipment necessary to project and control its own system. In so doing, the installation, adjustment and setting of all such control and protective equipment at or near the point of delivery shall be coordinated with that which is installed by and at the expense of the Authority on its side of the delivery point.

Service Interruption:

When the energy delivery to the Customer's system for the account of the Government is reduced or interrupted

for 1 hour or longer, and such reduction or interruption is not due to conditions on the Customer's system, the demand charge for the month shall be appropriately reduced.

October 1, 1979

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHEASTERN POWER ADMINISTRATION

Wholesale Power Rate Schedule CAR-1-B

Availability:

This rate schedule shall be available to public bodies and cooperatives (any one of which is hereinafter called the Customer) in North Carolina and South Carolina to whom power may be wheeled pursuant to contract between the Duke Power Company (hereinafter called the Company) and the Government.

Applicability:

This rate schedule shall be applicable to power and accompanying energy generated at the Hartwell and Clark Hill Projects (hereinafter called the Projects) and sold in wholesale quantities.

Character of Service:

The electric capacity and energy supplied hereunder will be three-phase alternating current at a nominal frequency of 60 cycles per second delivered at the delivery points of the Customer on the Company's transmission and distribution system. The voltage of delivery will be maintained within the limits established by the state regulatory commission.

Monthly Rate:

The monthly rate for capacity and energy sold under this rate schedule shall be:

Demand Charge:

\$1.02 per kilowatt of total contract demand.

Energy Charge:

3.65 mills per kilowatt-hour.

Energy to be Furnished by the Government:

The Government will sell to the Customer and the Customer will purchase from the Government energy from the Projects to the extent that it is available at the Projects each billing month up to a total amount annually of 4,500 hours per kilowatt of contract demand.

For billing purposes, the energy allocation available on an annual basis to accompany the Customer's contract demand as assigned to individual delivery points shall be allocated in equal quantities each day throughout the year. In those billing months when the quantity of energy available from the Projects, less six and one-half

(6-1/2) percent losses, is sufficient to supply the energy allocations which accompany the total contract demands of all customers purchasing power pursuant to this rate schedule, the Customer will be billed by the Government by delivery points for its monthly energy allocation in an amount determined by multiplying the daily energy allocation by the number of days in the billing month. In those billing months when energy available from the Projects, less six and one-half (6-1/2) percent losses, is insufficient to supply the energy allocations which accompany the total contract demands of all customers purchasing power pursuant to this rate schedule, the Customer shall be billed by the Government by delivery points for that portion of its monthly energy allocation determined by multiplying the ratio which the total energy available from the Projects for all said Customers' use during the particular billing month bears to the quantity necessary to supply the energy allocations which accompany the total contract demands of all said customers during such month by the quantity of energy necessary to meet the energy allocation of the Customer for said billing month.

Billing Month:

The billing month for power sold under this schedule shall end at 12:00 midnight on the 20th day of each calendar month.

Conditions of Service:

The customer shall at its own expense provide, install, and maintain on its side of each delivery point the equipment necessary to protect and control its own system. In so doing, the installation, adjustment and setting of all such control and protective equipment at or near the point of delivery shall be coordinated with that which is installed by and at the expense of the Company on its side of the delivery point.

Service Interruption:

When energy delivery to the Customer's system for the account of the Government is reduced or interrupted for 1 hour or longer, and such reduction or interruption is not due to conditions on the Customer's system, the demand charge for the month shall be appropriately reduced.

October 1, 1979

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHEASTERN POWER ADMINISTRATION

Wholesale Power Rate Schedule CAR-2-B

Availability:

This rate schedule shall be available to the Duke Power Company (hereinafter called the Company).

Applicability:

This rate schedule shall be applicable to electric capa-

city and energy generated at the Hartwell and Clark Hill Projects (hereinafter called the Projects) and sold under contract between the Government and the Company.

Character of Service:

Electric capacity and energy delivered to the Company will be three-phase alternating current at a nominal frequency of 60 cycles per second and will be delivered at approximately 230,000 volts where the Company's transmission line is connected to the bus in the Hartwell switchyard and at approximately 115,000 volts where the Company's transmission line is connected to the bus at Clark Hill.

Monthly Rate:

The monthly rate for capacity and energy sold under this rate schedule shall be:

Demand Charge:

\$1.02 per kilowatt per billing month for dependable capacity made available to the Company for its own use.

Energy Charge:

- (1) 3.00 mills per kilowatt-hour for energy declared for the peak period hours.
- (2) 2.25 mills per kilowatt-hour for energy declared for other than peak period hours.
- (3) 2.25 mills per kilowatt-hour for dump energy.

Energy Sold to the Company:

The Company shall purchase and pay for all dump energy made available by the Government and accepted by the Company. Additionally, the Company shall purchase and pay for all energy, exclusive of dump energy, declared and made available from the Projects to the Company's system in any billing month after first deducting 810,375 kilowatt-hours multiplied by the number of days in said billing month; provided, however, that the energy to be deducted shall first come from minimum release energy and energy declared for the eighty-four (84) peak period hours per week as specified by contract.

Billing Month:

The billing month for power sold under this schedule shall end at 12:00 midnight on the 20th day of each calendar month.

Power Factor:

The Company shall take capacity and energy from the Government at such power factor as will best serve the Company's system from time to time, provided that the Company shall not impose a power factor of less than .85 lagging on the Government's facilities which requires operation contrary to good operating practice or results in overload or impairment of such facilities or unreasonably interferes with the delivery of capacity and energy by the Government to the Company and to its other Customers.

Condenser Operation:

The Government shall, upon the request of the Company, cause one or two of its generating units at the Projects to be operated as condensers if, in the sole judgment of the Government, such operation does not unreasonably interfere with the delivery of capacity and energy by the Government to any of its customers, is not contrary to good operating practice, is not detrimental to such generating facilities in excess of ordinary wear and tear, and does not overload such generating facilities. Such condenser operation, subject to the preceding limitations, shall be in accordance with procedures and schedules developed and agreed upon from time to time by the operating representatives of the parties hereto. The Company shall pay the Government \$10.15 per generating unit for units at Clark Hill each hour that such condenser operation is requested by the Company.

Service Interruption:

When delivery to the Company is interrupted or reduced due to conditions on the Government's system which have not been arranged for and agreed to in advance, the charge for dependable capacity will be reduced as to the kilowatts of such capacity which have been interrupted or reduced in the proportion that the number of declaration hours during such period of interruption or reduction bears to the total number of declaration hours during the period covered by such charge. For purposes of this rate schedule the declaration hours consist of 100 hours per week as specified in the contract.

October 1, 1979

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR
RESOURCE APPLICATIONS

In the Matter of:

Southeastern Power Administration—) Rate Order
Jim Woodruff Project Power Rates) No. SEPA-10

ORDER EXTENDING CONFIRMATION
AND APPROVAL OF POWER RATES
ON AN INTERIM BASIS
(September 30, 1980)

Pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act, Public Law 95-91, the functions of the Secretary of the Interior and the Federal Power Commission under Section 5 of the Flood Control Act of 1944, 16 U.S.C. 825s, relating to the Southeastern Power Administration (SEPA) were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 F.R. 60636 (December 28, 1978), the Secretary of Energy delegated

to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve and place in effect such rates on an interim basis and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. This Rate Order is issued pursuant to the delegation to the Assistant Secretary.

BACKGROUND

On August 15, 1979, the Assistant Secretary for Resource Applications issued Rate Order No. SEPA-6 confirming and approving on an interim basis, effective October 20, 1979, Wholesale Power Rate Schedules JW-1 (Revised) and JW-2-B applicable to power from the Jim Woodruff Project. These rate schedules were to remain in effect on an interim basis through October 19, 1980, unless such period was extended or until FERC confirmed and approved them or substitute rate schedules on a final basis. The rate schedules, together with a May 1979 Repayment Study and other supporting data, copies of a transcript of a Public Comment Forum and applicable power contracts, were submitted to FERC with the request that the rate schedules be confirmed and approved on a final basis.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby extend confirmation and approval on an interim basis, effective October 20, 1980, of attached Rate Schedules JW-1 (Revised) and JW-2-B. These rate schedules shall remain in effect on an interim basis through October 19, 1981, unless such period is extended or until the FERC confirms and approves them or substitute rate schedules on a final basis.

Issued at Washington, D.C., this 30th day of September, 1980.

Ruth M. Davis
Assistant Secretary
Resource Applications

UNITED STATES
DEPARTMENT OF THE INTERIOR
SOUTHEASTERN POWER ADMINISTRATION

Wholesale Power Rate Schedule JW-1 (Revised)

Availability:

This rate schedule shall be available to public bodies and cooperatives served by the Florida Power Corporation and having points of delivery within 150 miles of Jim Woodruff Project (hereinafter called the Project).

Applicability:

This rate schedule shall be applicable to firm power and accompanying energy made available by the Government from the Project and sold in wholesale quantities.

Character of Service:

The electric capacity and energy supplied hereunder will be three-phase alternating current at a nominal frequency of 60 cycles per second delivered at the delivery points of the customer.

Monthly Rate:

The monthly rate for capacity and energy made available or delivered under this rate schedule shall be:

Demand Charge:

\$1.50 per kilowatt of monthly billing demand.

Energy Charge:

4.5 mills per kilowatt hour.

Billing Demand:

The monthly billing demand for any billing month shall be the lower of (a) the Customer's contract demand or (b) the sum of the maximum 30-minute integrated demands for the month at each of the Customer's points of delivery; provided, that, if an allocation of contract demand to delivery points has become effective, the 30-minute maximum integrated demand for any point of delivery shall not be considered to be greater than the portion of the Customer's contract demand allocated to that point of delivery.

Capacity Made Available:

The capacity which the Government will supply to meet the demand of the Customer in any billing month will be the maximum amount of capacity required for that purpose up to the contract demand. Such maximum amount of capacity required will be determined by adding the maximum 30-minute integrated measured demands at all points of delivery of the Customer located within 150 miles of the Project power station. At such time as the demand of the Customer approximates the contract demand, the Government will allocate the contract demand among the Customer's then existing delivery points on the basis of the demands recorded as of that time at each such point of delivery adjusted to round each point's allocation to the nearest 10 kilowatts. The allocation of contract demand to delivery points shall become effective the billing month that the Customers' total demand at said delivery points exceeds its contract demand.

Energy Made Available:

During any billing month in which the Government supplies all the Customer's capacity requirements, the Government will make available such energy as the Customer may require to supply its load. In any billing month when both the Government and the Florida Power Corporation are supplying capacity to a delivery point, each kilowatt of capacity supplied to such point

during such month will be considered to be accompanied by an equal quantity of energy.

Billing Month:

The billing month for power sold under this schedule shall end at 12:00 midnight on the 20th day of each calendar month.

Conditions of Service:

The customer shall at its own expense provide, install, and maintain on its side of each delivery point the equipment necessary to protect and control its own system. In so doing, the installation, adjustment, and setting of all such control and protective equipment at or near the point of delivery shall be coordinated with that which is installed by and at the expense of the Florida Power Corporation on its side of the delivery point.

Service Interruption:

When energy delivered to the Customer's system for the account of the Government is reduced or interrupted for 1 hour or longer, and such reduction or interruption is not due to conditions on the Customer's system or has not been planned and agreed to in advance, the demand charge for the month shall be appropriately reduced.

August 19, 1967

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHEASTERN POWER ADMINISTRATION

Wholesale Power Rate Schedule JW-2-B

Availability:

This rate schedule shall be available to the Florida Power Corporation (hereinafter called the Company).

Applicability:

This rate schedule shall be applicable to electric energy generated at the Jim Woodruff Project (hereinafter called the Project) and sold to the Company in wholesale quantities.

Points of Delivery:

Power sold to the Company by the Government will be delivered at the connection of the Company's transmission system with the Project bus.

Character of Service:

Electric power delivered to the Company will be three-phase alternating current at a nominal frequency of 60 cycles per second.

Monthly Rate:

The monthly rate for energy sold under this schedule shall be equal to 60 percent of the calculated saving in the

cost of fuel per kWh to the Company determine as follows:

$$\text{Energy Rate} = 60\% \times \frac{F_m}{S_m} \text{ [Computed to the nearest } \$0.00001 \text{ (1/100 mill) per kWh]}$$

Where: F_m = Company fuel cost in the current period as defined in Federal Power Commission Order 517 issued November 13, 1974, Docket No. R-479.

S_m = Company sales in the current period reflecting only losses associated with wholesale sales for resale. Sale shall be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) inter-system sales, less estimated wholesale losses (based on average transmission loss percentage for preceding calendar year).

Method of Application: The energy rate applied during the current billing month will be based on costs and equated sales for the second month preceding the billing month.

Determination of Energy Sold:

Energy will be furnished by the Company to supply any excess of Project use over Project generation. Energy so supplied by the Company will be deducted from the actual deliveries to the Company's system to determine the net deliveries for energy accounting and billing purposes. Energy for Project use shall consist of energy used for station service, lock operation, Project yard, village lighting, and similar uses.

The on-peak hours shall be the hours between 7:00 a.m. and 11:00 p.m., Monday through Sunday, inclusive. Off-peak hours shall be all other hours.

All energy made available to the Company, exclusive of transfers to the Georgia Power Company for the account of the Government, shall to the extent required be classified as energy transmitted to the Government's preference customers served from the Company's system. All energy made available to the Company from the Project shall be separated on the basis of the metered deliveries to it at the Project during on-peak and off-peak hours, respectively. Such on-peak energy as is made available to the Company at the points of interconnection with Georgia Power Company shall be determined from schedules of deliveries. Deliveries to preference customers of the Government shall be divided on the basis (with allowance for losses) of 77 percent being considered as on-peak energy and 23 percent being off-peak energy. Such percentages may by mutual consent be changed from time to time as further studies show to be appropriate. Deliveries made to the Georgia Power Company shall be on the basis (with allowances for losses) of schedules of deliveries. In the event that in classifying energy there is more than enough on-peak energy available to supply on-peak requirements of the Government's preference customers but less than enough off-peak energy

available to supply such customers off-peak requirements, such excess on-peak energy may be applied to the extent necessary to meet off-peak requirements of such customers in lieu of purchasing deficiency energy to meet such off-peak requirements.

Any on-peak and off-peak Project energy made available in any billing month over and above that required for transfers to the Georgia Power Company for the account of the Government and to meet the above requirements of preference customers shall be classified as energy sold under this rate schedule.

The energy requirements of the Government's preference customers shall be the total energy requirements of such customers so long as the Government is supplying the total capacity required. In any month when both the Government and the Company are supplying capacity to a preference customer, each kilowatt of capacity shall be considered to be accompanied by an equal quantity of energy. The energy supplied by the Government shall come from its own resources or from purchases from the Company and shall be accounted for as transmitted for the account of the Government. Energy delivered to preference customers by the Company shall be increased by 7 percent to provide for losses in transmission.

Billing Month:

The billing month under this schedule shall end at 12:00 midnight on the 20th day of each calendar month.

Power Factor:

The purchaser and seller under this rate schedule agree that they will both so operate their respective systems that neither party will impose an undue reactive burden on the other.

October 20, 1979

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR
RESOURCE APPLICATIONS

In the Matter of:

Western Area Power Administration—) Rate Order
Central Valley Project Power Rates) No. WAPA-5

ORDER CONFIRMING AND APPROVING
AN EXTENSION OF POWER RATES
ON AN INTERIM BASIS
(October 3, 1980)

Pursuant to section 302(a) of the Department of Energy Organization Act, Public Law 95-91, 91 Stat. 565, the power marketing functions of the Secretary of the Interior, under the Reclamation Act of 1902, 32 Stat. 388, as amended and supplemented by subsequent enactments, particularly by section 9(c) of the Reclamation Act of

1939, 43 U.S.C. 485h(c), for the Bureau of Reclamation were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 FR 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve, and place in effect such rates on an interim basis, and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. This rate order is issued pursuant to the delegation to the Assistant Secretary.

BACKGROUND

Pursuant to Delegation Order No. 0204-33, on October 2, 1979, the Assistant Secretary for Resource Applications issued Rate Order No. WAPA-2 (44 FR 57962, October 9, 1979) confirming and approving on an interim basis, effective November 1, 1979, Rate Schedules CV-F4 and CV-P3 for power marketed by the Western Area Power Administration's (Western) Central Valley Project (CVP). The rate order stated that the rates "... shall remain in effect on an interim basis for a period of 12 months unless such period is extended or until the FERC confirms and approves them, or substitute rates, on a final basis." The rate schedules were submitted to the FERC for confirmation and approval on a final basis by the Assistant Secretary's letter of October 2, 1979.

DISCUSSION

The FERC has not yet acted on the CVP power rates submitted to the FERC on October 2, 1979. It appears that unless the rates are extended they will terminate on October 31, 1980.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, effective November 1, 1980, an extension of existing Rate Schedules CV-F4 and CV-P3. These rates shall remain in effect through October 31, 1981, unless extended, or until the FERC confirms and approves them, or substitute rates, on a final basis.

Issued in Washington, D.C., October 3, 1980.

Ruth M. Davis
Assistant Secretary
Resource Applications

Rate Schedule CV-F4
(Supersedes Rate
Schedule CV-F3R)

UNITED STATES DEPARTMENT OF ENERGY WESTERN AREA POWER ADMINISTRATION

Central Valley Project, California

SCHEDULE OF RATES FOR WHOLESALE FIRM POWER SERVICE

Effective:

November 1, 1979.

Available:

In the area served by the Central Valley Project.

Applicable:

To wholesale firm power customers for general power service supplied through one meter at one point of delivery.

Character and Conditions of Service:

Alternating current, sixty hertz, three phase, delivered and metered at the voltages and points established by contract.

Monthly Rate:

DEMAND CHARGE: \$2.00 per kilowatt of billing demand.

ENERGY CHARGE: 5.11 mills per kilowatt-hour for all energy use up to, but not in excess of, the energy obligation under the power sales contract.

BILLING DEMAND: The billing demand will be the highest 30-minute integrated demand established during the month up to, but not in excess of, the delivery obligation under the power sales contract.

ENERGY OBLIGATION: The maximum kilowatt-hour obligation of the United States during the month as established under the power sales contract.

MINIMUM BILL: \$2.00 per kilowatt of the effective contract rate of delivery.

Billing for Unauthorized Overruns:

For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual firm power and/or energy obligations, such overrun shall be billed at ten times the above rate.

Adjustments

For character and conditions of service:

If delivery is made at transmission voltage so that the United States is relieved of substation costs, five percent discount will be allowed on the demand and energy charges.

For transformer losses:

If delivery is made at transmission voltage but metered on the low-voltage side of the substation, the meter

readings will be increased two percent to compensate for transformer losses.

For power factor:

None. The customer will normally be required to maintain a power factor at the point of delivery of between 95 percent lagging and 95 percent leading.

Rate Schedule CV-P3
(Supersedes Rate
Schedule CV-P2R)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

Central Valley Project, California

SCHEDULE OF RATES FOR COMMERCIAL
IRRIGATION AND/OR DRAINAGE PUMPING
SERVICE AND FOR WHOLESALE FIRM
POWER SERVICE WHEN SUPPLIED IN
CONJUNCTION THEREWITH

Effective:

November 1, 1979.

Available:

In the area served by the Central Valley Project.

Applicable:

To commercial irrigation customers for their own use for, or for resale for, irrigation and/or drainage pumping and purposes incidental thereto supplied through one meter at one point of delivery, and for the purposes other than irrigation and/or drainage pumping service when supplied in conjunction with the pumping service through the same meter at the same point of delivery.

Character and Conditions of Service:

Alternating current, sixty hertz, three phase, delivered and metered at the voltages and points established by contract.

Monthly Rate:

DEMAND CHARGE: \$2.00 per kilowatt of billing demand.

ENERGY CHARGE: 5.11 mills per kilowatt-hour for all energy use up to, but not in excess of, the energy obligation under the power sales contract.

BILLING DEMAND: The billing demand will be the highest 30-minute integrated demand established during the month up to, but not in excess of, the delivery obligation under the power sales contract.

ENERGY OBLIGATION: The maximum kilowatt-hour obligation of the United States during the month as established under the power sales contract.

MINIMUM BILL: None.

Billing for Unauthorized Overruns:

For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual power and/or energy obligations, such overrun shall be billed at ten times the above rate.

Adjustments:

For character and conditions of service:

If delivery is made at transmission voltage so that the United States is relieved of substation costs, five percent discount will be allowed on the demand and energy charges.

For transformer losses:

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

For power factor:

None. The customer will normally be required to maintain a power factor at the point of delivery of between 95 percent lagging and 95 percent leading.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR
RESOURCE APPLICATIONS

In the Matter of:

Alaska Power Administration—) Rate Order
Eklutna Project Power Rates) No. APA-4

ORDER CONFIRMING AND APPROVING
AN EXTENSION OF POWER RATES
ON AN INTERIM BASIS
(November 20, 1980)

Pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act, Public Law 95-91, 91 Stat. 565, the functions of the Secretary of the Interior and the Federal Power Commission under the Eklutna Project Act of July 31, 1950, 64 Stat. 382, as amended were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 F.R. 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve, and place in effect such rates on an interim basis and delegated to the Federal Energy Regulatory Commission the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the

delegation. This rate order is issued pursuant to the delegation to the Assistant Secretary.

BACKGROUND

Pursuant to Delegation Order No. 0204-33, on December 4, 1979, the Assistant Secretary for Resource Applications issued Rate Order No. APA-2 (44 F.R. 70861, December 10, 1979) confirming and approving on an interim basis, effective January 1, 1980, Rate Schedules A-F8 and A-N7 for power marketed by the Alaska Power Administration's Eklutna Project. The rate order stated that the rates "... shall remain in effect on an interim basis for a period of 12 months unless such period is extended or until the FERC confirms and approves them, or substitute rates, on a final basis." The rate schedules were submitted to the FERC for confirmation and approval on a final basis by the Assistant Secretary's letter of December 4, 1979.

DISCUSSION

Inasmuch as the Federal Energy Regulatory Commission is not expected to complete its confirmation and approval of the Eklutna Project power rate by December 31, 1980, a further extension of the interim rate is necessary.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, effective January 1, 1981, an extension of existing Rate Schedules A-F8 and A-N7. These rates shall remain in effect through December 31, 1981, unless extended, or until the FERC confirms and approves them, or substitute rates, on a final basis.

Issued in Washington, D.C., November 20th, 1980.

Ruth M. Davis
Assistant Secretary
Resource Applications

SCHEDULE A-F8

UNITED STATES DEPARTMENT OF ENERGY
ALASKA POWER ADMINISTRATION

Eklutna Project, Alaska

SCHEDULE OF RATES FOR WHOLESALE FIRM POWER SERVICE

Effective:

January 1, 1980.

Available:

In the area served by the Eklutna Project, Alaska.

Applicable:

To wholesale power customers for general power service.

Character and Conditions of Service:

Alternating current, sixty cycles, three-phase, delivered and metered at the low-voltage side of substation.

Monthly Rate:

CAPACITY CHARGE: None

ENERGY CHARGE: All energy at 12.5 mills per kilowatt-hour.

Minimum Annual Capacity Charge:

None.

Billing Demand:

Not Applicable.

Adjustments

For Transformer Losses:

If delivery is made at the high-voltage side of the customer's substation but metered at the low-voltage side, the meter readings will be increased 2 percent to compensate for transformer losses.

For Power Factor:

None. The customer will normally be required to maintain a power factor at the point of delivery of between 90 percent lagging and 90 percent leading.

For Auxiliary Power Service:

Auxiliary power supplies may be used in conjunction with the service hereunder if the parties hereto, prior to the Contractor's utilization of any such auxiliary power supply, have entered into a written operating agreement defining the procedure by which the amount of power and energy supplied by the United States will be determined.

SCHEDULE A-N7

UNITED STATES
DEPARTMENT OF ENERGY
ALASKA POWER ADMINISTRATION

Eklutna Project, Alaska

SCHEDULE OF RATES FOR NONFIRM SERVICE

Effective:

January 1, 1980.

Available:

In the area served by the Eklutna Project, Alaska.

Applicable:

To firm power customers normally maintaining generating facilities or other sources of energy sufficient to supply their requirements.

Character and Conditions of Service:

Alternating current, sixty cycles, three-phase, delivered and metered at points of delivery and voltage to be determined by the Alaska Power Administration.

Monthly Rate:

DEMAND CHARGE: None.

ENERGY CHARGE: 6.0 mills per kilowatt-hour for all energy under this schedule.

Minimum Bill:

None.

Adjustments:

For Character and Conditions of Service:

None.

For Transformer Losses:

If delivery is made at the high-voltage side of the customer's substation but metered at the low-voltage side, the meter readings will be increased 2 percent to compensate for transformer losses.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR
RESOURCE APPLICATIONS

In the Matter of:

Southwestern Power Administration—) Rate Order
Rate Schedule TDC-2) No. SWPA-7

ORDER CONFIRMING, APPROVING AND
PLACING INCREASED TRANSMISSION RATES
IN EFFECT ON AN INTERIM BASIS
(Date December 11, 1980)

Pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act, Public Law 95-91, the functions of the Secretary of the Interior and the Federal Power Commission under Section 5 of the Flood Control Act of 1944, 16 U.S.C. 825s, for the Southwestern Power Administration (Southwestern) were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 RE (FR Ed) 60636 (December 28, 1978) the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, to confirm, approve, and place in effect such rates on an interim basis, and delegated to the Federal Energy Regu-

latory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. This rate order is issued pursuant to the delegation to the Assistant Secretary.

BACKGROUND

Existing Rates

On January 23, 1973, the Assistant Secretary for Power and Water (Water and Power-Ed.) Resources, U.S. Department of the Interior approved Southwestern's schedule of transmission and/or displacement charges (Schedule TDC) for transmission of non-Federal power and energy over the Southwestern transmission system for a period ending January 23, 1976. No regulatory authority approval was required by statute.

On June 29, 1973, by the approval of the Assistant Secretary, Energy and Minerals, U.S. Department of the Interior, Schedule TDC was amended to provide that surplus capacity in Southwestern transmission facilities could be made available to other than Southwestern customers. No regulatory authority approval was required and the Assistant Secretary's approval was extended until June 30, 1976. Schedule TDC (Amended) was revised and later approved by the Assistant Secretary, Energy and Minerals, U.S. Department of the Interior, on August 2, 1976, for a period ending June 30, 1979. Schedule TDC (Revised) maintained the same pricing as the original Schedule TDC with provision to correct certain inequities in the adjustment for power factor.

On June 18, 1979, the Assistant Secretary for Resource Applications, U.S. Department of Energy approved the extension of the existing Schedule TDC (Revised), on an interim basis, effective July 1, 1979, for a period ending June 30, 1980, and submitted the extension to the FERC for final confirmation and approval.

On July 1, 1980, the Assistant Secretary for Resource Applications, U.S. Department of Energy extended the confirmation and approval of Schedule TDC (Revised), on an interim basis, through December 31, 1980. This extension was necessary to allow Southwestern time to complete a detailed study of the rates and to provide the public the opportunity to comment on any proposed revision.

The rates that are the subject of this order supersede the following existing rates:

1. Transmission and delivery of power and energy over the 138/161 kV transmission facilities.....\$0.25/kW/mo.
2. Transmission of power and energy over the 138/161 kV transmission lines and delivered at stepdown substations directly connected thereto or from lines at 69 kV ...\$0.35/kW/mo.

3. Transmission of power and energy over the 138/161 kV transmission lines, with further transmission over 69 kV lines and delivered at stepdown substations connected thereto at distribution voltage\$0.60/kW/mo.
4. Transmission and delivery of supplemental energy used for the purpose of firming peaking power delivered from the Southwestern system \$0.0005/kWh.

Public Notice and Comment

Opportunity for public review and comment on proposed transmission rates was announced by notice published in the Federal Register on October 1, 1980 (45 FR 65027).

The public participation process produced few questions and comments. All of the comments have in some form been incorporated in developing the TDC-2 rates which are confirmed, approved and placed in effect by this Rate Order. Responses to the three comments are contained in the following discussion.

DISCUSSION

Thirteen customers are presently being billed for transmission service under Schedule TDC (Revised): Ark-Mo Power Company; Public Service Company of Oklahoma; Associated Electric Cooperative; Western Farmers Electric Cooperative; Carthage, Missouri; Kennett, Missouri; New Madrid, Missouri; Jonesboro, Arkansas; Paragould, Arkansas; Piggott, Arkansas; Poplar Bluff, Missouri; Sikeston, Missouri; and Grand River Dam Authority. Revenue under this rate schedule is estimated to be about 1% of the total expected integrated system gross revenue.

The public comments and responses to them are as follows:

Transmission Losses

A suggestion was made that Rate Schedule TDC-2 should contain a paragraph concerning the transmission losses. In response to this comment, it should be noted that due to variations in service conditions the specific amounts of losses have to be negotiated and agreed upon in each contract. It was decided, however, that inclusion of a general statement concerning losses in the Rate Schedule has merit. Accordingly, Rate Schedule TDC-2 language was revised to indicate that transmission losses will be provided by the customer as specified by contract.

Interruptible Transmission

This comment has to do with the provision of wheeling service on a short-term basis. While the idea is sound the implementation of it caused Southwestern's staff some concern. It was finally decided to include such a service whenever it was requested and was found to be available to help customers in emergencies and for economy energy interchange. This service has been provided in the Rate Schedule.

Dual Voltage Ties

The last comment was in regard to customers that have dual voltage electric ties with the Southwestern transmission system. It was suggested that these customers be billed at the higher voltage demand rate (lower price). Southwestern's response to this proposal is that transmission rates are charged based on the actual delivery voltages and the mere presence of a high voltage line does not establish a delivery voltage rate by itself. The Rate Schedule language has been revised to indicate that the delivery voltage will be specified by contract.

An order confirming and approving Rate Schedule TDC-2 on an interim basis is necessary for Southwestern to receive revenues from billings for transmission service performed after January 1, 1981.

Environmental Impact

Southwestern has reviewed the possible environmental impact of the rate adjustment under consideration and has concluded that because the rate increases do not exceed the rate of inflation in the period since the last rate increase, no environmental impact statement or environmental assessment is required under DOE guidelines for compliance with the National Environmental Policy Act of 1969 (NEPA).

Price Stability

Southwestern is a "government enterprise" within the meaning of the price standards of the President's Council on Wage and Price Stability. The rate increases approved herein comply with the operating margin limitation of these standards because the revenues will be only those necessary to cover Southwestern's costs and expenses.

Availability of Information

Information regarding this rate adjustment including studies, comments, and other supporting material are available for public review in the offices of the Southwestern Power Administration, 333 W. 4th, Tulsa, Oklahoma 74101 and in the Office of the Director of Power Marketing Coordination, 12th and Pennsylvania Avenue, N.W., Washington, D.C., 20461.

Submission to the Federal Energy Regulatory Commission

The Rate Schedule TDC-2 herein confirmed, approved, and placed in effect on an interim basis, together with supporting documents, will be submitted promptly to the Federal Energy Regulatory Commission for confirmation and approval on a final basis.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, effective January 1, 1981, the attached Rate Schedule TDC-2 for the Southwestern Power Administration, which supersedes and

replaces the Schedule TDC (Revised). The Rate Schedule TDC-2 shall remain in effect on an interim basis for a period of 12 months unless such period is extended or until the FERC confirms and approves this or a substitute rate on a final basis.

Issued at Washington, D.C., this 11th day of December, 1980.

Ruth M. Davis
Assistant Secretary
Resource Applications

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHWESTERN POWER ADMINISTRATION

RATE SCHEDULE TDC-2

Wholesale Rates for Transmission
and/or Displacement of Non-Federal power and Energy
Over the System of Southwestern

Effective:

As of January 1, 1981, and thereafter in accordance with Rate Order No. SWPA-7 of the Assistant Secretary for Resource Applications issued December 11, 1980.

Applicable:

In the marketing area of the Southwestern Power Administration (Southwestern) described generally as the States of Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas to wholesale power customers of Southwestern and other electric utilities whose transmission facilities interconnect with the transmission facilities of Southwestern. Non-federal power and energy will be, by contract, transmitted and/or displaced over those portions of the transmission and related facilities owned and operated by Southwestern (System of Southwestern) in which the Administrator, Southwestern, in his sole judgment, determines that transmission and transformation capacities are and will be available in excess of that required to market power and energy pursuant to Section 5 of the Flood Control Act of 1944 (58 Stat. 890).

Character and Conditions of Service:

Non-federal power and energy will be received into the System of Southwestern as scheduled by Southwestern, transmitted and/or displaced between two points on the System of Southwestern and delivered at the voltage level of the point or points of delivery as 3-phase alternating current, at approximately 60 hertz as specified by contract. Energy losses will be the responsibility of the customer and will be provided to Southwestern as specified by contract.

Transmission Demand:

The Transmission Demand for each point of delivery

for any month shall be the number of kilowatts equal to either—

(i) the maximum rate in kilowatts at which non-federal power and energy was delivered from the System of Southwestern at such point of delivery during any sixty-minute period during such month; or

(ii) the maximum Transmission Demand established at such point of delivery at any time during the preceding eleven months, whichever quantity is greater.

Interruptible Transmission:

A. Availability

Interruptible Transmission is transmission and transformation capability that could be utilized for economy energy interchange and in emergencies on a short-term basis of less than one month at such times and in such amounts as requested and as Southwestern determines to be available.

B. Interruptible Transmission Demand

The Interruptible Transmission Demand at each point of delivery for any day shall be the maximum rate of delivery in kilowatts during any sixty-minute period of such day.

Rates:

Compensation due Southwestern for the transmission and/or displacement over the System of Southwestern of non-federal power and energy shall be computed at the following rates:

(i) \$0.25 per kilowatt per month of Transmission Demand for the transmission and/or displacement of non-federal power and associated energy to point or points of delivery from the System of Southwestern at 138 kV or 161 kV.

(ii) \$0.40 per kilowatt per month of Transmission Demand for the transmission and/or displacement of non-federal power and associated energy to point or points of delivery from the System of Southwestern at 69 kV.

(iii) \$0.55 per kilowatt per month of Transmission Demand for the transmission and/or displacement of non-federal power and associated energy to point or points of delivery from the System of Southwestern at voltages of less than 69 kV.

(iv) 5% of (i), (ii) or (iii) amounts above per kilowatt per day for the Interruptible Transmission Demand at a given delivery voltage as applicable.

(v) \$0.0008 per kilowatt-hour for the transmission and/or displacement of non-federal energy without associated non-federal power to point or points of delivery from the System of Southwestern.

When power and/or energy is delivered at two or more voltages, the delivery voltage(s) shall be as specified by contract.

Minimum Monthly Bill:

The minimum bill for any month shall be equal to the

rate times the sum of the Transmission Demands for each point or points of delivery for such month. There shall be no minimum monthly bill for interruptible transmission service.

Adjustment for Power Factor:

An hourly power factor shall be maintained at each point of delivery of not less than 95% lagging. If during any hour in any particular month it is determined that at any point or points of delivery the hourly power factor at such point of delivery was less than 95% lagging, the Transmission Demand for such particular month for each such point or points of delivery shall be adjusted in accordance with the formula—

$$ATD = \frac{TD \times 0.95}{PF}$$

with the factors defined as follows:

ATD=The adjusted Transmission Demand for a particular point of delivery for any month during which the power factor was determined to be less than 95% lagging.

TD=The Transmission Demand for such month.

PF=The power factor determined for such month.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR
RESOURCE APPLICATION

In the Matter of:

Western Area Power Administration—) Rate Order
Colorado River Storage Project) No. WAPA-4
Power Rates

ORDER CONFIRMING, APPROVING, AND
PLACING INCREASED POWER RATES
IN EFFECT ON AN INTERIM BASIS
(December 23, 1980)

Pursuant to section 302(a) of the Department of Energy (DOE) Organization Act, 42 U.S.C. 7152(a), the power marketing functions of the Secretary of the Interior under the Reclamation Act of 1902, 43 U.S.C. 372 *et seq.*, as amended and supplemented by subsequent enactments, particularly by section 9(c) of the Reclamation Act of 1939, 43 U.S.C. 485h(c), and acts specifically applicable to the Colorado River Storage Project (CRSP), for the Water and Power Resources Service (Service) (formerly the Bureau of Reclamation), were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 FR 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm.

approve, and place in effect such rates on an interim basis, and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. This rate order is issued pursuant to the delegation to the Assistant Secretary and the rate adjustment procedures at 43 FR 12076 (March 23, 1978), as amended by 44 FR 7796 (February 7, 1979). The major topics included in the rate order are listed below.

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 National Environmental Policy Act (NEPA)
 Leavitt Act
 Price Stability
 Availability of Information
 Submission to the FERC

ORDER

BACKGROUND

Existing Rates

The increased rates which are the subject of this order supersede the following existing CRSP rates:

	Effective Date	Existing Rate	Increased Rate
Existing Rate Schedule UC-F2 for Wholesale Firm Power	June 1, 1977		
Demand charge, \$/kW-month		\$ 1.34	\$ 1.655
Energy charge, mills/kWh		3.4	4.0
Composite rate at 58.2- percent load factor in mills/kWh		6.55	7.89
Existing Rate Schedule UC-FP2 For Peaking Power	June 1, 1977		
Peaking capacity without energy in \$/kW-month		1.34	1.655

This order does not change the rates for the sale of non-firm power or for wheeling power over the CRSP transmission system.

Public Notice and Comments

P.L. 84-485 authorized the CRSP, including participating projects. This legislation requires that an annual report be made to Congress to show the status of the

project including "... the progress of return and repayment thereon, and the estimated rate of progress, year by year, in accomplishing full repayment..." To comply with this legislation, a power repayment study is made annually and its results are included in the annual report to Congress.

The FY 1977 power repayment study which was made for the 21st Annual Report showed that the existing power rate would be sufficient to pay annual expenses, but would not repay the power investment cost and the assistance needed to accomplish repayment of the irrigation features within the allowable time frames. A power rate increase of 43 percent (at 58.2-percent load factor) was found to be necessary to provide the required revenue. The result of this power repayment study was announced at a customer meeting on March 5, 1978.

An updated power repayment study was completed in August 1978. This study included some adjustments (primarily wheeling costs) to the 21st Annual Report Study and indicated that a 2.49 mill/kWh (38-percent) rate increase (at 58.2-percent load factor) would be necessary to provide the required revenue.

At the request of the Colorado River Energy Distributors Association (CREDA), meetings were held with CREDA representatives on December 19, 1978, January 19, 1979, and March 30, 1979. CREDA represents the majority of CRSP customers; however, all CRSP customers were formally invited to the CREDA meetings. At the first meeting, copies of a draft of the proposed power rate brochure were distributed to those present. At the three meetings, questions were asked by CREDA representatives and written answers were distributed at the meetings or mailed subsequently.

Federal Register notice 44 FR 19533 (April 3, 1979) announced the proposed CRSP rate adjustment and the public information and comment forums for public participation. This notice was subsequently amended by Federal Register notices 44 FR 24154 (April 24, 1979) and 44 FR 30759 (May 29, 1979) to add references to the PURPA standards and references to written comments. A press release was issued on April 3, 1979, to announce the proposed rate adjustment and the forums. On April 5, 1979, letters were sent to customers and other interested parties to announce the proposed rate adjustment and the forums and to transmit copies of the CRSP brochure dated April 1979, entitled "Proposed Power Rate Adjustment." Public information forums were held on the proposed rate increase in Phoenix, Arizona; Salt Lake City, Utah; and Denver, Colorado, on April 24, 25, and 26, 1979, respectively. At those forums numerous customers and other interested persons were in attendance. Procedures were reviewed, a summary of the brochure was presented, and all questions asked were answered at the forums or in writing before June 1, 1979.

In accordance with notices previously given, as referred to above, and reminder notices given by May 10, 1979, letters to customers and the June 6, 1979, press release,

a public comment forum was held in Salt Lake City, Utah, on June 26, 1979, with customers and other interested persons in attendance. Written comments were received until the close of the comment period on July 11, 1979.

Several of the customers' comments seemed to merit further consideration, and a revised repayment study was made in August 1979. By means of an August 22, 1979, letter to all customers, an August 24, 1979, Federal Register notice (44 FR 49785), and a press release dated August 24, 1979, announcement was made of another public forum to be held in Salt Lake City, Utah, on September 5, 1979. At this forum, a revised proposed rate increase (1.56 mills/kWh or 23.8 percent) was announced and copies of the August 1979 revised repayment study, the overhead projections used at the forum, and a September 5, 1979, brochure entitled "Revised Proposed Power Rate Adjustment" were distributed. Further comments were received through October 5, 1979.

Subsequent to the September 5, 1979, public forum, the Western Area Power Administration (Western) discovered that, contrary to a statement in the April 1979 rate brochure, the investment costs for all except three participating projects were at the January 1976 level and the costs of the three (Animas-La Plata, San Miguel, and West Divide Projects) were at the October 1967 price level. A second revision of the repayment study, with the three projects' costs indexed to the January 1976 level was made in February 1980. This study showed a need for a 1.69 mill/kWh, or 25.8-percent, rate increase, 2 percent higher than the previously revised proposed rate. A brief report showing the details of the study was sent to all customers by letter on February 12, 1980, (February 15, 1980, for CRSP customers in the Boulder City area) and the second proposed revision was published in the February 15, 1980, Federal Register (45 FR 10399) and was announced in a press release dated February 15, 1980. Customers were given an opportunity to comment until March 17, 1980.

Customer comments were again considered in preparing the proposed rate order which was issued on August 1, 1980, by the Assistant Secretary for Resource Applications and published in the Federal Register (45 FR 52900) on August 8, 1980. There was a request by a customer to make an oral presentation before the Assistant Secretary.

Therefore, a public comment forum was scheduled to be held on September 11, 1980, in Salt Lake City, Utah, and was announced in the Federal Register on August 21, 1980, (45 FR 55808). A notice of an extension until September 19, 1980, of the time that written comments could be submitted (extended from the September 8 date initially given) was published in the Federal Register on September 3, 1980, (45 FR 58407). The forum was held as scheduled. Comments received have been considered during preparation of the November 1980 revision of the power repayment study and of this rate order.

Project History

On April 11, 1956, the CRSP and participating projects were authorized by P.L. 84-485. By means of the four storage units authorized, the flow of the Colorado River is regulated in such a way that irrigation, municipal, industrial, and other water use developments in the Upper Colorado River Basin can be made while still maintaining water flows into the lower basin as required by the Colorado River Compact. Facilities have also been provided at the storage units for flood control, for recreation, and for other beneficial purposes. In order to maximize the use of water and to obtain revenues to assist in the repayment of the irrigation developments, power generating plants have been installed at three of the four storage units. A power generating plant has been installed on one of the participating projects and generating plants will be included on other participating projects where such developments are found to be feasible.

The table below lists the existing powerplants, with their installed capacity and dates of initial service.

	Installed Capacity MW	Inservice Date
CRSP		
Glen Canyon	950	Sept. 1964
Flaming Gorge Powerplant	108	Nov. 1963
Curecanti Unit— Blue Mesa Powerplant	60	Sept. 1967
Curecanti Unit—Morrow Point Powerplant	120	Dec. 1970
Curecanti Unit— Crystal Powerplant	28	Aug. 1978
Subtotal	1,266	
Participating Projects		
Seedskadee Project— Fontenelle Powerplant	10	May 1968
Grand Total	1,276	

Transmission facilities include a high-voltage transmission grid to deliver power to the established delivery points in the market area, to provide interconnections among the plants of the CRSP units and participating projects, and to interconnect with other existing Federal and utility systems within the market area.

DISCUSSION

Power Repayment Studies

General

The power repayment studies for the CRSP are prepared by Western with the cooperation of the Service. Basic river basin hydrology, water depletions, power generation, and project development data are among the

many items the Service contributes to the studies.

The power repayment studies are prepared in accordance with CRSP authorizing legislation and with DOE Order No. RA 6120.2 on Power Marketing Administration financial reporting, which basically adopted policy criteria originally established in the Department of the Interior's Manual, parts 730.3 and 730.4. The studies array historic income, expense, and investment to be repaid from power revenues, along with estimates for future years, and portray the annual repayment of power production and transmission costs of a power system, as well as nonpower costs assigned to power for repayment, through the application of revenues over the repayment period of the project. The studies show, among other items, estimated revenues and expenses year by year over the remainder of a project's repayment period, the estimated amount of Federal investment amortized during each year, and the total estimated amount of Federal investment remaining to be amortized. The studies do not deal with rate design.

The power repayment studies are also prepared in accordance with the Reclamation Project Act of 1939. As part of its marketing policy, Western strives to transmit and dispose of CRSP power and energy in such a manner as to encourage the most widespread use thereof at the lowest possible rates consistent with sound business principles. With the rate increase which is the subject of this Order, the power will be sold at the lowest possible rates in accordance with statutory mandate. Without the increase, the statutory requirements will not be met. Insofar as possible, the increase is in keeping with both sound business principles and statutory requirements.

The August 1978 Study

A repayment study made in August 1978 for fiscal year 1977 showed that the existing power rate is insufficient to pay within allowable time frames the costs assigned to the power function, mainly because of rapidly escalating construction and operating expenses. The study showed that in the time period between January 1974 - the price level date for the present rate - and January 1977, the total costs to be paid by power increased by about \$1,228 million. The August 1978 repayment study indicated that a power rate increase of about 38 percent (total cost of 9.04 mills/kWh at 58.2-percent load factor) would be needed to accomplish the repayment required by the project authorizing act.

The August 1979 Changes from August 1978 Study

The August 1978 power repayment study which resulted in the recommendation for a 2.49 mill/kWh (38-percent) rate increase was used in the April 1979 rate adjustment brochure entitled "Proposed Power Rate Adjustment." An analysis of customer comments and recommendations on this brochure resulted in Western adopting some of their recommendations. These changes are reflected in the August 1979 repayment study and are described in the September 5, 1979, brochure. The fol-

lowing is a discussion of the changes from the study in the April 1979 brochure:

Future Wheeling Expense

The repayment study in the April 1979 brochure included the estimated escalation of wheeling rates in future years. At the suggestion of the customers, Western reconsidered the matter and decided that the wheeling rates should not have been escalated. Elimination of the escalation reduced the future average annual wheeling cost for the 1978-2052 period from \$4,347,000 to \$3,071,000 and reduced the proposed power rate adjustment by 3.5 percent.

Application of Central Utah Project (CUP) and Seedskadee Power Revenues

The repayment study in the April 1979 brochure was based on deferring the application of CUP (Utah) and Seedskadee (Wyoming) power revenues to the repayment of the irrigation costs of participating projects in Utah and Wyoming until 50 years after the CUP and Seedskadee power inservice dates. The customers recommended that CUP and Seedskadee power revenues be applied to repayment of irrigation costs of Utah and Wyoming participating projects, respectively, as soon as the CUP and Seedskadee power costs are repaid. In comparing the early repayment studies with current studies, it was discovered that an unexplained change was made in 1973 and continued in subsequent years so that studies prepared from 1973 through 1976 have not been in compliance with the law on this point. Section 5(e) of P.L. 84-485 states that power revenues from a participating project should be applied to repayment of projects within the State and not be used to meet the requirements of participating projects in other States. Due to the express language in P.L. 84-485, Western adjusted the August 1979 repayment study to the original method, which retains CUP and Seedskadee power revenues to the credit of the States where the two projects are located. This reversion to the pre-1973 method of handling revenues from the participating projects reduced the proposed power rate adjustment by 7.3 percent.

Unidentified Future Transmission Investments

The repayment study in the April 1979 brochure included an estimated unidentified future transmission investment of about \$71 million in the 1981-1984 period. The customers recommended that the \$71 million be deleted. P.L. 84-485 authorized specific storage units, specific participating projects, and transmission facilities related to the foregoing, but did not specify any particular transmission facilities. In the 1958 repayment study and in all repayment studies since then, amounts have been included for unidentified transmission facilities. It was concluded that the historic policy, which was being followed by Western in the rate adjustment proposal, was a reasonable implementation of the law.

Western restudied the matter and decided that the \$71 million of unidentified transmission facilities should be deferred from the 1981-1984 period to the 1990-2020

period, with approximately one-seventh of the cost being placed in service every 5 years. The effect of this change was to reduce the proposed power rate adjustment by about 3.4 percent.

Summary of August 1979 Changes

A summary of the changes made in the August 1979 study as compared to the August 1978 study is tabulated below:

Item	Decrease in Proposed Rate Adjustment
Eliminate escalation of future wheeling expense.	3.5 percent
Apply CUP and Seedskaadee power revenues to Utah and Wyoming as in repayment studies prior to 1973.	7.3 percent
Defer unidentified future transmission investments from 1981-1984 period until 1990-2020 period.	3.4 percent
TOTAL DECREASE	14.2 percent

The result of the above was to increase the existing rate by 1.56 mills/kWh (23.8 percent) instead of by the 2.49 mills/kWh (38 percent) stated in the April 1979 brochure.

February 1980 Changes from the August 1979 Study

Costs for the Animas-LaPlata, San Miguel, and West Divide Projects

Subsequent to the September 5, 1979, forum, Western discovered that, contrary to a statement in the April 1979 rate brochure indicating that all costs were at 1977 price levels, the investment costs of all except three of the participating projects were at 1976 price levels. The costs of the three projects (Animas-La Plate, San Miguel, and West Divide) were at 1967 price levels.

The investment costs of these three projects were indexed to January 1976 price levels and another revised repayment study was run in February 1980. This second revision showed that an overall rate increase of 1.69 mills/kWh (from 6.55 mills/kWh to 8.24 mills/kWh) or 25.8 percent was needed, 2 percent higher than the previously revised proposed rate.

November 1980 Changes from February 1980 Study

Deletion of Unidentified Future Transmission Investments

During a September 11, 1980, public hearing concerning the then proposed rate order, commenters asserted that Department of Energy Order RA 6120.2, which was adapted from 730 DM 4 of the Department of the Interior Manual, limits the period of time during which future estimates of power system costs may be modified to reflect changing conditions, such as transmission additions, to a cost evaluation period which is normally 5 years. Deferring the unidentified transmission facilities to the 1990-2020 period placed them outside the normal cost evaluation period. Consideration was given to the possibility of moving the unidentified transmission fa-

cilities back into the 1981-1984 period and, based on developments since the FY 1977 studies were initially prepared, identifying them. However, such use of later developments would open the studies to a multitude of other developments and prolong the rate adjustment efforts.

As analyzed in more detail in a later section of this rate order, Order No. RA 6120.2 allows for exceptions "specifically approved by the Secretary" or "authorized by statute." The inclusion of unidentified transmission during the 1990-2020 period was one of these exceptions. However, since it is the practice of the Secretary to market power at the lowest possible rates consistent with sound business practices, weight was given to the policy underlying the 5-year cost evaluation period in this instance. A decision was made to delete the unidentified transmission facilities. Transmission facilities will be identified in the next repayment study, however, and will be considered in the evaluation of project costs and revenues in the future. The effect of this deletion is to reduce the rate by 5.3 percent, to a 20.5 percent (1.34 mills/kWh) increase.

Repayment Issues

Other public comments were received which were critical of a number of assumptions made in the repayment study. The areas of comment are discussed below.

Inclusion of Future Projects in Repayment Study

The primary thrust of a number of the public comments relating to the repayment study revolved around whether or not all participating projects which have been authorized by Congress should be included in the repayment study. This concern has apparently emerged due to the amount of time which has elapsed between authorization and construction.

Several customers suggested that the proposed rate increase be based on a repayment study which excludes the costs of participating projects not yet in service or nearing completion, and that future or "stepped" rate increases be made as the projects reach or approach the in-service dates. It is clear, however, from the provisions of the Act, the legislative history of P.L. 84-485 which established CRSP, and from the first repayment study—which provides a contemporaneous interpretation and guide for repayment procedures—that it was the intent of Congress that current rates be based on the inclusion of all authorized participating projects in CRSP repayment studies. The Western Area Power Administration's Office of the General Counsel has issued a legal memorandum supportive of the present ratemaking methodology. The inclusion of all authorized participating projects is legislatively and administratively proper.

The appropriateness, within legal restraints, of including each of the participating projects has been considered. Only one authorized participating project has ever been deauthorized. The Pine River Extension was authorized by Congress on April 11, 1956, by P.L. 84-485, and was deauthorized by Congress on September 30, 1968, by

P.O. 90-537. No costs have been included for the Pine River Extension.

The status of four other participating projects, although still authorized, is subject to question. The entire LaBarge Project and the irrigation development on the Seedskadee Project have both been declared by the Bureau of Reclamation to be indefinitely deferred and Congress has been so informed. Costs included for these two projects are limited to sunk costs based on their indefinitely deferred status. More recently, President Carter has recommended deauthorization of the Fruitland Mesa and Savery-Pot Hook Projects; however, no legislative action has been taken to deauthorize either of the projects and, although no funds have been expended on them since the President's recommendation, they have not been declared to be indefinitely deferred. Except for the delay, their status remains as it was before the President's recommendation, and their costs have accordingly been included. A more complete summary of the status of these four projects is given below.

LaBarge Project

The project was authorized by the Congress on April 11, 1956, by P.L. 84-485. On February 2, 1961, the Regional Director, U.S. Bureau of Reclamation, Salt Lake City, Utah, wrote the Commissioner of the Bureau of Reclamation recommending that construction not be undertaken. The Commissioner concurred by letter of February 27, 1961, in the recommendation "...that construction of the project not be undertaken at this time..." In the CRSP 9th Annual Report to Congress for FY 1965, the Bureau of Reclamation stated that construction had been deferred indefinitely, as suggested in the Senate Subcommittee Appropriation Hearings for FY 1962, page 216. Tables of repayment data for the LaBarge Project follow the discussion of the Savery-Pot Hook Project.

Seedskadee Project

The project was authorized by Congress on April 11, 1956, by P.L. 84-485. Congressional hearings on the Riverton and Eden Projects in 1962 brought to light that serious financial and economic problems were encountered by farmers on these high-altitude irrigation projects. As a result of these hearings, the Commissioner of the Bureau of Reclamation issued a stop order on May 21, 1962, suspending construction of irrigation features of the Seedskadee Project until a review of Wyoming reclamation projects could be accomplished. The Secretary of the Interior on August 10, 1962, appointed the Wyoming Reclamation Projects Survey Team to analyze problems on Wyoming projects and recommend possible solutions. One of the recommendations made by the survey team was that a development farm be established on the Seedskadee Project. Data collected from the operation of the development farm resulted in the conclusion that only 34,000 acres of the original 58,000 acres were suitable for irrigation, that even the 34,000 acres would be marginally feasible, and that the developed project

water supplies should be made available for municipal and industrial (M&I) and other purposes. As a result of the investigations, and because of the desire of the State of Wyoming to purchase Seedskadee water for M&I purposes, the United States sold the State all the storage space in the Fontenelle Reservoir excluding the last 65,000 acre-feet. The State was given the first right of refusal to the last 65,000 acre-feet upon notice of its availability for M&I purposes. All the foregoing is documented in the October 8, 1973, letter from the Assistant Secretary of the Interior to the President, with copies to the President of the Senate, to the Speaker of the House, and to the Chairman of the Senate and House Committees on Interior and Insular Affairs.

In December 1974, the Bureau of Reclamation in Salt Lake City, Utah, prepared a cost allocation report on the Seedskadee Project. After review by various offices of the Bureau of Reclamation and by the Wyoming reclamation representative, the report was submitted to the Commissioner of the Bureau of Reclamation for use in a report to the Congress as required by section 6 of P.L. 84-485. The report stated that "Irrigation development has been indefinitely deferred..." and established revised repayment schedules. Tables of repayment data for the Seedskadee Project follow the discussion for the Savery-Pot Hook Project.

Fruitland Mesa Project

The project was authorized on September 2, 1964, by P.L. 88-568. The Definite Plan Report was approved October 9, 1967, and a repayment contract with Fruitland Mesa Water Conservancy District (District) was validated September 29, 1969. As a result of new water supply studies and changes in plan formulation, the Definite Plan Report and contract with the District were in the process of revision in early 1977. On April 18, 1977, the President recommended deauthorization of the project. No action has been taken to deauthorize the project and the project has not been declared to be indefinitely deferred, although no funds have been expended on the project since that time. Tables of repayment data for the Fruitland Mesa Project follow the discussion of the Savery-Pot Hook Project.

Savery-Pot Hook Project

The project was authorized on September 2, 1964, by P.L. 88-568. The Definite Plan Report was approved December 2, 1971. As a result of changes in plan formulation, the Definite Plan Report was in the process of revisions in early 1977. Repayment contracts with the Pot Hook and Little Snake Water Conservancy Districts were also being negotiated in early 1977. On April 18, 1977, the President recommended deauthorization of the project. No action has not been taken to deauthorize the project and the project has not been declared to be indefinitely deferred, although no funds have been expended on the project since that time. Tables of repayment data for the LaBarge, Seedskadee, Fruitland Mesa, and Savery-Pot Hook Projects follow.

LaBarge Project

<u>1964</u>		<u>1965</u>		<u>1977</u>	
Data before deferment		Data after deferment		Repayment study	
Irrigation repaid by:		Irrigation repaid by:		Irrigation repaid by:	
Irrigators	250,000	Irrigators	0	Irrigators	0
Apportionment		Apportionment		Apportionment	
(power)	1,501,000	(power)	136,000	(power)	136,000
Others	0	Others	0	Others	0
Municipal and Industrial	0	Municipal and Industrial	0	Municipal and Industrial	0
Power	0	Power	0	Power	0
Nonreimbursable	65,000	Nonreimbursable	86,000	Nonreimbursable	86,000
Total	1,816,000	Total	222,000	Total	222,000

Seedsakadee Project

<u>1964</u>		<u>1965</u>		<u>1977</u>	
Data before deferment		Data after deferment		Repayment study	
Irrigation repaid by:		Irrigation repaid by:		Irrigation repaid by:	
Irrigators	7,300,000	Irrigators	0	Irrigators	0
Apportionment		Apportionment		Apportionment	
(power)	39,672,000	(power)	1,428,000	(power)	1,228,000
Others	402,000	Others	411,000	Others	411,000
Municipal and Industrial	908,000	Municipal and Industrial	12,310,000	Municipal and Industrial	12,310,000
Power	3,574,000	Power	3,574,000	Power	3,574,000
Nonreimbursable	7,724,000	Nonreimbursable	16,586,000	Nonreimbursable	16,984,000
Total	59,580,000	Total	34,309,000	Total	34,507,000

Fruitland Mesa Project

<u>1977</u>		<u>1978</u>	
Repayment Study		22nd Annual Report	
Irrigation repaid by:		Irrigation repaid by:	
Irrigators	3,790,000	Irrigators	3,790,000
Power	80,256,000	Power	80,256,000
Others	181,000	Others	181,000
Municipal and Industrial	0	Municipal and Industrial	0
Power	0	Power	0
Nonreimbursable	4,373,000	Nonreimbursable	4,163,000
Total	88,600,000	Total	88,390,000

Savery-Pot Hook Project

1977		1978	
Repayment Study		22nd Annual Report	
Irrigation repaid by:		Irrigation repaid by:	
Irrigators	5,086,000	Irrigators	5,086,000
Power	66,630,000	Power	66,630,000
Others	869,000	Others	869,000
Municipal and Industrial	0	Municipal and Industrial	0
Power	0	Power	0
Nonreimbursable	2,315,000	Nonreimbursable	2,340,000
Total	74,900,000	Total	74,925,000

The total cost of all the participating projects is nearly \$2,553 million, and the amount to be repaid from power revenue is nearly \$1,090 million.

Effect of Elimination of Projects Discussed Above

As discussed later in this order, section 5(e) of P.L. 84-485 requires the apportionment of certain revenues among the four Upper Colorado River Basin States of Colorado, New Mexico, Utah, and Wyoming. The requirements of projects in one of the four States will determine the total revenue needed for apportionment. For the studies on which this rate increase is based, the controlling State which determines the total revenue needed for apportionment is Colorado. Since some of the projects discussed above are in Colorado, their elimination would reduce the total revenue required. However, the elimination of projects in Colorado would result in Utah becoming the controlling State which determines the total revenue needed for apportionment, and would result in a reduction of only about 2 percent in the amount of increase needed. For reasons already discussed, the projects have not been eliminated.

Cost Evaluation Period

A number of customers raised the issue of whether 730 DM 4 of the Department of the Interior Departmental Manual (now also Department of Energy Order No. RA 6120.2) should not limit the analysis of future irrigation costs associated with CRSP to a maximum of about 5 years. Order No. RA 6120.2 does not conflict with the current CRSP ratemaking methodology for a number of reasons. The order provides, in the first paragraph, for exceptions "specifically approved by the Secretary" or "authorized by statute." The CRSP Act sanctions the departure from the 5-year limitation, as does the longstanding interpretation of the administrative agencies charged with the sale of CRSP power. Even if the "authorized by statute" exception did not exist, the execution of this rate order demonstrates, as a matter of administrative policy, the approval of the current CRSP ratemaking methodology. This policy decision is based upon the Reclamation policy of irrigation assistance, past admini-

strative practice, and the comprehensive purpose of the CRSP as a whole. Furthermore, the provisions in Order No. RA 6120.2 relating to a cost evaluation period apply only to power facilities. This is indicated by the second sentence of paragraph 10(k) which specifically refers to power facilities. The subject of future irrigation investment is not covered and therefore a determination with respect to these future investments must be made on a project-by-project basis.

Federal projects Use Repayment Basis to Set Revenue Levels

Further comments raised the issue of whether the Federal Energy Regulatory Commission restrictions on the inclusion of the costs of future facilities in ratesetting for private utilities would restrict FERC approval of the CRSP rates.

Generally, the FERC does not allow the inclusion of construction work in progress (future facilities) in setting current rates. As one of the commentators stated, "The basis of the Commission's decisions along these lines is that a utility's plant facilities should not be paid for by the utility's ratepayer through the utility's rates until such facilities become 'used and useful' to the ratepayer." The CRSP is not an electric utility as defined in the Federal Power Act, but rather is a reclamation water project to which hydroelectric generation has been added to assist in repaying for certain of the water features. Irrigation projects and salinity control are not "used and useful" to power customers per se. It is essential that costs of such features to be paid by power should be spread as evenly as possible over all power users for the entire life of the project, while at the same time being sure that all investments are repaid by the end of their respective repayment periods.

Further, Federal power rates are required by law to be established on a repayment basis. The repayment studies that set revenue level requirements show that annual

operating costs will be recovered in the year in which they are incurred and that all investment will be amortized within a reasonable period of years, which has been determined to be 50 years in most cases. This analysis includes future revenues and costs—in this case to the year 2052—as well as historical revenues and costs. The methodology differs substantially from the ratesetting approach based on cost-of-service studies incorporating depreciation as used in the private utility sector.

Benefits Versus Costs

Some customers questioned whether the benefits of unbuilt projects would exceed the costs and/or outweigh the environmental consequences.

At one time, all authorized unbuilt projects had benefit-cost analyses indicating that the benefits exceeded the costs. Shortly before construction begins, new benefit-cost analyses and environmental impact statements will be made, based on the final plan adopted. It is not possible at this time to accurately predict what the final results will be.

Apportionment of Revenues

In the repayment studies, revenues in the Upper Colorado River Basin (Basin) fund for irrigation assistance to authorized participating projects are apportioned to the States by the percentages specified in section 5(e) of P.L. 84-485. This results in a credit to some States in excess of that required for currently authorized participating projects.

Power customers refer to this excess as “surplus surplus” and, to prevent it, advocate application of the revenues to repayment of each participating project feature as the feature repayment comes due. The power customers and Western made repayment studies based on the originally proposed rate adjustment, which show that the method advocated by the customers would have reduced the 38-percent rate adjustment to about 19.8 percent. Western made a similar study using the 25.8-percent increase as a base, and it showed that the method advocated by the customers would reduce the rate adjustment from 25.8 percent to about 15.1 percent.

It is clear that this “surplus surplus” will accrue in the future because P.L. 84-485 requires that certain revenues in the Basin fund are to be apportioned among the States for repayment of the participating projects.

The law prohibits the use of revenues apportioned to any State from being used in any other State without the consent of the legally constituted authority of the State to which they are apportioned.

Western met with the governors of the four Upper Basin States to inform them of the need for the rate adjustment and the appropriate provisions of the law. Subsequently, on October 2, 1979, the governors of the affected States adopted the recommendation of the September 17, 1979, resolution passed by the Upper Colorado River Commission that they “...support the position that the proposed power rate adjustment for the marketing of

Colorado River Storage Project power be established in accordance with the requirements of Public Law 84-485, as amended, to achieve the purposes of the Act....” While the adoption of this resolution does not rule out the possibility of a State with surpluses allowing those surpluses to be used in another State, it does preclude the use of such a possibility in the present rate adjustment.

Energy Losses

Several customers questioned using energy losses of 7 percent of the energy delivered at designated delivery points and suggested that it should be about 3 to 5 percent instead. CRSP's average percent loss of energy delivered to designated delivery points from 1972 through 1978 (excluding the drought year of 1977) is 7.38 percent; therefore, the 7 percent as used in the rate study seems reasonable.

Diversity Versus Capacity Losses

Some customers suggested that diversity may exceed capacity losses and that this should be analyzed. Western looked at the 1972-1978 period (excluding the 1977 drought year) and found that, in some of the years, the diversity exceeded losses and in other years, the diversity was less than losses. On the average for the 6-year period, the diversity exceeded the losses by 22 MW in the summer and 2 MW in the winter. With the exclusion of the summer of 1976 during which there was an extraordinarily high diversity (in addition to excluding the 1977 drought year), the diversity varied between 35 MW higher and 30 MW lower than losses. On the average, the diversity exceeded the losses by 8 MW in the summer and 2 MW in the winter. In view of the foregoing, it appears that the assumption of diversity equaling capacity losses is reasonable.

Depletions

Some customers suggested that the water depletions used in the power repayment study are too high because they include depletions for future participating projects and also for unidentified developments.

The customers also commented that all possible M&I revenues from the sale of water (i.e., depletions for M&I use) are not included, and that, if included, the required power rate would decrease.

As stated elsewhere in this order, P.L. 84-485 requires that the study must include all authorized water developments which are components of the CRSP. The water depletion schedule has been developed by the Water and Power Resources Service, and incorporates the reasonable assumption that the pressures of a growing population will eventually result in water developments utilizing each State's entitlement of the flow of the Colorado River. These developments may not necessarily be Federal projects, but anticipated water demands indicate that the water will be used. The Water and Power Resources Service's schedule appears to be a reasonable basis to use for the power repayment study, recognizing

that any prediction about the future is speculative at best. In any event, subsequent power repayment studies will reflect updated depletion schedules based on the more current information.

Because of uncertainties about the outcome of the President's recommendation to deauthorize the Fruitland Mesa and Savery-Pot Hook Projects, depletions for those two projects were omitted from the FY 1977 hydrological study, which later was used as the basis for the CRSP power repayment study. These projects should not have been deleted because, as explained elsewhere in this order, they have neither been deauthorized nor declared to be indefinitely deferred. However, the depletions used in the hydrology study included unidentified depletions which, except for the one year 1990, exceeded the magnitude of the depletions for the Fruitland Mesa and Savery-Pot Hook Projects. Therefore, there would have been no change in the power rate even if depletions for the Fruitland Mesa and Savery-Pot Hook Projects had been identified in the study.

M&I revenues from storage units in excess of costs allocated to M&I are apportioned to the States for irrigation assistance. However, M&I water users of participating projects pay only their allocated costs and do not assist in the repayment of the irrigation allocation; therefore, future depletions caused by M&I water use will not result in extra revenue to reduce the power rate.

Replacements

The Customers suggested that, since replacement factors used in the rate study were developed in 1969, replacement cost estimates should be reevaluated. It is true that the factors for replacements were developed in 1969. However, these factors were based on the historical service lives of the equipment; and while updated experience may modify some of the service lives, it is unlikely that there would be a significant change. Western and the Service are currently in the process of updating the replacement factors, and any revisions will be reflected, when available, in future power repayment studies.

Power Revenue Assistance to Irrigation Projects

Some customers questioned why CRSP power revenues are used to provide assistance for irrigation projects, whereas Parker-Davis and Boulder Canyon Project power revenues are not.

Pursuant to enabling legislation, CRSP power revenues must provide assistance for irrigation projects, whereas enabling legislation for Parker-Davis and Boulder Canyon Projects does not provide for such assistance. The power rates proposed for each project must be adequate to effect repayment as contemplated by its authorizing legislation. Such legislation does not always allow uniformity among the projects as to what costs must be paid from power revenues and in methods for

determining power rates. While power revenues from the Parker-Davis Project are not used for irrigation assistance, they are used to repay investment in non-interest-bearing electrical facilities used to support irrigation on several projects, as well as to repay certain costs associated with the Mexican Water Treaty. Revenues from the Boulder Canyon Project are not used to repay costs of irrigation projects. Repayment on both projects is in accordance with authorizing legislation, and Western has made no changes in either study.

M&I Water Rates and Irrigators' Ability to Repay

Some customers suggested that M&I rates should be raised when power rates are increased and that the irrigators' calculated ability and obligation to repay should also be revised at the same time. The M&I rate for water from mainstem CRSP reservoirs was set by Service policy to recover construction costs allocated to M&I water plus contingencies and operation and maintenance (O&M). The rates are fixed for the term of the contracts. Upon the expiration of these contracts, the need for changing the rates will be explored. The M&I rates for water from participating projects are set to repay the costs allocated to M&I plus O&M. All contracts for irrigation water on participating projects require the water users to repay a fixed amount of investment plus operation, maintenance, and replacements (OM&R). The irrigators and participating projects' M&I water users automatically pay any increased costs of OM&R.

Reserves

One of the customers suggested that the amount assumed for reserves is too high. The reserve assumed for the repayment study was 10 percent of the load, a percent factor that has been used in previous repayment and other studies. The Western Systems Coordinating Council (WSCC) power supply design criteria recommend that reserve capacity should meet or exceed the sum of the capacity associated with the two largest risks or the largest risk plus 5 percent of load. A comparison between the reserves, as used in the CRSP rate study and the WSCC standard for the year 1990, is as follows:

Rate study reserves	— 144 MW
WSCC standard	— 216 MW

From this comparison, it appears that the reserves as used in the repayment study are not too high.

Extraordinary O&M Expenses

One customer suggested that the extraordinary O&M expenses for FY 1979 in the power repayment study should be amortized over a reasonable period of years rather than being completely paid for in the year in which they occur. The extraordinary O&M expenses of \$800,000 are for spillway tunnel repairs at Flaming Gorge and for road construction at Glen Canyon.

Without any rate increase, revenues are available in

1979 to pay the extraordinary O&M expenses in that year. If the revenues are not applied to the extraordinary O&M expenses, they would be applied toward repayment of other investments bearing the same interest rate (2.875 percent) as would be applicable to the unpaid extraordinary O&M expenses. The \$800,000 expense could be treated either way with no effect on the rate increase.

Present Status of CRSP Repayment

Some customers stated that the CRSP is \$87 million ahead of its required repayment of Federal investment. However, the \$87 million is the total amount through FY 1977 that has been applied to repayment of storage units' investment costs which are allocated to power. CRSP generally has 50 years in which to repay each investment, but cannot wait until the last year for each investment and then repay the whole thing. This would cause sudden and severe changes of rates. Instead, CRSP spreads the repayment over the 50 years (paying highest interest-bearing investments first to the extent possible) in such a way as to maintain as level (and low) rates as possible. Based on CRSP repayment criteria and the power repayment study, repayment of Federal investment is behind instead of ahead of schedule.

Repayment of Salinity Control Construction Costs

Some customers recommended that, instead of assuming in the study that the interest-free salinity control construction costs would be repaid in 50 equal annual installments, the study should have been based on deferring such repayment until interest-bearing costs are repaid. This would eliminate about \$3 million in interest payments.

P.L. 93-320 provides that, among other things, the portion of the salinity control costs allocated to the Basin will be paid by CRSP power revenues, and furthermore that "...the Secretary is authorized to make upward adjustments in rates...as soon as practicable and to the extent necessary to cover the costs of construction, operation, maintenance, and replacement of units... Provided, That revenues derived from said rate adjustments shall be available solely for the construction, operation, maintenance, and replacement of salinity control units in the Colorado River Basin...."

In early 1976, the then Bureau of Reclamation sought advice from the Regional Solicitor of the Department of the Interior on this matter. By a memorandum dated April 13, 1976, the Solicitor advised the Regional Director that in view of the provisions of P.L. 93-320 quoted above, the repayment of salinity control construction costs could not legally be delayed until after noninterest-bearing costs are repaid. Therefore, CRSP repayment studies made since 1976 have included repayment of salinity control construction costs in 50 equal annual installments.

Upgrading the Generators at Glen Canyon Powerplant

Some customers suggested that the additional capacity at Glen Canyon Powerplant due to upgrading the genera-

tors should have been included in the February 1980 repayment study and that, based on data from power repayment studies for the CRSP 23rd Annual Report (after FY 1979), the sale of such added capacity would have increased the revenues by more than twice those needed to counteract the increased costs of the three participating projects added in the February 1980 revised repayment study.

The power repayment studies for the proposed rate increase have for the most part been based upon conditions that existed as of the end of FY 1977, when the CRSP 21st Annual Report was prepared. At that time, maintenance funds were budgeted for future replacement of Glen Canyon generator stator windings and rotor pole piece collars because of normal wear and tear. However, the Service had not investigated the matter fully enough to determine whether or not the units could be uprated. Commenters pointed out that the 21st Annual Report contains this statement: "An award was made April 14, 1977, for stator windings on two existing generators at the Glen Canyon Powerplant. Work was initiated on September 28, 1977, on Unit 7. The new windings will increase the generator capacity of each unit by 25 megawatts." Western has been unable to locate either the source or the basis for the stated 25 megawatt increase for each unit. The power repayment study included in the 21st Annual Report does not include the claimed additional capacity.

When the studies for the CRSP 23rd Annual Report were made, the Service had made further investigations and operational tests, and felt that with some additional modifications it was reasonable to assume the uprating could be realized. Therefore, the repayment study for the 23rd Annual Report included increased sales due to uprating. It should be noted that, taking the planned uprating into account as well as other changes between 1977 and 1979, the 23rd Annual Report shows the need for a rate increase greater than the 20.5 percent promulgated by this order.

Revenues from Capacity Above Lower Quartile

Revenue from future capacity sales used in the power repayment study is based on capacity available under lower quartile water conditions. It was suggested that capacity during years when water conditions exceed the lower quartile could be sold and that the effect of this should be included in the rate determination.

Power repayment studies prior to the FY 1976 studies included capacity revenues only from the long-term dependable capacity (capacity available during the most adverse water year). However, in recognition of the fact that capacity above that available under adverse water conditions is almost always available, and is usually sold, the present study is based on sales of capacity under lower quartile water conditions. Consideration was given to using capacity available under average water conditions based on the theory that half the time there would be more capacity available, and half the time there

would be less capacity available, and that all the capacity available would be sold. A comparison of the historical capacity offered for sale with the amount sold indicates that there has generally been a market for the excess capacity. However, in order to achieve capacity revenues which over the long-term average the same as capacity sales under average water conditions, all the capacity available would have to be sold every month. To assume that this could be done would be imprudent — there are too many possible conditions which might prevent this from happening, such as the inability to locate a purchaser because of market conditions, or because of the inability of the power system to produce and deliver power due to maintenance of powerplants and/or transmission facilities. The use of lower quartile capacity is therefore both reasonable and prudent.

Historically, all revenues from capacity sales are included in the study.

Amortization of Parker-Davis Project Facilities

Some customers suggested that the construction costs of the portion of the Parker-Davis Project facilities paid for by CRSP revenues be repaid in the same manner as the construction costs of CRSP facilities, instead of the CRSP paying Parker-Davis Project a uniform annual amortization amount.

By Contract No. 14-06-304-1548 between the then Regions 3 and 4 of the Bureau of Reclamation (now Water and Power Resources Service), agreement was made that the CRSP would pay the Parker-Davis Project for construction repayments in equal annual amortization amounts based on 3-percent interest and a 30-year repayment period. The contract has been transferred to Western, and the contract provisions are used to develop the payment used in the CRSP repayment study. Since the 3-percent interest is higher than the interest rates of CRSP facilities, except central Utah, application of the general rules for CRSP repayment; i.e., repay highest interest-bearing costs first, would probably show a small reduction in the magnitude of the CRSP power rate increase needed. However, the change would be very minor, since the total construction cost involved is less than \$3 million and the 3-percent interest rate is only slightly higher than the 2 7/8-percent interest rate of the major portion of CRSP investments.

Increase in Investment Versus Increase in Required Irrigation Assistance

One group of customers pointed out that, in the February 1980 power repayment study, the investment costs of the Animas-La Plata, San Miguel, and West Divide participating projects increased by only 61 percent, whereas the required irrigation assistance to the aforementioned projects from power and M&I revenues increased by 80 percent. The customers claimed that the disproportionate increase of irrigation assistance as compared to investment is improper.

The reason why the required irrigation assistance increased by a greater percentage than did the investment costs is that the revised costs shown in the repayment study are based partly on cost indexing and partly on revised plan formulations for the participating projects. The irrigators' ability to repay did not increase in proportion to the cost increases. Thus, these changes result in the irrigation assistance being increased accordingly.

Rate Design Issues

Description of the Design of the Rates

Much of the CRSP cost paid by power revenues, such as aid to irrigation, is not normally considered to be a cost of service in the usual sense. The CRSP power is sold at the rate required to pay operating costs and to recover the costs specified in P.L. 84-485 and in P.L. 93-320. The rate schedule also has a provision that unauthorized overruns shall be billed at 10 times the base rate. Although this provision is intended as an incentive for the customer to find supplemental power suppliers, it may encourage energy conservation to some minor extent.

The CRSP firm-power rate includes a capacity component and an energy component. A cost classification analysis was made by assigning various costs to the two components. The main costs assigned to the capacity component include: power capital and replacement investments, interest on power investments, irrigation investments of the storage units to be repaid by power revenues, and one-half the irrigation aid to participating projects. The major costs assigned to the energy component include: O&M, firming-energy purchases, power wheeling, salinity construction costs, and one-half the irrigation aid to participating projects. Results of the cost classification analysis indicated that revenues from the sale of capacity and energy should be given approximately equal weight.

A low demand rate would probably benefit those customers who purchase CRSP peaking capacity, but could be detrimental to project irrigation pumpers. In consideration of the cost classification and in order to minimize discrimination among types of power users, it is felt that the new power rate should be based on equal revenues from capacity and energy sales at 58.2-percent load factor. The first rate established in 1962 also was on this basis. The energy component has been rounded off to the nearest 0.1 mill/kWh and the capacity component to the nearest 0.5 cent/kW-month, resulting in a revised proposed CRSP rate of 4.0 mills/kWh and \$1.655/kW-month. Because of rounding in this fashion, the revised repayment study of November 1980 indicated a small surplus (approximately \$4.0 million) in power revenues above the requirements of the law by the critical year 2046.

Adjustment Provision For Purchased Energy Costs

During the April 1979 public information forums Western announced that it was considering the possi-

bility of including, in the new rate schedules, provision to pass through purchased power costs. Such a provision was under consideration because during periods of adverse hydro conditions large purchases are required, and funds for such purchases can be quickly depleted without some means of quick (i.e., monthly) recovery. However, such a provision has not been included for the following reasons:

1. Purchases are often made in the autumn and winter as a hedge against the possibility of poor water conditions in the following spring and summer. It is often late summer before the extent to which such purchases were necessary for firming is known. Purchases may turn out to have been in excess of firming requirements and, to that extent, are available for other uses, such as oil conservation sales. For this reason the purchased power costs cannot be passed on at the time they are made and at the time when the revenues are needed.

2. When firming purchases are necessary for the CRSP, they are also apt to be necessary for the Parker-Davis Project, which is downstream from the CRSP. This project purchases its firming requirements from the CRSP, further complicating the determination on a monthly basis of just how much of the power purchased by the CRSP is for firming the supply to and at the cost of its own firm-power customers.

3. The power repayment studies on which the rate increase is based have been prepared using average hydro conditions for energy production, and assume that revenues from the sales of surplus energy in better-than-average water years will offset the cost of the purchase of firming energy during poorer-than-average water years. Implementation of a passthrough provision for purchased power costs would upset this balance.

Alternative Power Rates and Conservation

Some customers stated that the repayment study implies that the rate is being increased because of conservation desires or to bring it closer to alternative rates. As stated in the rate brochures, in presentations at forums, and in all written and verbal answers to questions, the level of the rate increase determination is based on payment of costs and investments and was not influenced by alternative power rates or conservation desires. Rather, any comparison with other power rates in the general area is to demonstrate that the proposed cost-based rates are not in excess of market value. Were project costs such that required rates would be in excess of market value, the rates would be based on the market value and the project would operate at a loss until such time as market value increased sufficiently to allow the rates to be increased to recover costs, including repayment of the deficit with interest.

Charges for Wheeling Over Parker-Davis Project System

Some customers who receive CRSP power over the Parker-Davis Project system content that the CRSP power rate should include the cost of wheeling over that

system so that they would not have to pay for such wheeling (except as a component of the CRSP rate for power). The present CRSP marketing criteria, which were adopted and published in the Federal Register on February 9, 1978, after consultation with the customers, include a provision that any wheeling charges over other project systems such as the Parker-Davis Project system are to be paid by the customers receiving the power. The current Parker-Davis Project rate increase proposal includes provisions for such a rate, and, under the criteria, the customers receiving the power over that system must pay the costs.

Phased or Stepped Rate Increases

Some customers recommended that the proposed rate increase, if adopted, be phased or stepped over a period of years. To try to avoid confusion on this issue, Western has distinguished between phased increases and stepped increases. Western considers a phased increase to be one in which the rate is increased at regular intervals, unrelated to costs, until the final rate is in place. This was done for the Rio Grande Project because of the magnitude of the increase (from 8.15 mills per kilowatthour to over 16 mills per kilowatthour). The magnitude of this CRSP rate increase is much less and use of a phased increase is not warranted.

Western considers a stepped increase to be one in which the rate is increased based on and at the time of anticipated significant future additions to the system. The arguments for and against stepped increases are the same as those which are discussed in the second paragraph under the heading "Federal Projects Use Repayment Basis to Set Revenue Levels" earlier in this order. The anticipated significant future additions for the CRSP are not power features, but rather are irrigation features, and, as discussed in the paragraph already cited, it is essential to spread the costs of such features among as many power customers over as long a period as possible.

Applicability of the Public Utility Regulatory Policies Act of 1978 (PURPA)

The standards set forth in the PURPA, 16 U.S.C. 2601 *et seq.* are not applicable to sales that are for resale, and are not currently applicable to CRSP sales that are not for resale because CRSP has not had such sales in excess of 500 million kWh in any year. Nonetheless, each of the 11 standards was considered and briefly discussed in the April 1979 brochure entitled "Colorado River Storage Project and Participating Projects — Proposed Power Rate Adjustment" and interested parties were given opportunity to comment on the discussion in writing and/or orally at the forums which were held. Although not subject to the PURPA standards, CRSP is complying with those standards to the extent that it can reasonably do so as discussed in the referenced brochure.

Other Considerations

Public Comment Procedures

A number of comments reflected concern that the pro-

cedures followed by Western in promulgating the proposed rate increase did not conform to basic due-process-of-law requirements. The lack of opportunity for cross examination of witnesses and the absence of other formalities of evidentiary hearings were among the alleged deficiencies cited.

We are satisfied that the opportunities provided by Western for public information and comment were more than adequate. The reasons for the rate increase and the methodology used in developing it were fully explained. Requested information was supplied. The parties were afforded access to Western's computer program. All questions were answered. Because of the two occasions upon which changes were made, the comment period lasted more than 11 months. Formal evidentiary procedures are not required in the development and review of Federal power rates.

National Environmental Policy Act (NEPA)

A number of comments raised the issue of whether the rate adjustment is subject to provisions of the NEPA. Procedures for compliance with NEPA are applicable to CRSP ratemaking. A preliminary environmental evaluation was made for and reported in the April 1979 proposed power rate adjustment brochure. Subsequently, an environmental assessment has been made in accordance with NEPA. The environmental assessment indicates there are no significant environmental impacts expected as a result of the proposed rate adjustment.

Leavitt Act

Commenters also questioned whether the Leavitt Act, which is cited in Section 4 of P.L. 84-485, authorized reduced rates for Indians. Section 4 of P.L. 84-485 provides, in relevant part, that: "(d) as to Indian lands within, under or served by any participating project, payment of construction costs within the capability of the land to repay shall be subject to the Act of July 1, 1932 [Leavitt Act] (47 Stat. 564)."

The first provision of the Leavitt Act authorizes and directs the Secretary of the Interior "... to adjust or eliminate reimbursable charges of the Government of the United States existing as debts against individual Indians or tribes of Indians in such a way as shall be equitable and just in consideration of all the circumstances under which such charges were made...." (Act of July 1, 1932, 47 Stat. 564, 25 U.S.C. 386a). This portion of the Leavitt Act authorized the Secretary of the Interior to grant relief on a project-by-project basis from then existing obligations under the Indian Appropriations Act for Fiscal Year 1915 (Act of August 1, 1914, 38 Stat. 582, 583) to reimburse the Government for expenditures made for Indian irrigation projects. First, neither it nor the first proviso, which defers construction costs assessed "...against Indian-owned lands within any Government irrigation project....", applied to Reclamation projects. Solicitor Finney Opinion, 54 I.D. 90 (1932). Second, both portions of the act, which derived from separate bills, provide relief only from irrigation

costs and do not apply to power costs. Section 4 of P.L. 84-485 specifically makes the Leavitt Act applicable to participating projects, which are Reclamation projects. However, P.L. 84-485 does not extend the relief provided by the Leavitt Act. Consequently, since the Leavitt Act provides relief only from irrigation costs and not from power costs, neither Section 4 of P.L. 84-485 nor the Leavitt Act authorize reduced power rates for Indians.

Price Stability

There was a question whether any rate increases which Western might promulgate would be limited by the Council on Wage and Price Stability. On March 19, 1979, the Director of the Council on Wage and Price Stability stated in the preamble to the Interim Final Price Standard that "...while the price standard is intended to apply to all 'Government enterprises,' any statute mandating a particular pricing policy will, of course, take precedence." 44 FR 17910, 17911 (March 23, 1979). This interpretation of the price standards was verified in a letter to the Secretary of Energy from R. Robert Russell, the Acting Director for the Council on Wage and Price Stability. In that letter, dated August 28, 1979, the Council confirmed the Department of Energy's belief that "statutory requirements take precedence over the voluntary price standard" where power marketing administrations are involved.

Some concern remained within the Department of Energy over whether the price standard applied to the portion of the CRSP rate increase attributable to assistance for future participating CRSP projects which had not yet been funded. Differing opinions were offered on the matter as administrative interaction took place. In reaching the decision that the price standards were not applicable to any portion of the CRSP rate, the Western Area Power Administration concluded that there is no discretion to set a rate lower than that which would accumulate revenues for irrigation assistance in accordance with the apportionment formula of 43 U.S.C. 620d(e). The CRSP Act gives the Secretary discretion in the carrying out of the will of the Congress, but not to the point where repayment obligations become impaired. Revenues sufficient to assist future participating projects must be accumulated in the same manner as the Secretary of the Interior has done since the passage of the legislation in 1956. This approach is consistent with the CRSP Act, the legislative history, long-standing administrative interpretation and the ratification of that interpretation through the informed actions of Congress since 1956.

Availability of Information

Information regarding this rate adjustment, including studies, comments, transcripts, and other supporting material, is available for public review in the Salt Lake City Area Office, Western Area Power Administration, 438 East 200 South, Suite 2, Salt Lake City, Utah 84147; in the office of the Administrator, Western Area Power

Administration, 1536 Cole Boulevard, Golden, Colorado 80401; and in the office of the Director of Power Marketing Coordination, 12th and Pennsylvania Avenue, NW, Washington, D.C. 20461.

Submission to the FERC

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

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, effective January 23, 1981, Rate Schedules SP-F1 and SP-FP1. These rates shall remain in effect on an interim basis for a period of 12 months unless such period is extended or until the FERC confirms and approves these or substitute rates on a final basis, whichever occurs first.

Issued in Washington, DC, December 23, 1980.

Ruth M. Davis
Assistant Secretary
Resource Applications

Rate Schedule SP-F1
(Supersedes Schedule UC-F2)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

Colorado River Storage Project
**SCHEDULE OF RATES FOR WHOLESALE FIRM
POWER SERVICE**

Effective:

The first day of the first full billing period beginning on or after January 23, 1981.

Available:

In the area served by the Colorado River Storage Project.

Applicable:

To wholesale power customers for general power service supplied through one meter at one point of delivery.

Character and Conditions of Service:

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

Monthly Rate:

Capacity Charge:

\$1.655/kW of billing demand.

Energy Charge:

4.0 mills/kWh for all energy use up to, but not in excess of, the energy obligation under the power sales contract.

Billing Demand:

The billing demand will be the greater of (1) the highest 30-minute integrated demand established during the month up to, but not in excess of, the delivery obligation under the power sales contract, or (2) the contract rate of delivery.

Billing for Unauthorized Overruns:

For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual firm power and/or energy obligations, such overrun shall be billed at ten (10) times the above rate.

Adjustments:

For transformer losses:

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

For power factor:

None. The customer will normally be required to maintain a power factor at the point of delivery of between 95-percent lagging and 95-percent leading.

Rate Schedule SP-FP1
(Supersedes Schedule UC-FP2)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

Colorado River Storage Project
**SCHEDULE OF RATES FOR WHOLESALE
PEAKING POWER SERVICE**

Effective:

The first full day of the first full billing period beginning on or after January 23, 1981.

Available:

Within and adjacent to the marketing area of the Colorado River Storage Project.

Applicable:

To wholesale power customers purchasing such service under long-term contracts. Because of the nature of this class of service, it is applicable only to customers with other resources enabling them to utilize it.

Character and Conditions of Service:

As specifically established by contract. Delivery will be made from the transmission system of the United States at transmission voltage, and normally only during peak hours of the purchaser's load. Return of all energy furnished shall normally be required.

Monthly Rate:

Capacity Charge:

\$1.655/kW of the effective contract rate of delivery for peaking power or the maximum amount scheduled, whichever is the greater.

Energy Charge:

4.0 mills/kWh for all energy scheduled for delivery without return.

Billing for Unauthorized Overruns:

For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual obligation for peaking capacity and/or energy, such overrun shall be billed at ten (10) times the above rate.

Adjustments:

For power factor:

None. The customer will normally be required to maintain a power factor at the point of delivery of between 95-percent lagging and 95-percent leading.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR CONSERVATION
AND RENEWABLE ENERGY

In the Matter of:

Southwestern Power Administration—) Rate Order
System Rates) No. SWPA-8

ORDER EXTENDING CONFIRMATION AND
APPROVAL OF POWER RATES ON AN INTERIM
BASIS

(March 27, 1981)

Pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act, Public Law 95-91, the functions of the Secretary of the Interior and the Federal Power Commission under Section 5 of the Flood Control Act of 1944, 16 U.S.C. 825s, relating to the Southwestern Power Administration (Southwestern) were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 FR 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve, and place in effect such rates on an interim basis, and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary for Resource Applications under the delegation. By Delegation Order No. 0204-33, as amended, effective March 19, 1981, the Secretary of Energy vested in the Assistant Secretary for Conservation and Renewable Energy the authority previously vested in the Assistant Secretary for Resource Applications to develop power

and transmission rates, acting by and through the Administrator, and to confirm, approve and place in effect such rates on an interim basis, and delegated to the FERC the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary for Conservation and Renewable Energy. This rate order is issued pursuant to the delegation to the Assistant Secretary for Conservation and Renewable Energy.

BACKGROUND

Under the authority of Delegation Order No. 0204-33, effective January 1, 1979, 43 FR 60636 (December 28, 1978), the Assistant Secretary for Resource Applications, through Rate Order No. SWPA-1 issued March 1, 1979, placed into effect on April 1, 1979, increased System Rates on an interim basis for Southwestern. The rates, along with the rate order, basic studies, comments, transcripts, and other material concerning Southwestern's System Rate adjustment, were submitted to the FERC for confirmation and approval on a final basis pursuant to the authority vested in the FERC by Delegation Order No. 0204-33. These rates, which were the subject of Rate Order No. SWPA-1, superseded the following SWPA rates:

Rate Schedule F-1, Firm Power

Rate Schedule P-2 (Revised), Peaking Power

Rate Schedule EE, Excess Energy

Rate Schedule IC, Interruptible Capacity

Contract Rate in Section 2, Contract No. 14-02-001-864, Tex-La Electric Cooperative, Inc. (through TP&L)

The public was invited to review and comment on the development of new System Rates through Federal Register notices published during 1978. The public participation process produced numerous and varied questions and comments, all of which were considered and many of which were accepted and incorporated in developing the revised rates that were confirmed, approved and placed in effect on an interim basis by Rate Order No. SWPA-1.

The text of Rate Order No. SWPA-1 provided responses to the major comments criticisms and alternatives offered during the comment period. The order confirmed, approved, and placed in effect on an interim basis new System Rate Schedules which increased average annual revenues to accomplish repayment. The Assistant Secretary for Resource Applications confirmed and approved on an interim basis the following five rate schedules and one contract rate for Southwestern, to become effective April 1, 1979, and replace the four rate schedules and the first contract rate listed previously:

Rate Schedule P-3, Peaking Power

Rate Schedule F-2, Firm Power from Integrated System

Rate Schedule F-3, Firm Power through Oklahoma Utility Companies

Rate Schedule EE-2, Excess Energy

Rate Schedule IC-2, Interruptible Capacity

Contract No. 14-02-001-864, Section 2, Tex-La Electric Cooperative, Inc. (through TP&L)

These rates were to remain in effect on an interim basis for a period of 12 months unless such period were extended or until the FERC confirmed and approved these or substitute rates on a final basis. Due to the lack of action by the FERC, these rates were extended on an interim basis by Rate Order No. SWPA-4 through March 31, 1981, by the Assistant Secretary for Resource Applications.

DISCUSSION

Due to the extraordinary number of Federal power rate orders submitted to the FERC, a ruling has not been handed down on the System Rates of Southwestern. It is necessary, therefore, for the Assistant Secretary for Conservation and Renewable Energy to extend interim approval of Southwestern's Integrated System Rate Schedules and the Tex-La Electric Cooperative, Inc., Contract Rate for an additional 1-year period.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby extend confirmation and approval on an interim basis, effective April 1, 1981, of Rate Schedules P-3, F-2, F-3, EE-2, IC-2, and the Contract Rate under Section 2 of the Tex-La Electric Cooperative, Inc., Contract No. 14-02-001-864. These rates shall remain in effect on an interim basis for a period of 12 months unless such period is again extended or until the FERC confirms and approves these or substitute rates on a final basis.

Issued at Washington, DC, this 27th day of March 1981.

Frank DeGeorge
Acting Assistant Secretary
Conservation and Renewable
Energy

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR CONSERVATION
AND RENEWABLE ENERGY

In the Matter of:

Western Area Power Administration—) Rate Order
Parker-Davis Project Power Rates) No. WAPA-6

ORDER CONFIRMING AND APPROVING AN EXTENSION OF POWER AND TRANSMISSION RATES ON AN INTERIM BASIS (May 14, 1981)

Pursuant to section 302(a) of the Department of Energy Organization Act, 42 U.S.C. 7152(a), the power marketing functions of the Secretary of the Interior under the Reclamation Act of 1902, 43 U.S.C. 372, *et seq.*, as amended and supplemented by subsequent enactments, particularly by section 9(c) of the Reclamation Project Act of 1939, 43 U.S.C. 485h(c), and acts specifically applicable to the Parker-Davis Project, for the Water and Power Resources Service (formerly the Bureau of Reclamation) were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 FR 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve, and place in effect such rates on an interim basis, and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. Due to a Department of Energy organizational realignment, delegation Order No. 0244-33 was amended, effective March 19, 1981, to transfer the authority of the Assistant Secretary for Resource Applications to the Assistant Secretary for Conservation and Renewable Energy. This rate order is issued pursuant to the delegation to the Assistant Secretary for Conservation and Renewable Energy.

BACKGROUND

Pursuant to Delegation Order No. 0204-33, on May 15, 1980, the Assistant Secretary for Resource Applications issued Rate Order No. WAPA-3 (45 FR 34046, May 21, 1980) confirming and approving on an interim basis, effective the first day of the first full billing period beginning on or after June 16, 1980, Rate Schedules PD-F1, PD-T1, PD-T2, and PD-T3 for wholesale power and transmission service marketed by the Western Area Power Administration's (Western) Parker-Davis Project. The rate order stated that the rates "...shall remain in effect on an interim basis for a period of 12 months unless such period is extended, or until the FERC confirms and approves these or substitute rates, on a final basis, whichever occurs first." The rate schedules were submitted to the FERC for confirmation and approval on a final basis by the Assistant Secretary for Resource Applications' letter on May 15, 1980.

DISCUSSION

In as much as the FERC is not expected to complete its confirmation and approval of the Parker-Davis Project power and transmission rates by June 30, 1981, a further extension of the interim rates is necessary.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, effective the first day of the first full billing period beginning on or after June 16, 1981, an extension of existing Rate Schedules PD-F1, PD-T1, PD-T2, and PD-T3. These rates shall remain in effect through June 30, 1982, unless extended, or until the FERC confirms and approves them, or substitute rates, on a final basis.

Issued in Washington, D.C., May 14, 1981.

Frank DeGeorge
Acting Assistant Secretary
Conservation and Renewable Energy

Rate Schedule PD-F1
(Supersedes Rate Schedule LC-F2)

UNITED STATES DEPARTMENT OF ENERGY WESTERN AREA POWER ADMINISTRATION

Parker-Davis Project, Arizona-California-Nevada SCHEDULE OF RATES FOR WHOLESALE FIRM POWER SERVICE

Effective:

The first day of the first full billing period beginning on or after June 16, 1980.

Available:

In the area served by the Parker-Davis Project.

Applicable:

To wholesale power customers for general electric service supplied through one meter at one point of delivery.

Character and Conditions of Service:

Three-phase alternating current at sixty (60) Hertz, delivered and metered at the voltages and points of delivery specified in the service contract.

Monthly Rate:

Capacity Charge:

\$1.82 per kilowatt of billing demand.

Energy Charge:

4.15 mills per kilowatthour for each kilowatthour scheduled and/or delivered, not to exceed the delivery obligation under the electric service contract.

Billing Demand:

The billing demand will be the greater of (1) the highest 30-minute integrated demand established during the month up to, but not in excess of, the delivery obligation under the power sales contract, or (2) the contract rate of delivery.

Billing for Unauthorized Overruns:

For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual firm power and/or energy obligations, such overrun shall be billed at ten (10) times the above rates.

Adjustments:

For Transformer Losses:

If delivery is made at transmission voltage but metered on the low-voltage side of the transformer, the meter readings will be increased two (2) percent to compensate for transformer losses.

For Power Factor:

None. The customer will normally be required to maintain a power factor at the point of delivery of between 95 percent lagging and 95 percent leading.

Rate Schedule PD-T1

UNITED STATES DEPARTMENT OF ENERGY WESTERN AREA POWER ADMINISTRATION

Parker-Davis Project, Arizona-California-Nevada SCHEDULE OF RATES FOR FIRM TRANSMISSION SERVICE

Effective:

The first day of the first full billing period beginning on or after June 16, 1980.

Available:

In the area served by the Parker-Davis Project.

Applicable:

To firm transmission service customers where power and energy are supplied to the Parker-Davis system at points of interconnection with other systems and transmitted and delivered, less losses, to points of delivery on the Parker-Davis system specified in the service contract.

Character and Conditions of Service:

Transmission service for three-phase alternating current at sixty (60) Hertz, delivered and metered at the voltages and points of delivery specified in the service contract.

Rate:

Transmission Service Charge: \$6.80 per kilowatt per year for each kilowatt contracted for at the point of

delivery as specified in the service contract, payable monthly at the rate of \$0.567 per kilowatt.

Adjustments:

For Reactive Power:

None. There shall be no entitlement to transfer of reactive kilovolt-amperes at delivery points, except when such transfers may be mutually agreed upon by Contractor and Contracting Officer or their authorized representatives.

For Losses:

Power and energy losses incurred in connection with the transmission and delivery of power and energy under this rate schedule shall be supplied by the customer in accordance with the service contract.

Rate Schedule PD-T2

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
Parker-Davis Project, Arizona-California-Nevada

**SCHEDULE OF RATES FOR TRANSMISSION
SERVICE OF COLORADO RIVER STORAGE
PROJECT (CRSP) POWER AND ENERGY**

Effective:

The first day of the first full billing period beginning on or after June 16, 1980.

Available:

In the area served by the Parker-Davis Project.

Applicable:

To Colorado River Storage Project (CRSP) Southern Division customers where such power and energy are supplied to the Parker-Davis system by CRSP at points of interconnection with the CRSP system and for transmission and delivery, less losses, to Southern Division customers at points of delivery on the Parker-Davis system specified in the service contract.

Character and Conditions of Service:

Transmission capacity for three-phase alternating current at sixty (60) Hertz, delivered and metered at the voltages and points of delivery specified in the service contract.

Rate:

Transmission Service Charge: \$3.67 per kilowatt of the maximum allowable rate of delivery made available at each point of delivery during each season as specified in the service contract; payable monthly at the rate of \$0.612 per kilowatt.

Adjustments:

For Reactive Power:

None. There shall be no entitlement to transfer of reactive kilovolt-amperes at delivery points, except when such transfers may be mutually agreed upon by Contractor and Contracting Officer or their authorized representatives.

For Losses:

Power and energy losses incurred in connection with the transmission and delivery of power and energy under this rate schedule shall be supplied by the customer in accordance with the service contract.

Rate Schedule PD-T3

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
Parker-Davis Project, Arizona-California-Nevada

**SCHEDULE OF RATES FOR NONFIRM
TRANSMISSION SERVICE**

Effective:

The first day of the first full billing period beginning on or after June 16, 1980.

Available:

In the area served by the Parker-Davis Project.

Applicable:

To nonfirm transmission service customers where power and energy are supplied to the Parker-Davis system at points of interconnection with other systems and transmitted and delivered subject to the availability of transmission capacity, less losses, to points of delivery on the Parker-Davis system specified in the service contract.

Character and Conditions of Service:

Transmission service on an intermittent basis for three-phase alternating current at sixty (60) Hertz, delivered and metered at the voltages and points of delivery specified in the service contract.

Rate:

Transmission Service Charge: 1.3 mills per kilowatt-hour for each kilowatthour scheduled, payable monthly.

Adjustments:

For Reactive Power:

None. There shall be no entitlement to transfer of reactive kilovoltamperes at delivery points, except when such transfers may be mutually agreed upon by Contractor and Contracting Officer or their authorized representatives.

For Losses:

Power and energy losses incurred in connection with the transmission and delivery of power and energy under

this rate schedule shall be supplied by the customer in accordance with the service contract.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR CONSERVATION
AND RENEWABLE ENERGY

In the Matter of:

Western Area Power Administration—)
Central Valley Project Rates for) Rate Order
Centralia and Other Northwest) No. WAPA-8
Sales to Pacific Gas and Electric
Company

ORDER CONFIRMING AND APPROVING
REVISED RATE METHODOLOGY
(June 19, 1981)

Pursuant to section 302(a) of the Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*, the power marketing functions of the Secretary of the Interior under the Reclamation Act of 1902, 43 U.S.C. 372, *et seq.*, as amended and supplemented by subsequent enactments, particularly by section 9(c) of the Reclamation Project Act of 1939, 43 U.S.C. 485h(c), for the Bureau of Reclamation were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 FR 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve, and place in effect such rates on an interim basis, and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. Due to a Department of Energy organizational realignment, Delegation Order No. 0244-33 was amended, effective March 19, 1981, to transfer the authority of the Assistant Secretary for Resource Applications to the Assistant Secretary for Conservation and Renewable Energy. This rate order is issued pursuant to the delegation to the Assistant Secretary for Conservation and Renewable Energy.

BACKGROUND

Public Notice and Comment

In accordance with the rate adjustment procedures in 45 FR 86976 (December 31, 1980), on February 27, 1981, the Western Area Power Administration (Western) announced a proposed power rate adjustment for sales to the Pacific Gas and Electric Company (PG and E) for Centralia and other Northwest power (46 FR 14434). Interested persons were invited to participate in public

forums and to submit written comments relative to the rate adjustment. A public information forum was held in Sacramento, California, on March 17, 1981. A presentation of the proposed rates, basis for the rates, and the method to be used in computing Centralia "pass-through" rates was made along with a discussion of sales for other Northwest energy. An overview of Centralia history was discussed. A question and answer session followed, after which the meeting was concluded. A public comment forum was held in Sacramento, California, on March 31, 1981. No oral comments were made. Two written comments were received by April 16, 1981, the end of the comment period.

History of Existing Rates (Split Rate)

The power resources of the Central Valley Project (CVP) consist of 10 hydroelectric plants totaling 1,709 megawatts which are currently supplemented by the import of 400 megawatts of capacity and associated energy from this Northwest. Most of the power imported from the Northwest is obtained at the Centralia Powerplant located 85 miles south of Seattle, Washington.

Under Contract No. 14-06-200-2948A with PG and E (the PG and E contract), the output from CVP hydroelectric powerplants, plus the 400 megawatts of capacity and associated energy imported from the Northwest, are first used within the northern California area to serve CVP preference customer loads. The contract also provides for the sale of capacity and energy in excess of the quantities currently needed to meet the CVP's obligations to serve preference customer loads to PG and E for credit in a banking arrangement. These amounts can be repurchased as needed in future years to meet the CVP's load requirements.

Initially the PG and E contract provided for the sale of Northwest power at a rate consisting of a capacity charge of 75 cents per kilowatt per month and energy block charges of 4, 3, and 2 mills per kWh. This was the same rate that was then being charged CVP customers for power and energy from the CVP facilities.

Northwest imports began in 1968 with the purchase of power from the Bonneville Power Administration. Regular imports from the Centralia Powerplant began in 1972, and were delivered pursuant to the terms in the PG and E contract.

Article 32 of the PG and E contract provides in part that:

"Rates and charges under this contract shall be fair and equitable and shall...be jointly reviewed and adjusted as appropriate on April 1, 1971, and every 5 years thereafter.... Such review shall take into account substantial savings accruing to either party and applicable costs of construction and production, including changes therein and appropriate service charges, during the preceeding 5 years. If the parties are unable to agree on a change of any rate or charge, the matter shall be submitted to the Federal Power Commission for final decision."

The first opportunity to review and adjust the Centralia rate was April 1, 1971. However, the rate was not adjusted at that time because the Centralia plant was not then in operation and the costs of Centralia capacity and energy were not known. When the first unit of the Centralia plant was placed in service in the fall of 1971, its costs were greater than those which were originally estimated. Principally because of the higher cost of Centralia power, the CVP began falling behind in its repayment obligation under Federal law.

In conjunction with the review of the proposed general rate increase for the CVP in 1974 and 1975, the possibility of adjusting the Centralia rates at the next opportunity, April 1, 1976, for that portion of the capacity and energy sold to PG and E was also considered. This resulted in the existing method for setting Centralia rates which is embodied in a December 14, 1976, Department of the Interior final position document entitled "Final Position on and [sic] Adjustment in Rates to the Pacific Gas and Electric Company for Northwest Capacity and Energy," also known as the Frizzell decision. Under the Frizzell decision, PG and E is charged the flow-through or actual cost for energy received from the Northwest, and the flowthrough capacity charge for that portion of the capacity associated with energy at a 60-percent capacity factor. The balance of the Northwest capacity delivered to PG and E is charged at the CVP rate for firm capacity. This resulted in a "split rate" for capacity charges to PGandE.

The costs of transmission service for the Pacific Northwest-Pacific Southwest Intertie from Malin, Oregon, to Tracy, California, were excluded as an element to be recovered by the rate formula established by the Frizzell decision.

1981 Rate Adjustment (Passthrough Rate)

Again in 1978 and 1979 the possibility of adjusting the Centralia rates was considered in conjunction with the proposed general rate increase for the CVP. The Assistant Secretary for Resource Applications' rate order of October 2, 1979, WAPA-2 (44 FR 57962 dated October 9, 1979), which approved increased rates on the CVP on an interim basis, discussed the flowthrough of costs to PGandE. The position taken in the rate order was that the split rate would not be perpetuated beyond April 1, 1981, which, as provided in the PGandE contract, was the next opportunity to adjust the rates for Centralia power.

By letter agreement on January 27, 1981, between Western and PGandE, the date for review was extended to July 1, 1981. However, pursuant to that letter agreement, rates for Centralia capacity and energy would be retroactively effective from April 1, 1981, to December 31, 1981, the end of the Centralia contract.

The method for determining rates for the next 5 years beginning April 1, 1981, for other energy which may become available from the Northwest for sale to PGandE is also a part of this rate order. Except for the addition

of a ceiling, the rate for other Northwest energy is the same as the rate under the Frizzell decision.

DISCUSSION

Basis for Changing from Split Rate to the Passthrough Rate

The passthrough rate will recover all costs incurred by CVP in the purchase and sale of Centralia power to PGand E, including reserves and the intertie wheeling charge from Malin, Oregon, to Tracy, California. In computing costs to PGandE, the rate will apply to the portion of Centralia capacity and energy that is not used to supply preference customer loads. However, Western is not attempting to recover from PGandE past losses in the sale of Centralia power to PGandE.

The passthrough rate is consistent with the discussion on "Flow Through" of Costs to PGandE" in the rate order WAPA-2 dated October 2, 1979, (44 FR 57462 dated October 9, 1979).

The rate more nearly reflects the cost to the CVP and is considered to be fair and equitable. Western estimates that, based upon a declared project dependable capacity (PDC) of 813 megawatts, the Centralia passthrough rate will increase CVP revenues by \$2,884,000 over the current "split rate" method. However, if the PDC level remains at 554 megawatts, which is PGandE's position, the rate will not change the revenues to the CVP.

The estimated Centralia project rate to PGandE is \$5.07 per kilowatt (kW) per month for capacity, and 16.758 mills per kilowatthour (kWh) for energy.

CVP preference customers have in the past supported the concept of a full cost passthrough rate to PGandE for sales from Centralia and other Northwest energy that cannot be used by the customers. PGandE feels that the passthrough rate is an unwarranted change from the split rate policy established in 1976 (decision document dated December 14, 1976) by the Department of the Interior.

CVP preference customers rightfully claim that under the current criteria they must repay any cost not recovered in sales to PGandE. Customers estimate that through April 1, 1981, \$70 million was lost on sales to PGandE and that this loss will have to be recovered from CVP preference users. Western agrees with these points. The customers state that at one time it was suggested that the loss could be recovered through lower bank account rates, but that the rates for withdrawal from the bank accounts are now estimated to be above the costs of alternative power resources. Thus, it is possible there will be no savings to the customers.

PGandE contends that the split rate recovers Western's costs and that Western does not give any reason to depart from the split rate method. PGandE maintains that conditions have not changed since 1976 and that they get whatever Centralia power is left over.

PGandE agreed to the provisions in the PGandE contract regarding disposition of Centralia power to PGandE and this provision is only one part of the costs and benefits of the whole contract. The reason Western proposes the full passthrough rate to PGandE is to recover all of the costs associated with delivering the power to PGandE. The split rate does not recover all costs and thus requires CVP customers to repay those costs not recovered from PGandE. In addition, article 32 of the PGandE contract requires consideration of substantial savings accruing to either party during the preceding 5 years. Previous sales to PGandE have without question resulted in substantial savings to the company. Therefore, we believe it is entirely equitable and contractually valid within the intent of article 32 for the rates on Centralia sales to PGandE to be based on the passthrough of all costs.

PGandE claims that its customers would pay for Centralia capacity without sufficient energy to justify the rate. They state that PGandE consumers are required to pay for nearly all of the Centralia capacity even though they receive little or no energy. PGandE cites a Department of the Interior memorandum dated September 1, 1976, which supports the split rate decision because the alternative-costs concept requires that the rates set for PGandE accurately reflect the value to PGandE of Northwest energy and capacity it receives. The Department of the Interior 1976 decision document also showed that PGandE is expected to receive Northwest power at an annual load factor decreasing from about 35 percent in 1976 to 12 percent during 1980.

The PGandE contract covering the period from July 31, 1967, through 2004 is a complex contract designed to benefit both parties. It provides that power made available from the Northwest is delivered to CVP preference customers first with the remainder delivered to PGandE and PGandE agrees to accept and pay for the surplus Northwest energy and firm capacity. PGandE fails to give an overview of the benefits received by PGandE under the entire contract for the delivery of Centralia power. Nor does PGandE demonstrate that the value of service which Western provides is less than the cost of alternative sources available to PGandE.

The level of project dependable capacity for the CVP is currently an item of dispute between PGandE and Western. PGandE fails to mention that under their position on the determination of the level of PDC they would be receiving firm energy without paying a capacity charge. Under Western's position, PGandE would pay for 145 megawatts of the 382 megawatts imported from Centralia. Under either level of PDC, the cost of the full pass-through rate will be much less than the alternative cost available to PGandE of either purchasing power or constructing new facilities.

PGandE's arguments concerning the relatively low capacity factor for the Centralia power sold to PGandE are irrelevant, since firm capacity with variable amounts of energy is what PGandE contracted to take and pay for. The capacity factor which results from such sales has no

bearing on Western's cost of providing service. Under the passthrough rates, Western will simply recover its costs of capacity and energy, irrespective of capacity factor. However, even assuming a less-than-average water year, PGandE would still receive Centralia power at approximately a 45-percent capacity factor from April 1, 1981, through December 31, 1981, instead of the 12 percent quoted in the 1976 memorandum. Thus, PGandE's argument that PGandE receives little or no energy with the firm capacity is not correct.

Burden on PGandE's Customers

PGandE contends that the passthrough of the full cost of Centralia capacity sold to PGandE would result in an inequitably high price for its consumers. PGandE states that while Western estimates its unit cost of Centralia power (capacity and energy) to be 25 mills per kWh, Western proposes to sell Centralia power to PGandE at a unit price of about 41 mills per kWh while the unit price to CVP preference customers would be about 10 mills per kWh. PGandE believes this places an unfair burden on its customers and results in an unauthorized subsidy to CVP preference customers.

PGandE derived the unit price of Centralia power to PGandE by using a much lower capacity factor than they will actually receive from April 1 through December 31, 1981. Based on a realistic capacity factor of approximately 45 percent for that time period, the unit price of Centralia power to PGandE is about 33 mills per kWh under Western's proposed PDC level. Under PGandE's proposed PDC level, the Centralia rate to PGandE would be approximately 17 mills per kWh. Since the incremental cost for energy alone for PGandE is more than twice the 33 mills per kWh rate, Western does not feel that the Centralia rate results in an inequitable price to PGandE.

The average CVP rate to its preference customers, which includes power from both CVP hydro facilities and Centralia, is approximately 10 mills per kWh. If Centralia power was sold separately to CVP preference customers, the rate for such power would be much higher than the 10 mills per kWh quoted.

As pointed out earlier, Western, under the passthrough rate for capacity and energy separately, irrespective of capacity factor, will simply recover its costs of purchasing the capacity and energy. Western also does not believe that selling Centralia power to PGandE at the same cost incurred by Western in purchasing it involves a subsidy to the CVP preference customers. Recovering cost is a basic guideline in setting rates. PGandE relies on this principle in its own rate filings.

Recovery of Pacific Northwest-Pacific Southwest Inter-tie Cost in Centralia Rate

PGandE notes that the split rate arrangement for Centralia power did not include a portion of transmission cost for the Pacific Northwest-Pacific Southwest Intertie (Intertie) and questions the rationale for Western including transmission costs in its current proposal. They

state that there is no provision in the PGandE contracts for PGandE payment of any transmission charge associated with non-CVP power.

The split rate decision was an administrative decision based on other considerations in addition to costs incurred in the delivery of Centralia power. Western's proposal is to use a cost-based rate, the same principle that utilities use in setting rates. The Centralia power cannot be delivered without transmission costs.

It is true that the PGandE contract does not specifically provide for transmission costs to be charged in the rate. However, the contract does not specify any costs to be included in or excluded from the rate. The only limitation in the contract is that the rates should be "fair and equitable." Western believes that since transmission costs are incurred in rendering the service to PGandE, then those costs should appropriately be reflected in the rate.

Intertie Costs After Expiration of Centralia Contract

One customer disagreed with Western's proposal of not charging PGandE for use of the intertie for sales of surplus energy to PGandE after December 31, 1981. They cite that intertie costs are correctly included in the computation of Centralia rates and that a procedure should be developed to assign intertie costs between the preference customers and PGandE based upon surplus sales transmitted over the intertie.

Under Western's proposal for Centralia rates, the cost of the intertie is already included and thus there is no basis for an extra charge for surplus energy during that time period. After December 31, 1981, the Centralia contract for firm energy expires and only surplus energy will be transmitted. Western does not believe that the \$3.35 per kW per year firm capacity charge should be included in nonfirm energy costs as this would require marketing capacity based on an equivalent energy charge. Western does not anticipate significant sales of nonfirm Northwest energy to PGandE under this rate. Further, Western is seeking a source of firm capacity and energy to input into the area utilizing the intertie, and is currently proposing to market surplus transmission capacity available in Western's share of the intertie. Separate rates would be negotiated for such power and transmission capacity.

Rate for Other Northwest Energy

One customer and PGandE recommended that the method of cost calculation be more clearly defined with regard to capacity as well as energy. PGandE further commended [sic] that Western's rate to PGandE is open-ended in that there is no ceiling on the cost of the energy and that there is no provision in the rate that the energy imported into the area must be capable of being beneficially used by PGandE.

Because Western currently does not have any specific sources for importation of energy from the Northwest, the cost associated with the purchase of any surplus energy from that area cannot be quantitatively described. Western also agrees to place a ceiling on the cost of

Northwest energy sold to PGandE and proposes that the ceiling be based on PGandE's rate (based on alternative costs) from small power producers and cogenerators under the requirements of the Public Utility Regulatory Policies Act of 1978. This does not affect the rate methodology approved by this rate order, but rather places a variable ceiling on the rate. Interested parties may review the costs that are incurred by Western in purchasing energy from the Northwest.

Western agrees with PGandE's proposal that energy should be imported into the area only when it can be beneficially used. This issue is covered by the PGandE contract; and to the extent the PGandE contract does not cover the issue, Western believes that it should be a matter of contract negotiation between the parties and not made a part of a rate order.

Environmental Impact

Western has reviewed the possible environmental impacts of the power rate adjustment and has concluded that, because the increased rates would not significantly affect the quality of the human environment within the meaning of the National Environmental Policy Act of 1969, the action is not a major Federal action for which an environmental impact statement is required.

Availability of Information

Information regarding this rate adjustment is available for public review in the Sacramento Area Office, Western Area Power Administration, 2800 Cottage Way, Sacramento, California 95825, Office of the Administrator, Western Area Power Administration, 1536 Cole Boulevard, Golden, Colorado 80401, and in the Office of the Director of Power Marketing Coordination, 12th and Pennsylvania Avenue, NW., Washington, DC 20461.

Rates Not Being Placed in Effect On An Interim Basis

In view of PGandE's disagreement on the proposed rates and consistent with article 32 of the PGandE contract cited above, the rates are not being placed in effect on an interim basis, but are being submitted to FERC for final determination.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby approve Western's passthrough rate methodology for determining the rates for sales of Centralia capacity and energy and Northwest energy to the Pacific Gas and Electric Company. These rates will be effective April 1, 1981, through December 31, 1981, for Centralia power sales and April 1, 1981, through March 31, 1986, for other Northwest energy sales if this order is approved by the FERC.

Issued in Washington, DC, June 19, 1981.

Joseph J. Tribble
Assistant Secretary
Conservation and Renewable Energy

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

Central Valley Project, California

**SCHEDULE OF RATES FOR CENTRALIA AND
NORTHWEST SALES TO THE PACIFIC GAS
AND ELECTRIC COMPANY**

Effective:

The rates for Centralia power will be effective from April 1, 1981, through December 31, 1981, and the rate for Northwest power will be effective from April 1, 1981, through March 31, 1986.

Available:

In the area served by the Central Valley Project (CVP).

Applicable:

To sales of capacity and/or energy to the Pacific Gas and Electric Company (PGandE) under the terms of Contract Number 14-06-200-2948A.

Character and Conditions of Service:

Power will be deemed to be delivered at the Tracy Switchyard at a nominal voltage of 230,000 volts.

Monthly Rate:

The rate for Centralia power will be determined as follows:

The *capacity rate* will be the annual cost of Centralia capacity and will be calculated as the sum of:

1. One hundred percent of the annual fixed cost to CVP of the Centralia facilities.
2. Sixty-five percent of the annual operation and maintenance cost to CVP of the Centralia facilities.
3. Ten percent of the annual fuel cost to CVP of the Centralia facilities.
4. That part of the annual cost of wheeling and capacity reserve paid to the Bonneville Power Administration by CVP proportional to the capacity component of the total capacity and energy cost of Centralia.
5. The annual cost to CVP for the use of the Pacific Northwest-Pacific Southwest Intertie facilities, which includes a \$3.35 charge per kilowatt/year plus an operation and maintenance cost.

The monthly capacity charge per kilowatt will be the total annual cost for Centralia capacity divided by 12, and then by 382,000 kilowatts, which is the Centralia capacity delivered to the CVP load center at Tracy.

The *energy rate* will be the annual cost of Centralia energy up to 7,050 kilowatt hours per kilowatt/year, and will be calculated as the sum of:

1. Thirty-five percent of the annual operation and maintenance cost to CVP of the Centralia facilities.
2. Ninety percent of the annual fuel cost to CVP of the

Centralia facilities.

3. That part of the annual cost of wheeling and capacity reserve paid to the Bonneville Power Administration by CVP proportional to the energy component of the total capacity and energy cost of Centralia.
4. Estimated annual energy support for Centralia purchased by CVP.

The energy costs per kilowatthour will be the total energy cost to CVP of the Centralia energy divided by the Centralia energy delivered to the CVP load center at Tracy during the year.

The rate for Northwest energy in excess of 7,050 kilowatt-hours per kilowatt per year from Centralia through December 31, 1981, and all Northwest energy after December 31, 1981, will be determined by cost as purchased from the Northwest and adjusted upward for losses to the CVP load center at Tracy, provided that the rate for Northwest energy will not exceed PGandE's energy rate(s) which PGandE would offer to small power producers and cogenerators under the Public Utility Regulatory Policies Act of 1978.

Adjustments:

The billing to PGandE for Centralia power purchased from April 1, 1981, through December 31, 1981, will be adjusted during January 1982, as necessary, based upon the best data available to the CVP, and as soon as possible thereafter will be readjusted as necessary based on the actual billed power costs to CVP.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR CONSERVATION
AND RENEWABLE ENERGY

In the Matter of:

Bonneville Power Administration —) Rate Order
Systemwide Wholesale Power Rates) No. BPA-4

ORDER CONFIRMING, APPROVING, AND
PLACING INCREASED POWER RATES INTO
EFFECT ON AN INTERIM BASIS
(June 24, 1981)

The functions of the Secretary of the Interior and the Federal Power Commission under the Bonneville Project Act, 16 U.S.C. 832, the Federal Columbia River Transmission System Act, 16 U.S.C. 838, and other statutes relating to the Bonneville Power Administration (BPA) were transferred to and vested in the Secretary of Energy pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act, Public Law 95-91. The Secretary of Energy, pursuant to section 7(i) (6) of the Pacific Northwest Electric Power Planning and Conservation Act (Public Law 96-501) is authorized to

approve BPA power and transmission rates on an interim basis during a 1-year period, pending establishment of procedures by the Federal Energy Regulatory Commission (FERC) for approving rates on an interim basis, in the event the FERC determines such procedures are necessary. Upon the advice from the FERC that such procedures are necessary and will not be established prior to October 1, 1981, the Secretary of Energy delegated to the Assistant Secretary for Conservation and Renewable Energy in the June 19, 1981 Supplement to Delegation Order No. 0204-33, the authority to confirm, approve, and place into effect such rates on an interim basis. This rate order is issued pursuant to that delegation to the Assistant Secretary.

BACKGROUND

Existing Rates

Wholesale power from the BPA system is delivered to 161 customers pursuant to rates in effect on an interim basis since December 20, 1979. The rates were approved on an interim basis by the Assistant Secretary for Resource Applications by Rate Order No. BPA-2 issued on December 3, 1979. On that same date the rates were submitted to the FERC for confirmation and approval on a final basis. Under Docket No. EF-80-2011 the FERC issued an order on November 21, 1980, remanding those rates without prejudice. BPA's response indicating the basis on which estimates of the revenues were made and otherwise answering the remand order will be separately submitted.

The eight rate schedules now in effect on an interim basis are:

EC-8, Wholesale Firm Power Rate; EC-9, Reserve Power Rate; IF-2, Wholesale Power Rate for Industrial Firm Power; MF-2, Wholesale Power Rate for Modified Firm Power; F-7, Wholesale Firm Capacity Rate; F-8, Emergency Capacity Rate; J-2, Wholesale Firm Energy Rate; and H-6, Wholesale Nonfirm Energy Rate.

Approval on an interim basis was also granted in Rate Order BPA-2 of BPA's General Rate Schedule Provisions and special contract rates and rate schedule provisions.

Need for Rate Increase

Pursuant to the Bonneville Project Act (Pub. L. L. 75-329 as amended), the Federal Columbia River Transmission System Act (Pub. L. 93-454), the Reclamation Project Act of 1939 (Pub. L. 85-611, as amended), the Flood Control Act of 1944 (Pub. L. 78-534), Section 2 of the Grand Coulee Third Powerhouse Authorization (Pub. L. 89-448 as amended) and the Pacific Northwest Electric Power Planning and Conservation Act (Pub. L. 96-501), the BPA Administrator conducted a revised power repayment study to determine the revenue necessary to recover the cost of producing, purchasing, and transmitting the electric power that BPA markets, to repay investments as required by statute, and to

recover other costs associated with the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act). The results of the study showed the need for a 78.5-percent increase in total revenues over the repayment study period, excluding revenues required to cover the costs of acquiring the investor-owned utility exchange resources. The total revenues needed will be met by the increase in wholesale power rates approved by this order and the increase in transmission rates approved by my Rate Order No. BPA-5.

The costs of the utility exchange resources have not yet been determined. BPA will acquire that power at the average system cost of the seller which will be determined using a methodology currently being developed. The variable "X" represents the dollar amount of the exchange in the appropriate studies and rate schedules.

The existing wholesale power and transmission rate schedules would produce revenues of approximately, \$630,000,000 in fiscal year 1982, assuming average water conditions. The new wholesale power and transmission rates would produce approximately \$1,100,000,000 during that year under these same conditions, excluding revenues associated with the exchange costs. BPA expects the cost of the exchange resources to fall between \$350 million and \$500 million. The cost of the exchange purchases has not been determined because the methodology for that determination requires a separate review process and separate approval by the FERC.

Present revenues are inadequate for a number of reasons. Since the last time rates were adjusted, there have been significant cost increases, including the addition of new programs required by the Regional Act. The cost increases include substantial increases in the construction cost of nuclear power plants from which BPA has acquired power generation capability, other purchase power costs, interest costs, and the costs to operate, maintain, and construct new Federal generation and transmission facilities. These cost increases have not been matched by revenue increases. In fact, revenues from the 1979 rate levels have been less than forecasted. New programs add substantial costs and include funding for the Regional Planning Council, fish and wildlife, local government assistance, load forecasting, increased public involvement, system planning, energy conservation, and new resources.

Public Notice and Comment

In response to the current power repayment study which showed that revenues from current rates were inadequate to meet BPA's repayment obligation, BPA published in the June 12, 1980, *Federal Register* (45 FR 34885) a "Notice of Intent to Develop Revised Wholesale Power Rates." Between June and December 1980, BPA met with various customer groups to elicit their comments and suggestions for an initial wholesale power rate proposal.

On December 5, 1980, the Regional Act became law. Sections 5, 7, and 9 of that Regional Act altered BPA's rate development procedures, costing methodology, and

in some cases, rate design. BPA published proposed wholesale power rates in the February 17, 1981 *Federal Register* (46 FR 12659) based on the requirements of the Regional Act. The initial rate proposals were supported by an environmental assessment, a power repayment study, a cost-of-service analysis, a long run incremental cost analysis, a time-differentiated pricing analysis, and a rate design study.

On March 2, 1981, the formal hearing process required by the Regional Act began with a BPA presentation of the initial rate proposals. The BPA staff was cross-examined and 37 parties presented their testimony. Rebuttal testimony was taken, and oral arguments and briefs were presented. The hearing closed for wholesale power rates on May 4, 1981, with over 6,000 pages of transcript. The BPA staff prepared an evaluation of the record that was made available to the parties on May 27, 1981, for their review. Written comments on the initial proposals were received through May 27, 1981. An addendum to the staff evaluation of the record covering meetings on transmission issues that were received too late to be included in the initial evaluation document was also prepared. The hearing officer certified the record and determined that it was unnecessary to supplement the evaluation of the record. On the basis of the record, the Administrator developed his final proposed rate schedules and General Rates Schedule Provisions. These schedules and provisions are given interim approval by this order.

In addition to studies conducted by BPA, the Administrator issued a Record of Decision documenting the process by which the rates were developed. This includes the significant public comments received, BPA's responses to such comments, and the rationale for the Administrator's decisions.

Studies Conducted by BPA

The new wholesale power rates are based on studies conducted by BPA. Studies were conducted two or more times to reflect the most recent cost data available and to make changes as a result of public comment. The studies conducted were: Power Repayment Study, April 1, 1980 (revised), February 24, 1981 (revised), April 23, 1981 (current and revised); May 14 1981 (current and revised); Cost-of-Service Analysis, February 1981, June 1981; Long Run Incremental Cost Analysis, February 1981, June 1981; Time-Differentiated Pricing Analysis, February 1981, June 1981; Wholesale Power Rate Design Study (formerly the Summary Rate Design Study), February 1981, June 1981; Staff Evaluation of Official Record, May 1981, and Addendum, June 1981; Draft Environmental Assessment, February 1981, and a Final Environmental Assessment, June 1981. The new wholesale power rate schedules are based on results of the final studies that appropriately reflect public comments, criticisms, and suggested alternatives.

Repayment Study

BPA is required by law to set its rates so as to recover the costs of production, acquisition, conservation, and transmission of electric power, as well as the irrigation costs required to be repaid with power revenues, over a reasonable period of years; to recover other costs and expenses incurred pursuant to the Regional Act and other provisions of law; to pay the principal premiums discounts, expenses, and interest in connection with bonds issued on behalf of BPA; and to make payments to the credit of the Reclamation Fund required to be paid from electricity sales. It must also provide the lowest possible rates to consumers consistent with sound business principles (Section 5 of the Flood Control Act of 1944 and Section 9 of the Federal Columbia River Transmission System Act). Reclamation projects must be scheduled so that the required assistance from power revenues will not average more than \$30,000,000 in any period of 20 consecutive years.

The Department of Energy repayment policy is set forth in Department of Energy Order No. RA 6120.2, dated September 20, 1979, which replaced Department of the Interior Policy, 730 DM 3 and 4, without substantive change. BPA's annual revenues must be sufficient to pay all annual operation and maintenance costs, purchased power costs, interest expenses, and annual costs of bonds issued on behalf of BPA. Reasonable periods of years during which repayments must occur have been specified to be 50 years for Federal hydroelectric generating plants, and within the average service life of the facilities (up to a maximum of 50 years) for the transmission system and replacements. Irrigation assistance must be provided within the periods established for the irrigation water users to repay their share of construction costs. Each annual increment of investment must be amortized within its prescribed period. To the extent possible, while complying with the established repayment periods, revenues available for amortization will be applied to the highest interest-bearing investments first to minimize interest expenses.

BPA's transmission investments are repaid within 35 years after the facilities have been placed in service; original Federal investments in generating projects must be repaid within 50 years after the project begins producing revenues; replacements must be repaid within their estimated service lives up to a maximum of 50 years; and the repayment periods for interest-free irrigation investments range from 40 to 66 years.

The adequacy of revenues from existing power and wheeling rates to meet these cost recovery criteria is determined by preparing a current power system repayment study. This study projects estimated revenues and costs for the entire power system over the remainder of the repayment periods for major investments to determine if there will be enough revenue to recover all costs. The allowable unamortized investment for any given year is the maximum investment that can remain unamortized in that year if the repayment periods

established for each power facility are observed. Each year, the amount of new power investment made that year is added to the allowable unamortized investment.

The power repayment study determines whether the repayment criteria are met by showing annual revenues and expenses and by comparing the estimated future unamortized power investment with the allowable unamortized investment. If the unamortized investment exceeds the allowable amount for any year, an increase in revenues will be necessary to assure complete recovery of all power costs within the required repayment period.

Cost-of-Service Analysis

The Cost-of-Service Analysis (COSA) was used to determine the average cost of providing power to each of BPA's classes of service. BPA followed generally accepted utility methods in preparing the study, although modifications were made to reflect the repayment method used by Federal power marketing agencies to determine revenue requirements. While the results of the COSA were used extensively in the design of rates, final rates also reflect adjustments in costs based on the results of the other studies, as well as considerations of value of service, equity, continuity of rates, and ease of administration.

In addition to providing information on the cost of serving various customer classes, the analysis was designed to respond to Section 10 of the Federal Columbia River Transmission System Act which requires that "the recovery of the cost of the Federal transmission system shall be equitably allocated between Federal and non-Federal power utilizing such system."

Three major steps were followed in preparing the COSA. First, investment and annual costs were divided according to functions performed by the power system. These functions were defined as generation, transmission, and metering and billing. Second, generation costs were classified to energy and capacity. Third, functionalized and classified costs were allocated to the service classes. The service classes include power rates, wheeling rates, other services, and miscellaneous services and revenues. The power rate category was further divided into the subcategories of priority firm power, reserve power, industrial firm power, modified firm power, annual and seasonal firm capacity, new resource firm power, and nonfirm energy.

Long-Run Incremental Cost Analysis

The BPA Long Run Incremental Cost (LRIC) Analysis is a cost-of-service analysis which focuses on the incremental costs incurred to meet load growth requirements or the costs saved by not consuming additional increments of power. This analysis differs from an average cost-of-service analysis where the primary function is to reflect the costs which a utility is required to recover based on particular accounting practices. BPA conducted the LRIC Analysis to obtain important information on the direction of future costs and rates.

The LRIC Analysis focuses on the costs BPA will incur during a planning period through 1989, adjusted to a 1982 constant price level. Included in the study are costs for constructing, operating, and maintaining new Federal generation and transmission facilities and costs associated with the Washington Public Power Supply System nuclear plants.

The LRIC of generation capacity is based on hydro peaking units added to the FCRPS through 1989. The long run incremental cost of energy is based on the cost associated with the net-billed portions of the Washington Public Power Supply System projects Nos. 1, 2, and 3. The LRIC of transmission is based on the cost of Federal transmission facilities added over the planning period to serve load growth and to provide transmission services for the movement of power for other utilities.

Time-Differentiated Pricing Analysis

The Time-Differentiated Pricing Analysis (TDPA) differentiated both incremental and embedded costs by time period. Separate analyses were conducted for capacity costs and for energy costs. The study results show that BPA's embedded historical costs for capacity vary over the year, with three separate distinguishable periods. The three capacity periods are: (1) December through May, Monday through Friday, 7 a.m. to 10 p.m. (winter); (2) June through November, Monday through Friday, 7 a.m. to 10 p.m. (summer); and (3) all remaining hours of the year (offpeak). Saturday is an onpeak day in BPA's current rates, but the study indicates that it is now marginally offpeak.

The energy analysis of embedded historical costs indicates that there are two periods in which costs vary. There is a summer season from April through August and a winter season from September through March. The cost differences for these two periods are based on costs associated with storage of water used primarily to generate energy during the winter season.

Wholesale Power Rate Design Study

The Wholesale Power Rate Design Study (WPRDS) shows the development of the final rate schedules through a series of rate design steps. The Repayment Study and the COSA provide the foundation for the development of the rate levels. The LRIC Analysis provides a guide for developing rates from an economic efficiency perspective. The TDPA is used to design rates which reflect time-differentiated costs. The WPRDS shows how the cost information produced by the COSA is further treated to reflect several cost adjustments relating to fixed contractual obligations, credit of non-firm energy revenues, time differentiation of costs, recovery of other costs, and other adjustments which achieve rate design objectives.

Staff Evaluation of the Official Record and Addendum

The Staff Evaluation of Official Record notes and discusses each major comment received during the

public involvement process. The staff evaluation contains an outline of the issues raised in response to the February 1981 rate proposal and details BPA's assessment of these issues. All issues are combined by generic category.

In June 1981, BPA updated the evaluation with an Addendum to the Staff Evaluation of Official Record. The Addendum details comments received since mid-May 1981, related to BPA's interim transmission arrangements. As in the main staff evaluation, it includes BPA's assessment of the issues raised.

Rate Environmental Assessment

The Draft (February 1981) and Final Rate Environmental Assessment (EA) (June 1981) were used by BPA to identify and analyze alternative revenue levels and rate designs. In addition to the 78.5 percent revenue increase, the EA identified two lower revenue level alternatives (no change and 30 percent revenue increase) and one revenue alternative based on the LRIC Analysis which represented a 720 percent increase. The EA described each alternative revenue level, quantified the alternative, reviewed the effects of the alternative on BPA, its customers, and the ultimate consumers of the region, and analyzed the environmental impact of each alternative. The Rate EA also contains a discussion of rate design alternatives and their probable impacts.

DISCUSSION

Revenue Requirement Issues

The power repayment study determines the total revenues which must be collected from rates, excluding revenues associated with the costs of the exchange resources to be acquired from investor-owned utilities and paid for by the direct-service industrial customers. Issues on revenue requirements relate to forecasts of revenues and costs and to methods used in repayment analysis.

Accuracy of Forecasts

Revenues

Comments received regarding the initial revenue forecast included concerns that the projected loads needed to be updated; that revenue from the sale of power purchased to meet firm load deficits was not included in the forecast; and that there was a discrepancy in the purchased power expense included in the initial Repayment Study and COSA. In the final Repayment Study, BPA used updated load data. Additional adjustments were also made to public agency loads including a reduction of 492 average megawatts to reflect historical differences between projected and actual loads, and a 46-megawatt reduction to public agency loads for conservation.

While earlier versions of the Repayment Study did not include revenues from the sale of power purchased to meet firm load deficits for investor-owned utilities, rates were applied to those loads in the final revenue

forecasts to show that the rates recover revenues sufficient to meet repayment criteria.

The discrepancy in purchased power expense between the Repayment Study and the COSA has been corrected. The purchased power expense in the final Revised Repayment Study is now compatible with expenses in the COSA.

Under critical water conditions, BPA now projects the purchase of 491 average megawatt at a total cost of \$159.9 million, plus the purchase of 208 average megawatts of power from Portland General Electric's (PGE's) Boardman plant for \$88.1 million. The power purchase forecast under average water conditions is 266 average megawatt at a total cost of \$104.7 million, plus the cost of purchasing power from PGE's Boardman plant of \$73.8 million. The cost estimate under average water conditions was incorporated in both the final Repayment Study and Cosa.

The basis for the forecast of nonfirm revenues is the secondary energy analysis which projects sales of nonfirm energy by month for 40 historical water years to determine averages. For the initial proposal, this analysis projected regional sales of nonfirm energy and applied percentages to the regional markets to approximate Federal sales and Federal nonfirm energy sales revenues. Several comments were received indicating that a Federal secondary energy analysis rather than a regional analysis would be a more appropriate and accurate method of determining Federal nonfirm resources, revenues, and the level of sales to the various markets. For the final Repayment Study, a Federal secondary energy analysis was prepared. The analysis assumes displacement of short term power purchases required to serve the firm loads, the shifting of firm energy load carrying capability to serve the top quartile of the direct-service industrial load for 6 months of the year, service to the top quartile for the remainder of the year with nonfirm energy when possible, and the subsequent sale of remaining nonfirm resources to the various secondary energy markets.

Other comments received on the initial secondary energy analysis indicated some discrepancies between that analysis and the analysis used in the determination of purchased power for FY 1982 for the initial proposal. Specifically, an analysis assuming load growth over the critical period was made to determine the secondary energy available to displace power purchases, while an analysis assuming no load growth was made to estimate secondary energy sales. Also, the reduction in secondary available for sale due to shifting the firm energy load carrying capability was not reflected in the initial revenue forecast. Both of these discrepancies have been corrected in the final revenue forecast.

The revenue forecast is affected by how available energy is used. Representatives of the Public Power Council maintained that BPA's assumed use of hydroelectric energy which is in excess of a critical-year supply to displace power purchases proportionally for

both the Federal base system and new resource pools is inconsistent with the preference clause of the Bonneville Project Act. These parties argued that preference extends to nonfirm energy as well as firm energy. Preference does extend to nonfirm energy, but energy is only nonfirm when it is not needed to serve firm or quasi-firm loads. Using hydroelectric energy which exceeds a critical year supply to displace BPA's most expensive purchases is more cost-effective than the sale of those resources to the quasi-firm top quartile of the direct-service industrial load or to the nonfirm energy markets. If only a portion of power purchases can be displaced, the highest incremental cost resources will be displaced first to maximize fuel cost savings. Operationally, BPA does not differentiate between purchases for the Federal base system deficits and those for the new resource pool deficit. Power purchases are made only to the extent necessary to serve firm loads. To the extent that Federal resources are available to meet those commitments, power purchases will not be made.

The revenue forecast used in the Repayment Study submitted to the parties in late April assumed that the firm energy load carrying capability of the hydro system would be adjusted to provide service to the top quartile of the direct-service industrial customers for the first 6 months of the operating year. As stated above, it was also assumed that hydroelectric energy in excess of a critical year supply would be used to provide service to the top quartile before it would be sold in the various nonfirm energy markets. Representatives of the region's private and publicly-owned utilities contended that an adjustment of the firm energy load carrying capability to provide service to the top quartile of the direct-service industrial load is not permitted under the Coordination Agreement of 1964 because the top quartile is not a firm load as defined in the Regional Act.

In accordance with the Regional Act, the top quartile is considered a firm load for operating purposes and provides operating reserves for BPA which may be restricted at any time in order to protect firm loads within the region. BPA is obligated to operate to serve the top quartile as if it were firm, the sale of energy to the direct-service industries is not a nonfirm sale, although the top quartile is interruptible to protect firm loads. The adjustment of the firm energy load carrying capability to serve the top quartile load of the direct-service industries is therefore proper, and the preference provisions of the Bonneville Project Act and the Regional Act are not violated by serving the top quartile load prior to serving the nonfirm energy markets.

In the initial proposal, BPA estimated that a reduction of approximately 150 megawatts in firm energy loads would occur as a direct result of expenditures on conservation programs and the granting of billing credits. The total impact of this estimate was not reflected explicitly in the revenue forecast. Representatives of the InterCom-

pany Pool indicated that the revenue forecast would be more accurate if BPA adjusted firm loads to account for the impact of conservation programs. This is important because it has an impact on the overall rate of load growth used in the revenue forecast as well as on the level of rates. BPA subsequently recalculated the costs and anticipated reductions in load associated with each of the programs. Current projected loads of the investor-owned utilities already reflect anticipated conservation program benefits. However, the projected loads of the public utilities and cooperatives do not incorporate a load adjustment reflecting these conservation programs. Consequently, the projected firm energy loads and revenues associated with the loads of the public utilities have been reduced by the projected amount of conservation.

Escalation

The Repayment Study supporting the initial power rate proposal used an annual 12-percent escalation rate. Representatives of the InterCompany Pool questioned the appropriateness of the 12-percent rate. Upon reconsideration, BPA determined that the Fiscal Year 1982 Budget Gross National Product deflator rate was the most appropriate rate to use, since it is widely used in the Federal government and because it is representative of the results of several other indices. Consequently, escalation rates for FY 81 and FY 82 of 10.5 percent and 9.3 percent, respectively, were used in the final Repayment Study. BPA rejected use of the revised Fiscal Year 1982 Gross National Product deflator as too low an inflation estimate for electric utilities which typically experience inflation in excess of general indices.

Washington Public Power Supply System (WPPSS)

The Repayment Study supporting the initial power rate proposal included the costs of bonds issued for WPPSS Nuclear Project Nos. 1 and 2 after July 1, 1982. Representatives of the State utility commissions suggested that the Repayment should exclude costs for WPPSS Nuclear Projects Nos. 1 and 2 that occur beyond the test year. This suggestion seemed appropriate and was adopted. The cost of bonds issued after July 1, 1982 were excluded in the final Repayment Study.

Methodology

The existing Repayment Study methodology incorporates the principle of repaying high interest-bearing investments first to the extent possible while repaying every investment within its repayment period. In addition, capitalized deferred expenses must be paid prior to the amortization of any Federal investment. These policies are established in DOE Order RA 6120.2, section 8, part C(3).

Parties to the rate hearings raised three major concerns with respect to the Repayment methodology: (1) whether the study could determine the minimum revenue requirement that would recover costs, (2) what the potential future impacts of amortizing high interest-bear-

ing investment first would be, and (3) whether the priority given to the payment of deferred capitalized expenses was appropriate.

The optimization feature of the Repayment Study computer program determines the lowest revenue level that satisfies the cost recovery criteria within one-tenth of one percent. Given the numerous estimates inherent in a rate filing, a further refinement of this level of accuracy is not warranted. This computer program has been reviewed extensively to assure that it accurately performs the required calculations.

It is true that the policy of repaying highest interest-bearing investments first compresses the period in which lower interest-bearing investments are repaid. However, this does not increase the likelihood that a substantial increase in rates will be needed in the future to repay the low interest-bearing investments. The only reasons for additional rate increases in the future will be additional investments or higher operational costs that are not reflected in the present rates.

With respect to the concern that the payment of capitalized deferred expenses ahead of repaying Federal investments is inconsistent with minimization of rates, it is true that indefinitely deferring these expenses would reduce rates as long as interest rates on bonds are higher than the current interest rates used to capitalize deferred expenses. By the same reasoning, rates would be lower if BPA continued to defer paying annual expenses and used its revenue to retire the higher interest-bearing bonds instead. However, the statutory requirement is not to minimize rates; but rather to set them as low as possible consistent with sound business principles. The payment of annual expenses must have priority to comply with sound business principles.

Other Revenue Requirement Issues

Other revenue requirement issues are discussed in the Staff Evaluation of Official Record and the Administrator's Record of Decision.

Cost-of-Service Analysis Issues

Because the results of the COSA impact final rates, BPA received a significant number of comments on the methods that were used in preparing this study. The comments that were received concerned alternative interpretations of the Regional Act with respect to defining rate pools, the division of costs between capacity and energy, segmentation of transmission costs, and allocation of costs to various classes of service.

Rate Pools

The primary concern raised with respect to BPA's interpretation of Sections 7(b), 7(c), and 7(f) of the Regional Act revolves around the issue of the allocation of the cost of the three resource pools to rate pools. The three resource pools are distinguished as (1) Federal base system resources; (2) resources acquired through the Section 5(c) residential exchange; and (3) any additional new resources acquired by the Administrator. Three rate pools are also defined in the Regional

Act. Section 7(b) directs the Administrator to set a rate applicable to the preference customer and residential/rural exchange loads. Section 7(c) provides for the rate or rates applicable to the direct-service industries, and the rates provided for in 7(f) will be applicable to new large single loads of the preference customers and for service to investor-owned utilities' deficits in the previous year plus any load growth for the current year.

A sufficient amount of Federal base system resources has been assigned to the 7(b) rate pool to serve the entire 7(b) load. The proportionate cost of these resources was the basis for determining the PF-1 rate. A small amount of Federal base system was not required to serve 7(b) loads. The costs of the remaining portion of Federal base system resources, and all the costs of resources acquired through the residential exchange were assigned to be recovered from the 7(c) loads. These costs were the basis for determining the IP-1 and MP-1 rates. The 7(f) loads were assigned the costs of all additional new resources. These costs formed the basis for the NR-1 rate.

The InterCompany Pool contends that this assignment inappropriately grants a special "junior preference" to the direct-service industries and conflicts with both the intent of the Regional Act and its legislative history. The InterCompany Pool advocates two cost pools, the first of which would be identical to those costs assigned to the 7(b) rate pool established by BPA. The second pool, however, would consist of the costs of all remaining resources. This cost pool would provide the base for developing the rate that would be used to serve the direct-service industries, as well as the new resource rate which would apply to new large single loads of preference customers and to the power supply requirements (including deficits and load growth) of the investor-owned utilities. Section 7(f) of the Regional Act grants to the Administrator discretion in the determination of the appropriate assignment of resource costs to the new resource rate pool. In addition, the legislative history of the Regional Act supports the method of cost assignment proposed by BPA rather than the method proposed by the InterCompany Pool by continually referring to the 7(b) rate as the "new resources rate" and indicating that such rate would "likely to be at the marginal cost of power."

Another issue raised by the InterCompany Pool relates to the potential willingness of utilities to sell resources to BPA for inclusion in the New Resource pool. It was suggested that by assigning the costs of conservation and billing credits to the new resource pool, in the absence of a corresponding assignment of the load reduction associated with conservation to that pool, BPA would create a situation in which the resulting new resource rate would exceed the average cost of new resources. Under these circumstances it would not be cost effective for utilities to sell new resources to BPA as intended under the Regional Act.

No allocation of billing credit costs to the New Resource cost pool is made in developing the final rates, and both the costs and the load reductions associated with conservation on investor-owned utility systems are being assigned to that pool. Reducing load in the New Resource pool reduces the need for higher cost purchase power. In most cases it is estimated that the cost of conservation programs funded by BPA will be less than the cost of new resources added to the New Resource pool. Finally, the use of Federal secondary resources to meet a portion of the New Resource pool load will further reduce the NR-1 rate to a level that is expected to be attractive to utilities that are developing resources.

Definition of the Federal Base System and Allocation of Short-Term Purchase Power Costs

Several preference customer representatives have suggested that BPA should not have allocated deficit purchase power costs to the Federal base system pool in view of the fact the Federal base system resources are more than adequate to meet the 7(b) pool loads. In the absence of the Regional Act, BPA would have been making purchases to serve the firm loads of the preference customers and the direct-service industries. Those purchase power costs would have been allocated proportionately on the basis of load to the preference customers and the direct-service industries. The Regional Act was not intended to remove from the preference customers the responsibility for sharing a portion of the cost of meeting BPA's deficit.

It was further suggested that BPA would be circumventing the resource acquisition procedures of the Regional Act by proposing use of its short-term purchase authority under the Transmission System Act to meet its deficit. However, Section 6(a)(2) of the Regional Act specifically recognizes the Administrator's right to make short-term purchases under the Transmission System Act and places no restrictions on that authority.

Energy reserves are provided to BPA through the rights BPA has to restrict the second quartile of the direct-service industrial customer load. Another suggestion regarding assignment of purchase power costs was that BPA should restrict direct-service industrial second quartile loads before purchasing power to meet priority firm loads. The purpose of a reserve is to serve as a resource of last resort, and the value of the reserve is the right to restrict. Once the restriction is exercised, its value is lost and the reserve must be reestablished as quickly as possible. The reserve is intended to function not as an economical alternative to other resources, but as a final backup that can be relied on to protect the quality of firm service.

A final concern expressed relates to the use of Federal hydroelectric energy to meet a portion of the deficit assigned to the New Resource pool. Preference customer representatives have suggested this would violate the preference clause by depriving them of their preference to nonfirm energy. They also suggest this would represent a

change in BPA's nonfirm energy policy. Under the Regional Act, BPA's deficit is a regional deficit and the Administrator must seek to meet it in an economically prudent manner. The use of available hydroelectric resources to meet a portion of this deficit is reasonable and proper and is not a violation of the preference clause. Furthermore, the use of this energy to offset a portion of the regional deficit is not in conflict with, or a change in, BPA's policy on nonfirm energy.

After BPA meets its firm and quasi-firm load obligations secondary energy becomes available which BPA then markets based on its secondary energy policy. This policy provides a maximum amount of decision flexibility in order to insure that specific goals can be met through the sale of secondary energy, and does not set forth procedures by which the goals are to be achieved. The goals of the secondary energy policy include (1) encouragement of widespread use, (2) compliance with Public Law 88-552, (3) distribution of the benefits of nonfirm sales to all ratepayers in the region, (4) consideration of existing market conditions, (5) minimization of effects on fish and wildlife, (6) consideration of the purpose or use to which nonfirm energy would be put, (7) encouragement of conservation and renewable resource development, (8) conformity to National Energy Policy, and (9) subordination of revenue maximization to the foregoing objectives.

Allocation of Conservation Costs

Several concerns were raised regarding the appropriate method for allocating both the costs and projected load reductions associated with conservation programs. One suggestion was that it would be best to use a uniform allocation of conservation costs across all energy use, given the lack of information currently available concerning the future distribution of conservation benefits. A number of parties have suggested that both the costs and the load reductions associated with conservation should be assigned to those customers whose loads are being reduced through the conservation programs. This alternative is consistent with BPA's treatment of conservation in the final rates. The load reductions and costs associated with conservation programs funded by BPA on preference customers' systems have been assigned to the Federal base system pool. The load reductions and costs associated with conservation programs funded by BPA on investor-owned utility systems have been assigned to the New Resources pool.

Classification of Generation Costs

Since differences exist in the purpose and operation of hydro facilities and thermal plants, these facilities were classified separately. The direct service industries have suggested that this is inappropriate and argued for application of a fixed/variable cost method to all generation costs. Other parties have agreed with the general BPA approach but suggest that additional costs be classified to energy. The fixed/variable approach would result in classification of virtually all hydroelectric

generation costs to capacity as well as most thermal generation costs to capacity. The fixed/variable approach would not reflect the capacity and energy relationship developed during the planning of a hydro system. In either case, a number of necessarily subjective decisions must be made in arriving at the resulting classification percentages. The potential problems associated with the cost causation approach are greatly exceeded by the failure of the fixed/variable approach to appropriately reflect the operational and planning characteristics of the Federal Columbia River Power System. The problem with a fixed/variable approach is that it classifies capacity and energy strictly from an operational standpoint and completely disregards why the costs were incurred initially. The Federal Energy Regulatory Commission has indicated general support for the classification scheme used by BPA in its order remanding BPA's 1979 Wholesale Power Rates without prejudice (45 FR 79545, 79548).

Segmentation

In order to enhance the equity of transmission system cost allocation and to insure compliance with the requirement of the Transmission System Act to equitably allocate Federal transmission costs between Federal and non-Federal power, BPA's transmission costs were separated into seven segments. These segments consist of (1) generation integration, (2) integrated network, (3) intertie, (4) fringe area, (5) preference customer delivery, (6) direct-service industrial delivery, and (7) investor-owned utility delivery.

Two concerns have been raised pertaining to segmentation. First, it was suggested that any lines over 69 kV that serve only a direct-service industry load should be assigned to that direct-service industry delivery segment rather than to the integrated network. BPA has not included lines above 69 kV leading from integrated network or fringe substations to investor-owned utilities or preference customer substations in the delivery segments for those customers. To follow the suggested procedure for lines serving direct service industries only would constitute unwarranted class discrimination. In addition, lines above 69 kV serving only a direct-service industry usually have a higher capacity than the substations they serve. The lines are expected to be extended to serve other substations and customers at some future time. To assign the total costs of these lines to the delivery segment of an existing customer would result in an inequitable overallocation of costs to that customer's service class.

The second concern regarding segmentation related to general validity of BPA's segmentation method. It was suggested that studies of actual coincident power flows or coincident peak loads would better reflect actual facility use. Such approaches may be valid alternatives to the approach used, but are not necessarily preferable. BPA's approach is consistent with a cost causation approach to cost assignment and validly reflects a close approximation to actual use of facilities.

Allocation of Costs to Classes of Service

Energy-related costs were allocated among the classes of service in direct proportion to the kilowatthours of energy associated with each class. No adverse comments were received concerning this standard method of allocating energy-related costs.

Capacity-related costs were allocated according to the 12 coincidental peak (12 CP) method. The 12 CP method results in allocation of capacity-related costs to each customer class in proportion to the projected coincidental peak demands for the class, averaged over the 12 months in the test year. The use of coincidental rather than noncoincidental peak appropriately reflects the benefits that accrue to the system as a whole because of customer diversity.

Several concerns about the method of allocating capacity costs have been expressed. The direct service industries suggested that use of a 12 CP allocation method for capacity related costs is inconsistent with BPA's Time Differentiated Pricing Analysis and results in an excessive allocation of these costs to high load factor customers. The Time-Differentiated Pricing Analysis does indicate there should be a seasonal differentiation of generation capacity costs. Therefore, the seasonal load amounts are used to allocate the generation capacity costs among classes of service. This rate design step effectively replaces the use of the 12 CP allocation method for generation capacity costs.

A final concern expressed over the 12 CP method related to the use of maximum noncoincidental demand in some cases and average demand in others to develop non-coincidental demands. It was suggested that such a procedure might produce a biased allocation. Since BPA's coincidence factors are based on average demand, the use of average demand in those cases where no forecast is available for maximum noncoincidental demand would not produce a biased allocation of capacity costs.

Allocation of Exchange Resource Costs

In the initial 1981 rate proposal, BPA assumed that the residential exchange loads had a load factor of 100 percent. It followed that the exchange resources were also at a 100 percent load factor. A number of parties expressed concern over the appropriateness of this assumption. Consequently, the allocation of exchange costs is now based on the ratio of the preference customers' 12 CP to their average energy requirement. The energy requirement of the exchange load is then multiplied by this ratio to arrive at a 12 CP estimate for the exchange costs. Therefore, the resulting allocation is a reflection of the load factor of the preference customers. This procedure is the best and most reasonable method currently available to BPA for allocating the exchange costs.

Some parties have suggested that the costs of the exchange should be treated as an accounting transaction rather than a resource transaction. The direct-service industries have further suggested excluding the treatment

of these costs from the COSA. They indicate this would avoid the unnecessary introduction of estimating errors relating to the load factor and average system cost assumptions into the analysis. The Regional Act requires BPA to treat the exchange resources as a resource acquisition and grants the Administrator the authority to make the appropriate allocation. The inclusion of the exchange resources in the COSA is necessary in order to arrive at an appropriate allocation of the cost of the Federal transmission system as well as the exchange resources.

Allocation of Fish and Wildlife Expenses

In BPA's initial proposal, the cost of facilities associated with the mitigation of impacts to fish and wildlife by hydroelectric plants were assigned to all power users, based on the assumption that these mitigation efforts would benefit all citizens of the region, rather than just those served by Federal base system resources. It was suggested by a representative of the InterCompany Pool that the need for mitigation facilities at hydroelectric plants was directly related to the plants themselves and should be included as a cost of the plants and be recovered from customers supplied by the plants. The Regional Act provides for the collection of costs for fish and wildlife mitigation through power rates. The Regional Act does not indicate that this cost should be collected only from customers served by hydroelectric facilities. It is anticipated that at least a portion of the expense associated with fish and wildlife may be directed toward programs which are unrelated to the effects of hydro plants. As the programs for which these expenses are incurred become better defined, it may be possible to develop a more disaggregated allocation of these costs for future rate filings.

Allocation of Intertie Costs

The costs of the Pacific Northwest/Pacific Southwest Intertie have been allocated to nonfirm energy service and various intertie transmission services. The portion of intertie costs assigned to nonfirm energy reflects the fact that an original purpose for construction of the intertie was the transmission of nonfirm energy. A representative for Pacific Gas and Electric has suggested that BPA's allocation of transmission capacity costs to nonfirm energy is inappropriate in view of the fact that nonfirm energy purchasers enjoy no capacity rights. Additional concerns voiced by Southwest representatives relate to the consideration given to intertie functions other than transmission of nonfirm energy in allocating intertie costs.

The allocation of a portion of the intertie costs to nonfirm energy, based on cost causation and operational use, it is not intended to reflect any entitlement by nonfirm energy purchases to transmission capacity rights. The intertie costs not assigned to nonfirm energy were allocated to seasonal capacity, formula power transmission, the Columbia Storage Power Exchange, capacity/energy exchange, and non-firm energy trans-

mission. This allocation appropriately reflects the services provided by the intertie.

Other Cost-of-Service Issues

Other cost-of-service issues are discussed in the Staff Evaluation of Official Record and the Administrator's Record of Decision.

Long Run Incremental Cost Issues

The Long Run Incremental Cost (LRIC) Analysis is a cost-of-service analysis focused on incremental costs either incurred to meet load growth requirements or saved by not meeting an additional increment of load. The LRIC Analysis provides the basis for the classification of certain generation costs between capacity and energy and for certain rate design adjustments.

Combustion Turbine Analysis

In the initial proposal BPA indicated that while combustion turbines were the traditional least cost source of peaking capacity for utilities in general, hydro peaking units were selected. The rationale was that BPA did not have the authority to acquire combustion turbines and that hydro units were already being constructed to meet the increase in peaking demands. An analysis of the difference between the LRIC of capacity based on a combustion turbine or a hydro peaking unit indicated that the difference in cost was not significant, with combustion turbines being the higher cost of the two. With the passage of the Regional Act and BPA's new resource acquisition authority, the combustion turbine issue received significant comment during the hearing process. The comments directed to the analysis of a simple cycle combustion turbine indicated the following: (1) the reserve factor used was inappropriate; (2) the price of oil was low; (3) the capacity factor was high; (4) the interest rate used to capitalize investment was high; (5) the energy produced while using the combustion turbine should be valued; and (6) the cost of a combustion turbine should be used by BPA as the basis for the long run incremental cost of capacity.

The reserve factor applied in the combustion turbine analysis was not intended to be resource specific but to represent the reserve factor that would be applied to an additional increment of generating capacity regardless of the source of the capacity. The portion of the reserve factor related to the hydro realization adjustment is not appropriate for analyzing a combustion turbine and consequently, it has been excluded from the reserve factor used in the combustion turbine analysis for the final study.

The price of oil developed for the analysis did not accurately reflect the current projected market prices for the test year. The oil price data submitted in testimony by the Public Generating Power Pool and Snohomish County Public Utility District has been used in the final analysis, and the average price for 1980 has been escalated to 1982 dollars.

The capacity factor used in the final analysis is 7.5 percent. This rate is supported by the Federal Energy Regulatory Commission that recommends use of a capacity factor of 7.5 percent for combustion turbines when evaluating hydroelectric power.

The interest rate applied to the capital cost was 12 percent, which represents the incremental rate at which BPA can borrow money from the U.S. Treasury. The analysis assumes that BPA would be funding the combustion turbine and, consequently, the 12 percent rate of interest is appropriate.

There appears to be a point at which continued operation of the turbine would be for the purpose of providing energy and that a credit is needed to offset these costs. To determine the energy credit, an iteration process was used. This resulted in an energy credit of 60.8 mills per kilowatthour applied to the variable costs of the simple cycle combustion turbine for the final analysis.

With the energy credit applied, a 7.5 percent capacity factor, the higher fuel cost, and the revised reserve factor, the long run incremental cost of a combustion turbine is \$61.09 per kilowatt. This result supports BPA's use of the chosen hydro units to determine the long run incremental cost of capacity of \$55.32 per kilowatt.

Capacity

Many comments were received regarding the long run incremental cost of capacity. Some of the comments indicated that BPA should not include certain peaking units in the LRIC Analysis. Another issue concerned the appropriate value for the energy produced by the hydro peaking units. For the final LRIC Analysis, the number of peaking units included in the LRIC of capacity was expanded to include all existing and planned peaking units through FY 1989. Costs for existing units were escalated to FY 1982 dollars. This expansion increased the sample size and will lead to increased stability in the LRIC of capacity. In addition, four of the Bonneville Second Powerhouse units and the Libby Reregulating Dam units are excluded from the LRIC of capacity determination. This change ensures that only those units considered to be entirely peaking units, i.e., no incremental energy produced, are included in the LRIC of capacity determination.

Energy

BPA received several comments on the LRIC of energy determination. Some comments indicated that BPA should base its LRIC of energy determination on the costs of WPPSS Nos. 4 and 5 instead of WPPSS Nos. 1, 2, and 3, or if not WPPSS Nos. 4 and 5, then WPPSS No. 3 should be the only unit used. BPA used the costs of WPPSS Nos. 1, 2, and 3, adjusted to FY 1982 constant dollars and averaged over the three units, as the basis for the LRIC of energy. In this way, BPA developed costs for a representative additional thermal baseload plant.

Other comments concerned the costs included by BPA for the LRIC of energy determination. It was re-

commended that waste disposal, decommissioning, and environmental costs related to nuclear power production facilities be included. BPA agreed that all quantifiable costs related to a facility should be included in the LRIC determination. BPA decided that certain costs such as waste disposal and environmental costs will require further study before they can be included in the LRIC Analysis. However, for the final LRIC Analysis, BPA included projected costs for decommissioning WPPSS units 1, 2, and 3 in the determination of the LRIC of energy.

Rate Design Issues

The results of all the other studies described in this order plus the following rate design objectives were used to develop the final rates: (1) total revenues must be adequate to meet total repayment obligations; (2) the cost burden must be distributed in an equitable manner among recipients of the service; (3) rates must be designed to encourage conservation and minimize environmental impacts; and (4) rates must be designed to encourage efficient use of the Federal Columbia River Power System by reflecting costs incurred and benefits received. Consideration also was given to rate continuity, ease of administration, revenue stability, and ease of understanding.

Adjustments to Reflect Long Run Incremental Costs

Three rate schedules (NF-1, nonfirm energy; CF-1, firm capacity; and ET-2, energy transmission) are expected to produce revenues in excess of allocated costs. These revenues have been credited to transmission and generation capacity costs. In the final study, a credit of \$91.421 million was applied to Federal base system summer generation capacity costs and \$29.857 million were applied to the new resources summer generation capacity costs. Transmission capacity cost credits were applied to the transmission portion of wholesale power costs (\$26.814 million) and to the wheeling rates (\$4.214 million).

The crediting of excess revenues to capacity costs reflects the incremental cost relationship between capacity and energy which is developed in the LRIC Analysis. The cost relationship between capacity and energy is changing as BPA purchases the output of new thermal plants. By comparing the results of the COSA with those of the LRIC analysis, this changing relationship is evident. These studies show that although all costs are increasing, the costs of supplying energy are increasing at a faster rate than the costs of supplying new capacity. The ratio of the LRIC demand rate to the average demand rate is 3.1 to 1, while the ratio of the LRIC energy costs to the average energy costs is 10.6 to 1.

A comment was received that suggested the excess revenues be credited to energy instead of capacity. The reason offered was that NF-1 sales are energy-only transactions and have no effect on system peaking capability presently or in future years. This suggestion was not adopted because it is important to reflect the changing cost relationship between capacity and energy.

Time-Differentiated Pricing

BPA received many comments on the Time-Differentiated Pricing Analysis and incorporated some of these comments into the design of the new rate schedules. Rate schedules PF-1, NR-1, IP-1, and MP-1 contain both daily and seasonal differentials in the capacity rate and a seasonal differential in the energy rate.

BPA received comments questioning the method selected to determine seasonal and diurnal capacity periods. It was suggested that BPA should not have based the selection of seasonal capacity pricing periods on probability of negative margin data and that a more appropriate method would entail an analysis of monthly peak load data. The probability of negative margin method was criticized because the results can be influenced by the scheduling of maintenance. It was noted that probabilities of negative margin can be shown during months with high scheduled maintenance even though capacity requirements are much less during these months than during other months of the pricing period. Use of the suggested alternative method may result in different pricing periods. Additionally, some customers and customer groups argued that the daily peak period is too long to allow effective shifting of the load to the off-peak period.

Monthly peak load data are inadequate for determining pricing periods because these data reflect only demand for power. Probability of negative margin data take into account both the projected demand for capacity and the monthly availability of resources considering hydrological conditions, hydro and thermal capacity, and maintenance. While the probability of negative margin is influenced to a certain degree by maintenance schedules, it still represents the best indicator of appropriate time periods for developing rates. Moreover, probability of negative margin reflects both the supply of and demand for electricity, and this is preferable to examining only one side of the relationship, as is the case with using only load or generating data.

Federal base system, new resource, and exchange resource costs are time differentiated. Although rates are based on average costs, offpeak generation capacity and transmission costs are set at zero to reflect the fact that the time-differentiation of long run incremental capacity costs finds these costs to be incurred solely in response to additional peak period usage. Generation capacity costs are apportioned to the winter and summer weekdays with Saturday included in the peak period based on the relative distribution of embedded costs to these time periods. Energy costs associated with the three resource pools are apportioned to the September through March (winter) and April through August (summer) periods based on the distribution of Federal base system energy costs. Specifically, 62.8 percent are assigned to the winter period and 37.2 percent to the summer period.

BPA received four types of comments on these decisions. These included: (1) the logic for including Saturday in the peak period is invalid; (2) the structure of long run incremental cost has not been sufficiently incorporated in the design of time-differentiated rates; (3) demand charges based on time-differentiated noncoincidental peaks do not properly reflect cost causation; and (4) the legitimacy of time-differentiating new resource and exchange costs on the basis of a Federal base system analysis is open to criticism.

The Time-Differentiated Pricing Analysis presented evidence that Saturday is marginally offpeak. Saturday's peak hours during FY 1975-79 average much closer to Sunday's than weekdays. This is a different statement than saying that Saturday is identical to Sunday or that daytime loads on either day are less than average nighttime loads. Statistically, this analysis shows that Saturday's peak was greater than Sunday's, but closer to Sunday than weekday's. Clearly, Saturday daytime loads belong to an intermediate period. Therefore, to provide continuity of rates and to avoid potential conflict with existing contracts, Saturday remains within the peak period.

The final studies credited excess revenues to summer generation capacity costs only, in contrast to the initial proposal which credited them to both seasons on a pro rata basis. This change provides more emphasis on long run incremental costs.

The California Energy Commission contends that a kilowatthour energy charge more fairly recovers capacity costs than a time-differentiated demand charge based on individual customer's periodic peak usage. Although there is some truth in the Commission's position that, for a hydro system, peaking capability depends to an extent on the duration of previous demands as well as the hourly peak level of these demands, the sustained peak demands over time contribute more directly to energy requirements. Complete reliance on only a kilowatthour charge would ignore differences in capacity costs imposed by different customers consuming the same kilowatthours but a different onpeak kilowatts.

With respect to the criticism of the time differentiation of the new resource and exchange costs on the basis of a Federal base system analysis, the alternative was to not time differentiate them. The technical mix of the exchange and new resources and the timing of their associated loads are not expected to duplicate the technology and load shape of the historic Federal Columbia River Power System. However, there is no documentation on which to base a time-differentiation analysis of these resource pools other than the analysis of the Federal base system.

Value of Reserves

BPA's firm power sales contracts with the direct-service industries provide BPA with certain rights to restrict power deliveries to these customers. These restriction

rights provide reserves to the Federal System that otherwise would have to be provided by generation resources or additional transmission facilities. In the 1974 and 1979 rate filings an availability credit was given as compensation for BPA's restriction rights on direct-service industry load. The 1979 availability credit was based on the costs of power to replace expected restrictions and was not based on any analysis of reserves. The Regional Act in Section 7(c)(3) states that BPA will determine the direct-service industries rate with consideration for the value of the reserves they provide.

BPA initially proposed a reserves credit of \$86 million, based on an incremental cost-reserve value of \$479 million in FY 1982. Both the public utility representatives and the investor-owned utility representatives argued that the \$86 million was substantially greater than it should be, while the direct-service industries advocated increasing the proposed credit. The final value of reserves study resulted in a reserve credit of \$76 million. In computing the operating and stability reserves credit in the initial proposal, incorrect ratios of average costs to incremental costs were used, and this was corrected. In addition, a further adjustment was made to reflect the LRIC relationship of capacity and energy.

The study of the value of these reserves provided through restriction rights was based on BPA's cost of alternative generation and transmission facilities for providing reserves. BPA's LRIC was used to represent the alternative cost of providing these reserves because the direct-service industry contracts are currently being renegotiated and the mutual decision of providing reserves through restriction rights has to be made again. However, while the value of the reserves is at the margin, it would be inequitable to grant the direct-service industries a reserve credit based on incremental costs because the direct-service industries and BPA's other customers are charged for power on the basis of average costs rather than marginal costs. A reserve credit based on marginal costs would be a windfall to the direct-service industries and unnecessarily burdensome for BPA's customers who are allocated the costs of the reserve credit.

Charges for Delivery Facilities

The 1974 firm power rate schedule included a separate charge based on the voltage of the customer's point of delivery. The charge was initiated to recognize that some customers take power at higher voltages and require less transformation than others. In 1979 this transformation charge was eliminated.

Customers have raised the issue again, suggesting that if BPA does not include a transformation charge in its rates, then some adjustment should be provided to customers who provide their own transformation. BPA has not reinstated a transformation charge because combining the costs for delivery facilities with other demand costs so that they are distributed among all firm power customers through the demand charge is: (1) consistent with Section 9 of the Federal Columbia River Trans-

mission System Act which requires that rate schedules be established with a view to encouraging the widest possible diversified use of electric power; (2) more equitable since it spreads the economic impact of transformation costs among all of the firm power customers rather than concentrating it on a limited number of customers who could be severely affected; and (3) consistent with the concept of postage stamp rates.

Low Density Discount

A low density discount is included in the PF-1 Priority Firm Power Rate Schedule, pursuant to Section 7(d)(1) of the Regional Act, to avoid adverse impacts on residential consumers with low system densities. The amount of the discount will depend on either the ratio of the purchaser's preceding calendar year total electrical energy requirements to the purchaser's depreciated investment in electric plant in service (excluding generating plant) on December 31 of that year, or the purchaser's ratio of residential consumers per mile of distribution line. The discount is: (1) 7 percent if such ratio is equal to or less than 15 kilowatthours per dollar of net investment, or if the number of consumers per mile of line is two or less; (2) 5 percent if such ratio is greater than 15 and equal to or less than 25 kilowatthours per dollar of net investment, or if the number of consumers per mile of line is four or less; and (3) 3 percent if such ratio is greater than 25 and equal to or less than 35 kilowatthours per dollar of net investment, or if the number of consumers per mile of line is six or less. The customer will receive the highest discount for which the utility qualifies. In addition, no customer with more than 10 residential consumers per mile of distribution line may qualify for a discount regardless of the investment ratio. This latter restriction was not included in the initial proposal and has been added as a result of comments received during the hearing process.

Other comments were received concerning eligibility requirements and criteria for calculating the discount. Some parties asserted that only preference customers should receive the discount. However, there is nothing in the Regional Act or its legislative history which would limit the discount to preference customers only. The legislative history of S. 885 indicates that the discount was proposed as an amendment by Senator Jackson and was to be offered specifically to public bodies and cooperatives. The Senate Committee on Energy and Natural Resources substituted the words "of the Administrator's customers" for the words "to public bodies and cooperatives."

Specific criteria to disqualify customers was not included, contrary to one suggestion, since BPA will review and determine eligibility of all customers for the discount at least annually. The discount criteria also will be evaluated regularly to determine whether it should be altered and whether the discounts should continue to be offered. Because of the need to review the discount periodically and because the discount is included in Section 7, which is the rate directives section of the

Regional Act, the low-density discount is considered to be a rate rather than a contract matter. Another party recommended the inclusion of an additional criterion involving the comparison of residential power costs of neighboring utilities. However, this would create a large administrative problem, and would develop information that is only peripheral to the issue.

At-Site Power

At-site power is made available under PF-1, IP-1 and MP-1 rate schedules for those customers that presently purchase power under existing contracts at the at-site rate. These customers are entitled by contract to an adjustment of \$0.257 per kilowattmonth. This adjustment is about 25 percent of the proposed postage stamp transmission component of the wholesale rate schedules and is less than the 46 percent adjustment originally developed for the Bonneville Project in 1938. The present at-site customers are adjacent to The Dalles, John Day, Hungry Horse, and Ice Harbor Projects. The conditions at these projects do not correspond to those existing at the Bonneville Project Act in 1938, that were the basis for the \$3.00 per kilowattyear adjustment. At-side delivery no longer provides any significant reduction in the transmission system required to integrate a project; therefore, BPA does not plan to extend the at-site provisions for existing customers nor enter into any new agreements for at-site power.

An adjustment has been made to recover the \$1.827 million that is given as an at-site discount. This deficiency is recovered from all users of the transmission system. This adjustment was not made in the initial proposal.

Two of the at-site customers, who had to install or acquire all the transmission facilities from the at-site point-of-delivery and pay for losses on those facilities, now recognize that the costs of these facilities exceed, or will soon exceed, the economic benefits of the at-site adjustment of the rate schedule. The at-site customer, in effect, is or will be paying a premium. While these existing customers will continue to receive no more than the credit required by the contract provisions, BPA expects to negotiate, when requested by the customer, a change of conditions to permit the customer to eliminate the at-site provisions of their contracts.

Streamflow Conditions Adjustments

A streamflow conditions adjustment was included in the PF-1, IP-1, MP-1, NR-1, RP-1, and FE-1 rate schedules in the initial wholesale rate proposal. Monthly adjustments were to be applied to all firm energy sales if actual and forecasted streamflow conditions indicated below average streamflow conditions for the remainder of the year. The major purpose of the streamflow adjustment was to provide a mechanism to alleviate the short term cash flow problem created by poor water conditions. In the past, BPA has responded to this situation by deferring payments to the Treasury for the amortization of the Federal investment in power system facilities, and if needed, for accrued interest on the Federal investment.

Any amounts deferred are subsequently included in determining BPA's future revenue requirements and need for rate adjustments.

The streamflow adjustment in the initial proposal did not require BPA to utilize any of its deferral capabilities prior to imposing a streamflow conditions adjustment. Several parties argued that this was inequitable, in that no credits would be given to the firm energy customers when water conditions and revenues were better than projected. It is still possible for BPA to tolerate significant revenue fluctuations from year to year by deferring some interest payments and planned amortization payments. In determining the appropriateness of including the streamflow adjustment in the final rate schedules, this deferral capability was taken into account.

An analysis of BPA's potential cash flow situation during the test year, assuming critical water conditions, shows that the BPA's deferral capabilities would be sufficient to cover all but the most severe cash shortfall. The results of this analysis, along with consideration of the concerns expressed by customers about the potential adverse impact of the adjustment on an individual utility's financial viability, have led to the removal of the streamflow conditions adjustment from the rate schedules. BPA will continue to analyze such a mechanism, and will more thoroughly identify and assess how it could be designed and implemented, so that it can be addressed in a future rate filing.

Equalization of Demand Charges

Comments were received that the equalization of the demand charges nullifies the COSA results and thus, ignores the cost basis of the rates. The effect of the adjustment is to reduce the industrial firm power rate and overprice the cost of the investor-owned utility exchange resources to the benefit of the direct-service industries, and to increase the priority firm rate to the detriment of public agencies and the investor-owned utility residential and farm customers. However, the adjustment permitted by Section 7(e) of the Regional Act was applied to demand charges that were relatively close in magnitude. The provision of a uniform rate for all capacity charges facilitates the administration of the rates and provides for continuity.

Adjustment of Seasonal Demand Rates

After the equalizing of the demand costs among users of the Federal base system, the summer capacity cost indicated a decrease over the current summer demand rate, while the winter capacity cost increased substantially over the current winter demand rate. For purposes of equity and to avoid encouraging additional capacity usage, the current summer capacity charge was increased by 21 percent, the rate of inflation between 1980 and 1982. Costs were removed from the winter capacity component and placed in the summer demand rate. As a result, the real cost of summer capacity when compared with the general level of inflation in the economy is the same under the 1979 rate and the 1981 rate.

Computed Demand; Overrun Charge

Most of BPA's preference customers rely on BPA for all of their power needs. A few, however, own generation facilities. Several of these allow BPA to operate their facilities or have their resources delivered directly to BPA. Others operate their own facilities. Some preference customers that do own and operate their own generation facilities are designated by the Administrator to purchase on a computed demand basis because operation of their resources can adversely impact the Federal system either through losses of power or revenue. BPA is obligated to provide the difference between the computed demand customer's load and their forecasted resource capability.

A utility that is designated to purchase on a computed demand basis has an ability and an obligation, due to the coordinated operation of resources by utilities in the Northwest, to produce an assured resource capability. The computed demand billing factors provide BPA with a means of assuring that the amount of firm power delivered to a customer does not exceed the customer's net requirements, thereby assuring BPA that the customer is using its own assured resources for its load.

When a computer demand customer receives more Federal firm power than it is entitled to, under certain conditions the excess amount is called an unauthorized increase or overrun. Several comments were received concerning this overrun charge. BPA concluded that the determination criteria for the unauthorized increase should be applied uniformly and treated as a contract matter. It is very difficult for a customer to buy on a computed demand basis. Due to variations in load, a computed demand customer, despite its best efforts, might not be able to avoid an overrun. Recognizing the difficulty of this situation, BPA has been negotiating with the computed demand customers over the last 2 1/2 years to develop a set of basic principles that will help alleviate overruns in almost all cases. In the process of negotiating current power sales contracts, BPA is contemplating including these basic principles so they would apply uniformly to all customers.

Parties also questioned the appropriateness of the level of the overrun charge, stating that the charge should be based on the cost to BPA of purchasing power to meet the overrun load. The overrun charge is not a cost-based charge. It is set at 130 mills per kilowatthour, a level high enough to discourage BPA's customers from taking an unauthorized amount of power.

Industrial Firm Rate Change on October 1, 1981, IP-1 and MP-1

Part of the resources serving the direct-service industry load have been identified as the exchange resources. The average system cost methodology that determines the cost of these resources has not yet been developed.

Therefore, the direct-service industry rate contains an "X" which represents the costs of the exchange resources.

When the exchange commences after October 1, 1981, the greater of the base rate or a rate based on the monthly exchange cost and a projected average monthly total DSI billing energy, will apply. The exchange rate is designed such that if all of the eventual parties to the exchange do not sign contracts at the same time, the rate will compensate by increasing as exchange obligations are added.

Nonfirm Energy Rate, NF-1

The new rate schedule NF-1 for nonfirm energy continues to provide flexible rates that will permit BPA to adapt to market and water supply conditions. The introduction of a flexible nonfirm rate in 1979 was controversial and elicited a great deal of comment during the public involvement process. This high level of interest has continued because an associated issue is one of equity between Regional customers and the Southwest. Recommendations for alternative nonfirm rates based on a fixed rate structure were received which would be more beneficial to the Southwest.

While the nonfirm energy rate adopted in 1979 (H-6) was based on a share-the-savings principle, the new NF-1 rate is based on the cost of resources that contribute to the availability of nonfirm energy. The NF-1 nonfirm energy rate is based on the costs of power from hydroelectric facilities, power purchases, and other resources, all of which aid in maintaining the capability of BPA to meet firm load obligations under critical water, but contribute to resources exceeding resource requirements with the occurrence of greater than critical streamflows. The rate charged under the NF-1 rate schedule is based upon: (1) the diurnally differentiated cost of hydroelectric power, which is 4.5 mills per kilowatthour during the period Monday through Saturday, 7 a.m. through 10 p.m., and 3.0 mills per kilowatthour for all other hours of the year; (2) the cost of a power purchase; (3) the cost of other resources which have been operated; or (4) a weighted average based on costs from the preceding categories. A charge of 2.0 mills per kilowatthour, the average cost of transmission is added to the kilowatthour charge for each sale of nonfirm energy. The floor rates, which are equal to the diurnally-differentiated cost of hydroelectric power plus the 2.0 mills transmission charge, are 5.0 mills per kilowatthour during offpeak hours and 6.5 mills per kilowatthour during peak hours. The ceiling rate at any time is equivalent to the cost of the most expensive power purchase or resource operated since the preceding July 31 or since the last time that all Federal Columbia River Power System reservoirs were substantially full. For contracts that refer to this rate schedule for determining the value of energy, the rate is 9.6 mills per kilowatthour. This rate is equal to the projected average NF-1 sales rate.

The costs from categories 1-3 above may be combined to derive an average charge. As an amount of energy associated with any given power purchase or resource is used to derive a charge for a sale of nonfirm energy, that purchase or resource cost will no longer be used to

determine the rate for subsequent sales of nonfirm energy. The average NF-1 sales rate of 9.6 mills per kilowatthour was changed from the 7.5 mills per kilowatthour assumed for the initial proposal on the basis of an analysis of monthly secondary energy sales and monthly operation of thermal resources and power purchases under average water conditions for FY 1982.

Due to the variability of market and water conditions, a flexible rate structure is the most appropriate for marketing BPA's nonfirm energy. A fixed rate structure that is set too low could not offer justification for operating thermal generation in order to make nonfirm energy sales. A fixed rate that is set too high would at times preclude BPA from selling available nonfirm energy thus forcing BPA to spill water. A high fixed rate would not provide the operators of Northwest thermal with an economic incentive to purchase nonfirm energy from BPA while continuing to operate their low cost thermal, and thus displace relatively higher cost oil-fired thermal. This variable rate structure will assure BPA of maximum flexibility to respond to market conditions.

Any rate based on the cost-of-service allocation process or the variable production cost of hydroelectric power would be unreasonably low. The COSA allocates only inertia costs to nonfirm service because development of generation resources is designed to meet firm loads under critical water conditions. It is also generally known that the variable production cost of hydroelectric power is less than 1 mill per kilowatthour. If the nonfirm rate were based on these costs, benefits from sales of nonfirm would be distributed inequitably because the Southwest would receive a greater portion of the benefits than the Northwest. In addition to benefitting from the Northwest integrated generation and transmission system was built at a great financial and environmental cost to the Region, the Southwest would realize a savings of 40 to 50 mills for every kilowatthour of nonfirm energy that they purchase. In addition, thermal plants are sometimes operated concurrently with sales of secondary energy to provide energy for secondary sales. A low rate based on the above costs would not cover the thermal operating costs and thus, would not justify the continued operation of the thermal plants. This would be detrimental to nonfirm energy purchasers, assuming that they would be willing to pay a rate sufficient to justify continued plant operation.

It has been suggested that BPA is required to base its rates for each general class of service on the costs of providing that service. However, a review of the cost language contained in the pertinent statutes clearly rejects this suggestion. In fact, it becomes apparent from a reading of the legislative history of the Bonneville Project Act that one of its primary objectives would not have been met if cost-based rates were required. An objective of the bill was to encourage the most widespread use of electric power in the region. A widely debated issue was whether a uniform rate, which is not based on cost, would encourage widespread use more than a zone rate, which is

lowest at the dam and increases with distance. The concern was that customers located farthest from the dams would not be able to pay actual costs using zone rates and the objective of widespread use would not be attained.

Both the language of Section 7(a)(1) of the Regional Act, the rate directives section, and the legislative history clearly indicate that Section 7(a)(1) is a restatement of the standards set forth in the Bonneville Project Act and the Transmission System Act. The Senate Report on the Regional Act notes:

"Section 7(a).—This section restates the Administrator's obligation periodically to establish and modify electric power and transmission rates. These rates *shall continue to be established* at levels to recover revenues sufficient to pay all of the Administrator's costs." S. Rep. No. 272, 96th Cong. 1st Sess. 31 (1979) (Emphasis added).

The House Interior Report similarly notes:

"Section 7(a) *continues the requirement* of existing law that BPA set its rates to recover, *in total*, the full cost (but not more than the full cost) of its financial obligations." H. Rep. No. 976, 96th Cong. 2d Sess. 52 (1980) (Emphasis added).

Thus, BPA is directed to set rates that are as low as possible consistent with sound business principles as long as they are cumulatively high enough to repay all appropriate costs. The language in the Bonneville Project Act, the Federal Columbia River Transmission System Act, and the Regional Act does not impose a cost-of-service requirement, but relates only to the revenue requirement. Additionally, rules of statutory construction support this view in that it would be improper to imply a cost-of-service standard when this requirement is not explicitly set forth in the statutes.

The contention that Section 7 of the Bonneville Project Act imposes a cost-of-service standard on BPA was rejected in *Pacific Power and Light v. Duncan*, 499 F. Supp. 672 (D. Or. 1980), appeal dismissed, No. 80-3517 (9th Cir., Feb. 13, 1981). The court noted, with reference to Section 7 of the Bonneville Project Act and BPA's PURPA 111 Order, 44 Fed. Reg. 68948 (1979), discussed *infra*:

"Despite all the references to cost, the two quoted passages do not support an inference that cost is the only basis upon which rates may be computed. The qualifying phrases 'having regard to,' 'may include,' and 'to the maximum extent practicable,' indicate that the discretion granted in 16 U.S.C. section 825s, 832e, 838g; and 43 U.S.C. section 485h(c) were not significantly altered by the requirement to consider costs in calculating rates. See *City of Santa Clara*." *Pacific supra*, 499 F. Supp. at 683.

The court continued to note that "(T)he statutory schemes, taken as a whole, invest the Secretary with such broad discretion, that with respect to the ratemaking

challenged here, judicial review is not available because there is no law to apply." *Id.* at 683.

This conclusion was further upheld in *The Montana Power Company and Idaho Power Company v. Edwards et al.*, Civil No. 80-842 PA (D. Or. May 18, 1981) (not yet reported), where the court noted:

"Although plaintiffs did not directly challenge the rate design, the impliedly did so when asserting a breach of contract. I note that the particular rates challenged here are not susceptible to judicial review because there is no law to apply. *PP&L*, at 681-683," *Id.* at 7 (citations omitted).

Rates based on considerations other than cost of service have met with administrative approval. Three other power marketing administrations, Southeastern, Southwestern, and Western Area Power Administrations, have received approval on share-the-savings rates. This rate structure has also been commonly used by investor-owned utilities, including Pacific Power and Light and Montana Power Company. It is also common utility practice to base nonfirm energy rates on the recovery of incremental costs plus up to 100 percent of fixed costs. The utilities mentioned above as well as Idaho Power Company and Puget Sound Power and Light Company use this sort of pricing for certain nonfirm energy sales.

In departing from a strict cost-of-service methodology for the NF-1 rate, BPA is conforming properly with its cost of service determination under Section 111 of the Public Utility Regulatory Policies Act of 1978 (PURPA), Pub. L. 95-917, 92 Stat. 3117 et seq. (16 U.S.C. 2601) et seq.). After adopting the cost of service standard, BPA states:

"... The rate design will always consider such an embedded cost-of-service analysis but will also consider other factors, such as marginal or long-run incremental cost principles, the purposes of conservation, efficient use of resources, and equity, and the need to meet legal considerations."

Thus, it is clear that other factors in addition to a COSA must be considered when designing rates.

Another area of concern to the parties was whether the NF-1 rate schedule complied with BPA's stated rate objectives. The first of the assertions in regard to the objectives was that a poor water year may jeopardize BPA's ability to meet its annual repayment requirement because the amount of revenue from NF-1 sales is dependent upon water conditions. Furthermore, commenters claimed that if NF-1 were based on cost of service, BPA would not be exposing itself to the same degree of revenue instability and would be able to meet the repayment obligation.

BPA's ability to repay the investment would not be jeopardized by a failure to collect a forecasted amount of revenues in any 1 year. Revenue instability results primarily from water conditions rather than from the amount of revenue forecast to be collected from its non-

firm energy sales. Regardless of the rate structure, water conditions dictate the level of nonfirm sales that is possible.

Another issue regarding the rate objectives is the contention that NF-1 customers are subsidizing firm power customers by paying the costs of purchased power and thermal generation that are incurred for firm power service. However, the NF-1 rate is equitably based on the costs of resources that contribute to the availability of nonfirm energy and implicitly recognizes the value of the generation and transmission systems of the Pacific Northwest from which nonfirm customers receive an enormous benefit.

Concern was expressed that the NF-1 rate will have a negative effect on conservation by not reflecting the true costs of firm energy. That is, it is believed that because nonfirm energy is priced above its cost and firm power rates are correspondingly lower, consumption by firm power customers is encouraged. Currently, however, there is insufficient information available with regard to the relative elasticity of demand of Northwest customers versus Southwest customers to conclude that the crediting of nonfirm energy revenue to firm capacity costs instead of other costs would result in a net total increase in consumption.

Another concern is that BPA's nonfirm energy rate will not always be the lowest cost alternative available to utilities, and thus, nonfirm energy will be spilled rather than be used to displace higher cost resources. BPA does not expect a situation to occur when water would be spilled because of the price of nonfirm energy. A great deal of flexibility has been incorporated in the NF-1 rate to respond to water and market conditions. In addition, it is BPA's policy to avoid spill situations. When necessary, BPA will sell at the floor rates, 6.5 mills per kilowatt-hour during peak hours and 5.0 mills per kilowatt-hour during all other hours, until the secondary market is saturated in order to minimize spill. The Southwest operates high-cost oil-fired thermal at an incremental cost of over 40 mills, and thus, it seems unlikely that they would not be willing to buy any available low-cost energy.

The final comments regarding the rate objectives dealt with rate continuity, ease of administration and ease of understanding. Although it is true that the proposed NF-1 rate has a different structure than the present H-6 nonfirm energy rate, it does not appear that this would disturb the California parties who have objected vigorously to the H-6 rate. In fact, some of the administrative problems of H-6 have been eased with the NF-1 rate. Voluminous records would not have to be kept nor would utilities have to supply information to BPA on a daily basis. The rate is not difficult to understand, and the administration of the rate has been well detailed during the rate development process.

Various reasons were offered as to why the transmission component of NF-1 should be reduced or deleted. The

arguments include: (1) the BPA transmission system is designed to meet peak demands of firm customers, (2) NF-1 customers enjoy no capacity rights on BPA's system, (3) there is no significant incremental transmission cost associated with surplus sales, (4) BPA is proposing to recover the same transmission costs twice, (5) the capacity/energy exchange agreements were not considered in formulating the transmission charge, and (6) intertie costs should not be allocated to nonfirm energy service.

The NF-1 transmission component explicitly recognizes the benefits of the Northwest integrated transmission system to nonfirm purchasers by charging the average cost of Federal base system energy transmission. In addition, recognition of a specific charge facilitates the process of crediting nonfirm revenues to allocated transmission costs in the rate design process.

The capacity/energy exchange agreements were not considered germane to discussions of the NF-1 rate. If capacity/energy exchange customers are given the option of not returning the energy, they pay 3 mills per kilowatt-hour under the contract agreement. BPA is not recovering transmission costs twice since the nonfirm revenues are credited to transmission costs and netted out before the transmission charges for other service classes are calculated.

The position that transmission capacity costs should not be allocated to nonfirm energy service is not inconsistent with a Federal Energy Regulatory Commission (FERC) decision, Kentucky Utilities Co., Opinion No. 116, Docket No. ER 78-147, issued April 2, 1981. FERC ruled that customers subject to curtailment of delivery or interruption by the utility should not be allocated transmission capacity costs. This FERC decision is not applicable to BPA's NF-1 service over the intertie. FERC's decision is based on the fact that no evidence was in the record to show that the customer had caused the utility to build any transmission facilities. BPA allocates intertie costs to nonfirm service because the legislative history of the intertie authorization indicated that the intertie was built, in part, to provide for nonfirm energy transmission.

Finally, the construction of a third Northwest-Southwest intertie transmission line would not be delayed unduly by the NF-1 rate structure. According to a General Accounting Office report, "Oil Savings from Greater Intertie Capacity Between the Pacific Northwest and California," the nonfirm energy rate is one of many factors that must be considered when planning a third intertie. Other major factors include the projected Northwest energy deficit, expected sales from Canada, oil prices, the amount of surplus energy available for California private utilities, and the ability to obtain Congressional approval to construct another intertie.

Variable Charge in the Wholesale Firm Capacity Rate Schedule, CF-1

BPA's current F-7 capacity rate schedule is for the sale of peaking capacity. This schedule separately identifies rates for: (a) annual capacity (delivery of capacity

throughout the year as requested by the customer) and (b) seasonal capacity (capacity delivered during 5 summertime months, principally to Pacific Southwest utilities). To encourage capacity purchasers to limit their usage of Federal generating facilities and maximize use of their own facilities, the capacity rate in the F-7 schedule includes an additional monthly charge for capacity usage in excess of 6 hours per day. The reason for this additional charge is that the Federal hydro system cannot generate as much capacity during sustained daily periods as it can for shorter periods. The CF-1 rate schedule supersedes the F-7 rate schedule.

The development of this additional charge for sustained peaking in the F-7 rate and for the initial proposal for CF-1 was based on an alternative cost principle applied to an estimate of the fuel savings realized by the customer not having to operate a combustion turbine peaking plan. This methodology was criticized by those who felt this type of sustained peaking charge was neither equitable nor cost based.

BPA's F-7 variable share-the-savings technique (halving the difference between baseload unit and peaking unit power costs) is a viable ratemaking alternative. However, in the final CF-1 rate, the charge has been related to costs incurred. In addition, the charge will be applied to capacity usage [sic] in excess of 9 hours a day rather than 6. The new cost-based variable charge is \$.029 a kilowatt-month for each additional hour of capacity in excess of 9 hours a day. The 9 hour duration was selected because it corresponds to the duration of the preference customer's peak period demand on the Federal system.

New Resources Firm Power Rate Schedule, NR-1

Section 7(f) of the Regional Act requires the establishment of this new rate. The NR-1 rate is available to the purchase of firm power for resale or for direct consumption by purchasers other than direct-service industrial customers. It can be used by investor-owned utilities to purchase power to serve their previous year's deficit plus any load growth for the current year and by public bodies or cooperatives to purchase power to serve their new large single loads. It is based only on the costs of the "new resources" pool. Federal base system resources and exchange resources are serving the loads provided under Sections 7(b) and 7(c) of the Regional Act, and are therefore not available to serve NR-1 loads.

This rate has been time differentiated in the same manner as the priority firm rate. The demand charge is also set equal to the demand charge for the PF-1 rate schedule. This adjustment represents an increase in costs classified to capacity and allocated to the rate. The energy charge was decreased to compensate for the increase in the demand charge.

Irrigation

BPA has incorporated features in its PF-1 rate schedule which tend to mitigate the effects of the rate increase irrigators. For example, applying more excess revenues

to summer capacity costs instead of prorating them between summer and winter capacity costs has resulted in a reduction in the initially proposed summer demand rate. Many comments were received advocating special rate considerations for irrigators. However, BPA rates are designed to be fair and equitable for all its customers without making special concessions for any customer, customer group, or customer class which are not defensible on cost or value basis or which are not legislatively mandated. BPA has phased out special irrigation promotion rates based on current costs of providing service to this group. The new PF-1 rate, in addition to reflecting an apportionment of costs between summer and winter demand components that is more favorable to heavy users of summer demand, provides a lower charge for power taken during the offpeak period. To the extent that irrigators or other customer groups can take advantage of and benefit from the offpeak service provision, they can take advantage of and benefit from the offpeak service provision, they can reduce their costs for a given demand level of electric service. Utilities with large irrigation loads also benefit from the low density discount.

Special Industrial Power Rate Schedule, SI-1

During the public hearings held by BPA regarding its proposals to increase power and transmission rates, the Hanna Nickel Smelting Company requested a special power rate pursuant to the requirements of Section 7(d)(2) and Section 7(c)(3) of the Regional Act. Section 7(d)(2) allows the Administrator to establish a discount rate that need not be cost-based, if any direct-service industrial customer using raw materials indigenous to the region will suffer adverse impacts of increased rates pursuant to the Regional Act, and if all power sold to such a customer may be interrupted or withdrawn to meet firm loads in the region. The Administrator determined that Hanna Nickel Smelting Company (Hanna) is eligible for a special rate under Section 7(d)(2) of the Regional Act.

Establishment of a special rate requires that Hanna be offered a special class of service. Hanna has accepted another quartile of interruptible power, and BPA is therefore able to forego a \$6.9 million purchase of 26 average megawatts of firm power which would otherwise be necessary to cover a portion of the firm energy deficit of the Federal base system. If the special Hanna rate were subsidized by other purchasers, it would only be to the extent that rates to other customers included a charge for recovery of credit given to Hanna in recognition of energy reserves no longer being provided by Hanna. To eliminate this potential subsidy, the \$6.9 million cost savings has been reduced by the amount of reserve credit associated with the value of energy reserves not provided by Hanna but paid for through other's rates. The net cost savings that will be realized by the special quality of service arrangements with Hanna is \$5.7 million.

If the quantity of power exchanged pursuant to Section 5(c) of the Regional Act and its associated costs equal the maximum amounts forecast by BPA, a cost-based

rate for Hanna might still result in serious adverse impacts for Hanna. Conversely, if the \$5.7 million net savings is credited to Hanna and the quantity and/or costs of exchange power are substantially less than BPA estimates, Hanna might actually receive a rate reduction. To preclude these potentially undesirable results, the special Hanna rate schedule has both a ceiling and a floor. If the ceiling rate applies from the initial date of the exchange, Hanna will need to obtain a significantly greater price per pound for its nickel as well as continue its efforts to cut costs and improve efficiency in order to avoid adverse impacts. The floor rate is the rate applicable to all direct-service industrial customers when there is no exchange. Contract provisions are under negotiation that will recover costs of serving Hanna that are not recovered through application of the rate, if there are such nonreimbursed costs, and if Hanna's sales price for nickel increases and/or the Hanna operation realizes profits. Independent audits and quarterly meetings to review plant operations and management will be conducted during the period of time Hanna is on a special rate.

Other Rate Design Issues

Other wholesale power rate design issues are discussed in the Staff Evaluation of Official Record and the Administrator's Record of Decision.

OTHER CONSIDERATIONS

General Rate Schedule Provisions

The General Rate Schedule Provisions which are attached to the order have remained unchanged in substance from those which accompany existing rates. A few wording changes have been made which allow the Provisions to conform to the new rate schedules. In response to comments received during the rate development process, some of the provisions will be superseded by contract terms upon completion of contracts now being negotiated.

Public Utility Regulatory Policies Act

BPA is a nonregulated utility, having more than 500 million kilowatthours in annual sales for direct use. It is therefore required by the Public Utility Regulatory Policies Act (PURPA) (Pub. L. 95-617, 92 Stat. 3117) among other things, to consider, after public notice and hearings, each of six specified ratemaking standards (Section 111(a), PURPA). Hearings were held pursuant to public notice (44 FR 35285, June 19, 1979) on July 19, 1979. The BPA Administrator issued a Determination Order concerning the rate standards on November 19, 1979 (44 FR 68948).

Effective Date of Order

It is not possible to give 30 days notice before the effective date of the rates approved on an interim basis by this order. BPA power sales contracts limit rate adjustments to fixed dates, and the next date is July 1, 1981. If this

contractually fixed date is missed, the next opportunity for adjustment will be July 1, 1982. In the interim, BPA, which is self-financed, would experience severe cash flow difficulties, in addition to falling behind in its obligation to repay the Federal Treasury for the capital cost of power projects. Rates are subject to final confirmation and approval by the Federal Energy Regulatory Commission (FERC), and the rates approved herein are subject to refund if lesser rates are ultimately approved by the FERC.

Availability of Information

Information regarding these rates including studies, hearing transcripts, and other supporting material is available for public review in the office of the Public Involvement Coordinator, Bonneville Power Administration Building, 1001 N.E. Holladay Street, Portland, Oregon 97212, and in the office of the Director of Power Marketing Coordination, 12th and Pennsylvania Avenue, N.W., Washington, D.C. 20461.

Submission to the Federal Energy Regulatory Commission

The rates herein confirmed and approved on an interim basis, together with supporting documents, will be submitted promptly to the Federal Energy Regulatory Commission for confirmation and approval on a final basis.

Environmental Impact

BPA prepared a Draft Environmental Assessment, the availability of which was announced in BPA's Federal Register Notice (46 FR 12659). BPA's Final Environmental Assessment is available for review at the locations indicated in this order and copies may be obtained by writing to the addressees indicated.

BPA has a record of decision, incorporated into the "Administrator's Record of Decision 1981 Transmission Rate Proposal and 1981 Wholesale Power Rate Proposal," designed to document the decisionmaking process related to the National Environmental Policy Act. The record is available for review at the locations indicated in this order and copies of the Record of Decision may be obtained by the public by writing to the addressees indicated.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, effective July 1, 1981, the attached wholesale power rate schedules, PF-1, IP-1, MP-1, CF-1, CE-1, NR-1, NR-1, RP-1, FE-1, and SI-1, together with the attached General Rate Schedule Provisions. These rates and provisions shall remain in effect on an interim basis through June 30, 1982, or until the FERC confirms and approves them or substitute rates on a final basis.

Issued at Washington, D.C. this 24th day of June, 1981.

Joseph J. Tribble
Assistant Secretary
Conservation and Renewable Energy

WHOLESALE POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

SCHEDULE PF-1 — PRIORITY FIRM POWER RATE

SECTION 1. *Availability:*

This schedule is available for the purchase of firm power to be used within the Pacific Northwest for resale or for direct consumption by public bodies, cooperatives, Federal agencies, and investor-owned utilities participating in the exchange under Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act). This schedule supersedes Schedule EC-8 which went into effect on an interim basis on December 20, 1979.

SECTION 2. *Rate:*

a. Demand Charge:

- (1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: \$2.80 per kilowatt of billing demand.
- (2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: \$1.44 per kilowatt of billing demand.
- (3) all other hours: No demand charge.

b. Energy Charge:

- (1) for the billing months September through March: 7.4 mills per kilowatthour of billing energy.
- (2) for the billing months April through August: 6.9 mills per kilowatthour of billing energy.

SECTION 3. *Billing Factors:*

The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

a. For any purchaser not designated to purchase under subsection 3(b), 3(c), or 3(d):

- (1) the contract demand as specified in the contract;
- (2) the measured demand for the billing month adjusted for power factor;
- (3) the measured energy for the billing month.

b. Designation of a purchaser to purchase on a computed demand basis will be according to this section unless the terms of an existing contract executed after December 5, 1980, provide otherwise. For any purchaser designated by BPA to purchase on a computed demand basis because of such purchaser's potential ability either to sell generation from its resources in such a manner as to increase BPA's obligation to deliver firm power to such purchaser in an amount in excess of BPA's obligation prior to such sale, or to redistribute the generation from its resources over time in such a manner as to cause losses of power or revenue

on the Federal System; provided, however, that when a purchaser operates two or more separate systems, only those systems designated by BPA will be covered by this subsection:

- (1) the peak computed demand for the billing month;
- (2) the average energy computed demand for the billing month;
- (3) the lesser of the peak computed demand for the billing month or 60 percent of the highest peak computed demand during the previous 11 billing months;
- (4) the measured demand for the billing month adjusted for power factor;
- (5) the measured energy for the billing month;
- (6) the contract demand as specified in an agreement between a purchaser and BPA for a specified period of time.

c. For any purchaser contractually limited to an allocation of capacity and/or energy as determined by BPA pursuant to the terms of a purchaser's power sales contract:

- (1) the allocated demand for the billing month, as specified in the contract;
- (2) the measured demand for the billing month adjusted for power factor;
- (3) the allocated energy for the billing month, as specified in the contract;
- (4) the measured energy for the billing month.

(d) For any purchaser participating in the exchange under Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act:

- (1) sixty percent of the energy associated with the utility's residential load as specified in the contract for each billing period;
- (2) the demand calculated by applying the load factor, determined as specified in the contract, to the energy in 3(d)(1) for each billing period.

SECTION 4. *Determination of Billing Demand and Billing Energy:*

a. For a purchaser governed by subsection 3(a):

- (1) the billing demand for the month shall be factor 3(a)(1) or 3(a)(2), as specified in the purchaser's power sales contract, except that at such time as BPA determines that the limitation in Section 3(c) is necessary, the billing demand for the month shall be factor 3(c)(2), provided, however, that billing demand factor 3(c)(2), before adjustment for power factor, shall not exceed factor 3(c)(1).
- (2) the billing energy for the month shall be factor 3(a)(3) except that at such time as BPA determines that the limitation in Section 3(c) is necessary, the billing energy shall be factor 3(c)(4), provided, however, that factor 3(c)(4) shall not exceed factor 3(c)(3).

b. For a purchaser governed by subsection 3(b):

- (1) the billing demand for the month shall be the largest

of factors 3(b)(3), and 3(b)(4), or 3(b)(6) if applicable. Factor 3(b)(4), before adjustment for power factor, shall not exceed the largest of factors 3(b)(1), 3(b)(2), or 3(b)(6) if applicable except that at such time as BPA determines that the limitation in Section 3(c) is necessary, the billing demand for the month shall be factor 3(c)(2), provided, however, that billing demand factor 3(c)(2), before adjustment for power factor, shall not exceed factor 3(c)(1).

(2) the billing energy for the month shall be factor 3(b)(5) except that at such time as BPA determines that the limitation in Section 3(c) is necessary, the billing energy shall be factor 3(c)(4), provided, however, that factor 3(c)(4) shall not exceed factor 3(c)(3). Factor 3(b)(5) shall not exceed factor 3(b)(2) times the number of hours during such month.

c. For purchaser governed by subsection 3(d):

- (1) the billing demand for the month shall be factor 3(d)(2).
- (2) The billing energy for the month shall be factor 3(d)(1).

SECTION 5. *Adjustments:*

a. Power Factor:

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically otherwise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

b. At-Site Power:

At-site power purchased for consumption by a purchaser shall be used within 15 miles of the powerplant specified in the power sales contract. At least 90 percent of any at-site power purchased for resale shall be used within 15 miles of the specified powerplant.

The monthly demand charge for at-site firm power will be the monthly demand charge for priority firm power reduced by \$0.257 per kilowatt of billing demand.

At-site priority firm power is made available only for those utility customers purchasing at-site firm power under existing contracts. At-site priority firm power may be purchased by such utility customers under new con-

tracts only until a date certain specified in such new contracts. If deliveries are made from an interconnection with the Federal System other than at one of such designated points, the purchaser shall pay an amount adequate to cover the annual cost of the facilities which would have been required to delivery such power to such point from either the generator bus at the generating plant, or from the adjacent point as designed by BPA. This use-of-facilities charge shall be in addition to the charge determined by the application of Section 2 of the Rate Schedule as reduced by the provisions of this subsection.

c. Low-Density Discount:

A predetermined discount will be applied each month of a calendar year to the charges for power purchased under contracts between BPA and its customers. The amount of such discount is based on the ratio of the total annual energy requirements of the purchaser's electric operations during the preceding calendar year to the purchaser's depreciated investment in electric plant in service (excluding generating plant) at the end of such year, or the purchaser's ratio of residential consumers per mile of line. This calculation of such ratio will be made using the customer's entire system. Provided that the purchaser's ratio of residential consumers per mile of line does not exceed ten, this discount shall be:

- (1) Seven percent if such ratio is less than 15 kilowatthours per dollar of net investment or if the number of consumers per mile of line is two or less.
- (2) Five percent if such ratio is equal to or greater than 15 or less than 25 kilowatthours per dollar of net investment, or if the number of consumers per mile of line is four or less.
- (3) Three percent if such ratio is equal to or greater than 25 and less than 35 kilowatthours per dollar of net investment, or if the number of consumers per mile of line is six or less.

SECTION 6. *Unauthorized Increase:*

That portion of (a) any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from BPA) that cannot be assigned to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such hour, or (b) the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month which cannot be assigned to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such month, may be considered an unauthorized increase. Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pur-

suant to (a) and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under (b).

The charge for an unauthorized increase shall be \$0.13 per kilowatthour.

SECTION 7. *General Provisions:*

Sales of power under this schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

SCHEDULE IP-1 — WHOLESALE POWER RATE FOR INDUSTRIAL FIRM POWER

SECTION 1. *Availability:*

This schedule is available for the purchase by existing direct-service industrial customers of industrial firm power and/or authorized increase on a contract demand basis and for auxiliary power requested by the purchaser and made available an auxiliary demand by BPA on an intermittent basis. This rate schedule supersedes Schedule IF-2 which went into effect on an interim basis on December 20, 1979.

SECTION 2. *Rate:*

a. Demand Charge:

- (1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: \$2.80 per kilowatt of billing demand.
- (2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: \$1.44 per kilowatt of billing demand.
- (3) all other hours: No demand charge.

b. Energy Charge:

The greater of:

- (1) for the billing months September through March: 7.4 mills per kilowatthour of billing energy; for the billing months April through August: 6.9 mills per kilowatthour of billing, or
- (2) for the billing months September through March: $(1.7 + (X/2465))$ mills per kilowatthour of billing energy; for the billing months April through August: $(1.6 + (X/2480))$ mills per kilowatthour of billing energy.

Where X = the actual month's cost in thousands of dollars incurred by the Administrator pursuant to Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act.

SECTION 3. *Billing Factors:*

The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

- a. operating demand;
- b. curtailed demand;
- c. restricted demand;
- d. measured energy.

SECTION 4. *Determination of Billing Demand and Billing Energy:*

The billing demands for industrial firm power and authorized increase, respectively, and for auxiliary power requested by the purchaser and made available by BPA as an auxiliary demand on an intermittent basis will be the lowest of the respective operating demand, curtailed demand, or restricted demand after each such demand is adjusted for power factor. The billing energy associated with each of the respective billing demands will be the measured energy distributed proportionately among the respective demands for each hour each such demand is applicable during the billing month.

SECTION 5. *Adjustments:*

a. *Value of Reserves:*

A monthly billing credit for the value of the reserves provided by purchasers of industrial firm power shall be:

- (1) \$0.33 per kilowatt of billing demand.
- (2) 2.3 mills per kilowatthour of billing energy.

The adjustment shall be applied to the same billing factors which are used to determine the billing for power purchased under this rate schedule.

b. *Power Factor:*

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the appropriate demand (operating, curtailed, or restricted) for each month by 1 percent for 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically otherwise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes or power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

c. *At-Site Power:*

At-site industrial firm power shall be used within 15 miles of the power plant.

The monthly demand charge for at-site industrial firm power will be the monthly demand charge for industrial

firm power reduced by \$0.257 per kilowatt of billing demand.

At-site industrial firm power is made available only for those industrial customers purchasing at-site industrial firm power under existing contracts. At-site industrial firm power may be purchased by such industrial customers under new contracts only until a date certain specified in such new contracts. If deliveries are made from an interconnection with the Federal System other than at one of such designated points, the purchaser shall pay an amount adequate to cover the annual cost of the facilities which would have been required to deliver such power to such point from either the generator bus at the generating plant, or from the adjacent point as designated by BPA. The use of facilities charge shall be in addition to the charge determined by application of Section 2 of the Rate Schedule as reduced by the provisions of this subsection.

SECTION 6. *Unauthorized Increase:* Any amount by which any 60-minute clock-hour integrated demand exceeds that sum of the billing demand for such hour before adjustment for power factor, plus any applicable scheduled demands which the purchaser acquires through other contracts for such hour will be assessed a charge of \$0.13 per kilowatthour.

SECTION 7. *Special Conditions — Advance of Energy:* BPA may elect to advance energy under terms and conditions of the purchaser's power sale contract.

SECTION 8. *General Provisions:* Sales of power under this schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the applicable General Rate Schedule Provisions.

SCHEDULE MP-1 — WHOLESALE POWER RATE FOR MODIFIED FIRM POWER.

SECTION 1. *Availability:* This schedule is available for the purchase by existing direct-service industrial customers of modified firm power on a contract demand basis for direct consumption by existing direct-service industrial customers until existing contracts terminate. This schedule is also available for the purchase of authorized increase power on a contract demand basis. This rate schedule supersedes Schedule MF-2 which went into effect on an interim basis on December 20, 1979.

SECTION 2. *Rate:*

a. *Demand Charge:*

(1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: \$2.80 per kilowatt of billing demand.

(2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: \$1.44 per kilowatt of billing demand.

(3) all other hours: No demand charge.

b. Energy Charge:

The greater of:

(1) For the billing months September through March: 7.4 mills per kilowatthour of billing energy; for the billing months April through August: 6.9 mills per kilowatthour of billing, or

(2) for the billing months September through March: $(1.7 + (X/2465))$ mills per kilowatthour of billing energy; for the billing months April through August: $(1.6 + (X/2480))$ mills per kilowatthour of billing energy.

Where X = the actual month's cost in thousands of dollars incurred by the Administrator pursuant to Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act.

SECTION 3. Billing Factors: The factors to be used in determining the billing for power purchases under this rate schedule are as follows:

- a. contract demand;
- b. curtailed demand;
- c. restricted demand;
- d. measured energy.

SECTION 4. Determination of Billing Demand and Billing Energy: The billing demand for modified firm power and authorized increase, respectively, will be the lowest of the respective contract demand, curtailed demand, or restricted demand after each such demand is adjusted for power factor. The billing energy associated with each of the respective billing demands will be the measured energy distributed proportionately among the respective demands for each hour each such demand is applicable during the billing month.

SECTION 5. Adjustments:

a. **Power Factor:** the adjustment for power factor, when specified in this rate schedule or power sales contract, may be made by increasing the appropriate demand (contract, curtailed, or restricted) for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically otherwise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

b. **At-Site Power:** At-site modified firm power shall be used within 15 miles of the powerplant.

The monthly demand charge for at-site modified firm power will be the monthly demand charge for modified firm power reduced by \$0.257 per kilowatt of billing demand.

At-site modified firm power will be made available under existing contracts, providing for at-site modified firm power at a Federal hydroelectric generating plant or at a point adjacent thereto, and at a voltage, all as designated by BPA. If deliveries are made from an interconnection with the Federal System other than at one of such designated points, the purchaser shall pay an amount adequate to cover the annual cost of the facilities which would have been required to deliver such power to such point from either the generator bus at the generating plant, or from the adjacent point as designated by BPA. This use of facilities charge shall be in addition to the charge determined by application of Section 2 of the Rate Schedule as reduced by the provisions of this subsection.

SECTION 6. Unauthorized Increase: Any amounts by which any 60-minute clock-hour integrated demand exceeds the sum of the billing demand for such hour (before adjustment for power factor) plus any applicable scheduled demands which the purchaser acquires through other contracts for such hour will be assessed a charge of \$0.13 per kilowatthour.

SECTION 7. General Provisions: Sales of power under this schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

SCHEDULE CF-1 — WHOLESALE FIRM CAPACITY RATE.

SECTION 1. Availability: This schedule is available for the purchase of firm capacity without energy on a contract demand basis for supply during a contract year of 12 months, or during a contract season of 5 months, June 1 through October 31. This schedule supersedes Schedule F-7 which went into effect on an interim basis on December 20, 1979.

SECTION 2. Rate:

a. **Contract Year Service:** \$25.44 per kilowatt per year of contract demand.

b. **Contract Season Service:** \$11.76 per kilowatt per season of contract demand.

c. The capacity rate specified in subsections a. and b. above shall be increased by \$0.029 per kilowatt-month of billing demand for each hour that the purchaser's monthly demand duration exceeds nine (9) hours. The purchaser's demand duration for the month

shall be determined by dividing the kilowatthours supplied under this rate schedule to a purchaser on the day of maximum kilowatthour use between the hours of 7 a.m. and 10 p.m., excluding Sundays, by the purchaser's contract demand effective for such month. If, however, BPA does not require the delivery of peaking replacement energy by the purchaser during certain periods, the additional charge above will not be made for such periods.

SECTION 3. *Billing Factors:* The billing demand will be the contract demand.

SECTION 4. *Special Provision:* Contracts for the purchase of firm capacity under this schedule will include provisions for replacement by the purchaser of energy accompanying the delivery of such capacity.

SECTION 5. *General Provisions:* Sales of power under this schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the applicable General Rate Schedule Provisions.

SCHEDULE CE-1 — EMERGENCY CAPACITY RATE.

SECTION 1. *Availability:* This schedule is available for purchase of emergency capacity requested by a purchaser when BPA determines that an emergency condition exists on the purchaser's system and it has capacity available for such purpose. This schedule supersedes Schedule F-8 which went into effect on an interim basis on December 20, 1979.

SECTION 2. *Rate:* \$0.56 per kilowatt of demand per calendar week of portion thereof. For deliveries over the Pacific Northwest-Pacific Southwest intertie, made available for the account of a purchaser at the Oregon-California or the Oregon-Nevada border, the charge will be increased by \$0.22 per kilowatt per week. Bills will be rendered monthly.

SECTION 3. *Billing Factors:* The billing demand will be the maximum amount requested by the purchaser and made available by BPA during a calendar week, provided that if BPA is unable to meet subsequent requests by a purchaser for delivery at the demand previously established during such week, such billing demand for such week shall be the lower demand which BPA is able to supply.

SECTION 4. *Special Provision:* Energy delivered with such capacity shall be returned to BPA within 7 days of the date of delivery at times and rates of delivery agreed to by the purchaser and BPA prior to delivery. BPA may agree to accept delay of return energy beyond 7 days if it so agrees prior to the delivery of capacity.

SECTION 5. *General Provisions:* Sales of power under this schedule shall be subject to the provisions of

the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

SCHEDULE NR-1 — NEW RESOURCE FIRM POWER RATE.

SECTION 1. *Availability:* This schedule is available for the purchase of firm power for resale or for direct consumption by purchasers other than direct-service industrial purchasers who purchase power under rate Schedules IP-1 or MP-1.

SECTION 2. *Rate:*

a. *Demand Charge:*

(1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: \$2.80 per kilowatt of billing demand.

(2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: \$1.44 per kilowatt of billing demand.

(3) all other hours: No demand charge.

b. *Energy Charge:*

(1) for the billing months September through March: 30.8 mills per kilowatthour of billing energy.

(2) for the billing months April through August: 24.7 mills per kilowatthour of billing energy.

SECTION 3. *Billing Factors:* The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

a. For any purchaser not designated to purchase under Section 3(b) or 3(c):

(1) the contract demand as specified in the contract;

(2) the measured demand for the billing month adjusted for power factor;

(3) the measured energy for the billing month.

b. Designation of a purchaser to purchase on a computed demand basis will be according to this section unless the terms of an existing contract executed after December 5, 1980 provide otherwise. For any purchaser designated by BPA to purchase on a computed demand basis because of such purchaser's potential ability either to sell generation from its resources in such a manner as to increase BPA's obligation to deliver firm power to such purchaser in an amount in excess of BPA's obligation prior to such sale, or to redistribute the generation from its resources over time in such a manner as to cause losses of power or revenue on the Federal System; provided, however, that when a purchaser operates two or more separate systems, only those systems designated by BPA will be covered by this subsection:

(1) the peak computed demand for the billing month;

(2) the average energy computed demand for the billing month;

(3) the lesser of the peak computed demand for the billing month or 60 percent of the highest peak computed demand during the previous 11 billing months;

(4) the measured demand for the billing month adjusted for power factor;

(5) the measured energy for the billing month;

(6) the contract demand as specified in an agreement between a purchaser and BPA for a specified period of time.

c. For any purchaser contractually limited to an allocation of capacity and/or energy as determined by BPA pursuant to the terms of a purchaser's power sales contract:

(1) the allocated demand for the billing month, as specified in the contract;

(2) the measured demand for the billing month adjusted for power factor;

(3) the allocated energy for the billing month, as specified in the contract;

(4) the measured energy for the billing month.

SECTION 4. Determination of Billing Demand and Billing Energy:

a. For a purchaser governed by subsection 3(a):

(1) the billing demand for the month shall be factor 3(a)(1) or 3(a)(2), as specified in the purchaser's power sales contract, except that at such time as BPA determines that the limitation in Section 3(c) is necessary, the billing demand for the month shall be factor 3(c)(2), provided, however, that billing demand factor 3(c)(2), before adjustment for power factor, shall not exceed factor 3(c)(1).

(2) the billing energy for the month shall be factor 3(a)(3) except that at such time as BPA determines that the limitation in Section 3(c) is necessary, the billing energy shall be factor 3(c)(4), provided, however, that factor 3(c)(4) shall not exceed factor 3(c)(3).

b. For a purchaser governed by subsection 3b:

(1) the billing demand for the month shall be the largest of factors 3(b)(3), and 3(b)(4), or 3(b)(6) if applicable. Factor 3(b)(4), before adjustment for power factor, shall not exceed the largest of factors 3(b)(1), 3(b)(2), or 3(b)(6) if applicable, except that at such time as BPA determines that the limitation in Section 3(c) is necessary, the billing demand for the month shall be factor 3(c)(2), provided, however, that billing demand factor 3(c)(2), before adjustment for power factor, shall not exceed factor 3(c)(1).

(2) the billing energy for the month shall be factor 3(b)(5) except that at such time as BPA determines that the limitation in Section 3(c) is necessary, the billing energy shall be factor 3(c)(4), provided, however, that factor 3(c)(4) shall not exceed factor 3(c)(3). Factor 3(b)(5) shall not exceed factor 3(b)(2) times the number of hours during such month.

SECTION 5. *Adjustments:*

a. *Power Factor:* The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically otherwise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

SECTION 6. *Unauthorized Increase:* That portion of (a) any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from BPA) that cannot be assigned to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such hour, or (b) the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month which cannot be assigned to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such month, may be considered an unauthorized increase. Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to (a) and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under (b).

The charge for an unauthorized increase shall be \$0.13 per kilowatthour.

SECTION 7. *General Provisions:* Sales of power under this Schedule shall be subject to the provisions of

the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

SCHEDULE NF-1 — WHOLESALE NONFIRM ENERGY RATE.

SECTION 1. Availability: This schedule is available for the purchase of nonfirm energy both inside and outside the Pacific Northwest. This schedule is also available for energy delivered for emergency use under the conditions set forth in Section 5.1 of the General Rate Schedule Provisions. This schedule is not available for the purchase of energy which BPA has a firm obligation to supply. This schedule supersedes Schedule H-6 which went into effect on an interim basis on December 20, 1979.

SECTION 2. Rate:

a. *Nonfirm Energy Rate:* The rate shall be the average cost of transmission which is 2.0 mills per kilowatthour, plus one of the following:

(1) the diurnally differentiated average cost of power from hydroelectric facilities, which is 4.5 mills per kilowatthour during the period Monday through Saturday, 7 a.m. through 10 p.m.; and 3.0 mills per kilowatthour for all other hours of the year, or

(2) the cost of a power purchase in mills per kilowatthour incurred since the preceding July 31, or the last time that all FCRPS reservoirs were substantially full, if they were not substantially full on that date, to the extent such purchase cost is unrecovered, or

(3) BPA's cost of other resources in mills per kilowatthour operated since the preceding July 31, or the last time that all FCRPS reservoirs were substantially full, if they were not substantially full on that date, to the extent such purchase cost is unrecovered, or

(4) a weighted average in mills per kilowatthour based on costs from the preceding categories.

As an amount of energy associated with any given power purchase or resource is used to derive a charge for a sale of an equivalent amount of nonfirm energy, that purchase or resource cost will no longer be used to determine the rate for subsequent sales.

b. *Contract Rate:* For contracts which refer to this schedule for determining the value of energy, the rate is 9.6 mills per kilowatthour.

SECTION 3. Delivery: BPA shall determine the availability of energy hereunder and the rate of delivery hereof.

SECTION 4. General Provisions: Sales of energy under this schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission

Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the applicable General Rate Schedule Provisions.

SCHEDULE RP-1 — RESERVE POWER RATE

SECTION 1. Availability: This schedule is available for the purchase of:

a. firm power to meet a purchaser's unanticipated load growth as provided in a purchaser's power sales contract;

b. power for which BPA determines no other rate schedule is applicable; or

c. power to serve a purchaser's firm power loads in circumstances where BPA does not have a power sales contract in form with such purchaser, and BPA determines that this rate should be applicable. This rate schedule supersedes Schedule EC-9 which went into effect on an interim basis on December 20, 1979.

SECTION 2. Rate:

a. Demand Charge:

(1) for the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: \$12.57 per kilowatt of billing demand.

(2) for the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: \$3.47 per kilowatt of billing demand.

(3) all other hours: No demand charge.

b. *Energy Charge:* 62.1 mills per kilowatthour of billing energy.

SECTION 3. Billing Factors: The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

- the contract demand as specified in the contract;
- the measured demand;
- the contract amount of energy for the month;
- the measured energy for the month.

SECTION 4. Determination of Billing Demand and Billing Energy: The billing demand and billing energy shall be determined as provided in a purchaser's power sales contract. If BPA does not have a power sales contract in force with a purchaser, the billing demand and billing energy shall be the measured demand adjusted for power factor and measured energy.

SECTION 5. Unauthorized Increase. That portion of (a) any 60-minute clock-hour integrated demand or scheduled demand (the total amount of power scheduled to the purchaser from BPA) that cannot be assigned to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such hour, or (b) the total of a purchaser's 60-minute clock-hour integrated or scheduled demands during a billing month

which cannot be assigned to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser or to a type of power which the purchaser acquires from sources other than BPA which BPA delivers during such month, may be considered an unauthorized increase. Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount which may be considered an unauthorized increase pursuant to (a) and the total of such amounts which are in fact considered unauthorized increases shall be excluded from the total of the integrated or scheduled demands for such month in determining the amount which may be considered an unauthorized increase under (b).

The charge for an unauthorized increase shall be \$0.13 per kilowatthour.

SECTION 6. *Adjustments.*

a. Power Factor: The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the measured demand for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically otherwise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

SECTION 7. *General Provisions:* Sales of power under this Schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

SCHEDULE FE-1 WHOLESALE FIRM ENERGY RATE

SECTION 1. *Availability:* This schedule is available for contract purchase of firm energy, to be delivered for the uses, in the amounts, and during the period or periods specified in such contract. This schedule supersedes Schedule J-2 which went into effect on an interim basis on December 20, 1979.

SECTION 2. *Rate:* 10.0 mills per kilowatthour of billing energy.

SECTION 3. *Billing Factors:* The contract energy is the billing factor.

SECTION 4. *Determination of Billing Energy:* The billing energy shall be determined as provided in the purchaser's power sales contract.

SECTION 5. *Delivery:* Delivery of energy under this rate schedule is assured during the contract period. However, BPA may interrupt the delivery of firm energy hereunder, in whole or in part, at any time that BPA determines that BPA is unable because of system operating conditions, including lack of generation or transmission capacity, to effect such delivery.

SECTION 6. *Adjustments:*

a. Power Factor: The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the contract energy delivered for each month by 1 percent for each 1 percent or major fraction thereof by which the average lagging power factor, or average leading power factor, at which energy is supplied during such month is less than 95 percent, such average power factor to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically otherwise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to the purchaser at a point of delivery or for a system at any time that the average power factor for all classes of power delivered to a purchaser at such point of delivery or for such system is below 75 percent lagging or 75 percent leading.

SECTION 7. *General Provisions:* Sales of power under this schedule shall be subject to the provisions of the BPA Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the General Rate Schedule Provisions.

SCHEDULE SI-1 SPECIAL INDUSTRIAL POWER RATE

SECTION 1. *Availability:* This schedule is available for the Hanna Nickel Smelting Company's purchase of a special class of industrial power and/or authorized increase on a contract demand basis and for additional power requested by the purchaser and made available as authorized increase by Bonneville on an intermittent basis. This rate schedule is made available pursuant to section 7(d)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act).

SECTION 2. *Rate:*

a. Demand Charge:

(1) For the billing months December through May, Monday through Saturday, 7 a.m. through 10 p.m.: \$2.80 per kilowatt of billing demand.

(2) For the billing months June through November, Monday through Saturday, 7 a.m. through 10 p.m.: \$1.44 per kilowatt of billing demand.

(3) All other hours: No demand charge.

b. Energy Charge:

The greater of:

(1) For the billing months September through March: 7.4 mills per kilowatthour of billing energy; for the billing months April through August: 6.9 mills per kilowatthour of billing energy; or

(2) For the billing months September through March:

((X/2465) - 4.8) mills per kilowatthour;
for the billing months April through August:
((X/2480) - 4.9) mills per kilowatthour

Where X = the actual monthly costs in thousands of dollars incurred by the Administrator pursuant to section 5(c) of the Regional Act. But the energy charge is not to exceed 10.6 mills per kilowatthour in any month, excluding any surcharges that will be made applicable pursuant to provisions of the contract to recover the costs of services if conditions affecting profitability of the purchaser's operation improves.

SECTION 3. *Billing Factors:* The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

- a. contract demand;
- b. curtailed demand;
- c. restricted demand;
- d. measured energy.

SECTION 4. *Determination of Billing Demand and Billing Energy:* The billing demands for this special class of industrial power and authorized increase, respectively, and for additional power requested by the purchaser and made available by Bonneville as authorized increase on an intermittent basis will be the lowest of the respective contract demand, curtailed demand, or restricted demand after each such demand is adjusted for power factor. The billing energy associated with each of the respective billing demands will be the measured energy distribute [sic] proportionately among the respective demands for each hour each such demand is applicable during the billing month.

SECTION 5. *Adjustments:*

a. Value of Reserves: An adjustment for the value of the reserves provided by purchasers of this special class of industrial power shall be:

- (1) \$0.33 per kilowatt of billing demand.
- (2) 2.3 mills per kilowatthour of billing energy.

The adjustment shall be applied to the same billing factors which are used to determine the billing for power purchased under this rate schedule.

b. Power Factor: The adjustment for power factor, when specified in this rate schedule or in the power sales contract, may be made by increasing the appropriate demand (operating, curtailed, or restricted) for each month by 1-percent for 1-percent or major fraction thereof by which the average lagging power factor or average leading power factor at which energy is supplied during such month is less than 95-percent, such average power factor to be computed to the nearest whole percent from the formula given in Section 9.1 of the General Rate Schedule Provisions.

The adjustment for power factor may be waived in whole or in part by BPA. Unless specifically otherwise agreed, BPA may, if necessary to maintain acceptable operating conditions on the Federal System, restrict deliveries of power to a purchaser at a point of delivery or for a system at any time that the average power factor for all classes or power delivered to a purchaser at such point of delivery or for such system is below 75-percent lagging or 75-percent leading.

SECTION 6. *Unauthorized Increase:* Any amount by which any 60-minute clock-hour integrated demand exceeds that sum of the billing demand for such hour before adjustment for power factor, plus any applicable scheduled demands which the purchaser acquires through other contracts for such hour will be assessed a charge of \$0.13 per kilowatthour.

SECTION 7. *Special Conditions - Advance of Energy:* BPA may elect to advance energy under terms and conditions of the purchaser's power sale contract.

SECTION 8. *General Provisions:* Sales of power under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended, the Regional Preference Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the applicable General Rate Schedule Provisions.

GENERAL RATE SCHEDULE PROVISIONS

SECTION 1.1. *Priority and New Resource Firm Power:* Priority and new resource firm power is electric power which BPA will make continuously available to a purchaser to meet its net firm load requirements within the Pacific Northwest except when restricted because the operation of generation or transmission facilities used by BPA to service such purchaser is suspended, interrupted, interfered with, curtailed, or restricted as the result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract. Such restriction of priority and new resource firm power shall not be made until industrial firm power has been restricted in accordance with Section 1.4 and until modified firm power has been restricted in accordance with Section 1.2.

SECTION 1.2. *Modified Firm Power:* Modified firm power is electric power which BPA will make continuously available to a purchaser on a contract demand basis subject to: (a) the restriction applicable to priority and new resource firm power, and (b) the following:

When a restriction is made necessary because the operation of generation or transmission facilities used by BPA to serve such purchaser and one or more priority and new resource firm power purchasers is suspended, interrupted, interfered with, curtailed, or restricted as a result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract BPA shall restrict such purchaser's contract demand for modified firm power to the extent necessary to prevent, if possible, or minimize restriction of any priority and new resource firm power, provided, however that:

(1) such restriction of modified firm power shall not exceed at any time 25 percent of the contract demand therefore, and

(2) the accumulation of such restrictions of modified firm power during any calendar year, expressed in kilowatthours, shall not exceed 500 times the contract demand therefor. When possible, restrictions of modified firm power will be made ratably with restrictions of industrial firm power based on the proportion that the respective contract demands bear to one another. The extent of such restrictions shall be limited for modified firm power by this subsection and for industrial firm power by the Restriction of Deliveries Section of the General Contract Provisions of the contract.

SECTION 1.3. *Firm Capacity:* Firm capacity is capacity which BPA assures will be available to a purchaser on a contract demand basis except when operation of generation or transmission facilities used by BPA to serve such purchaser is suspended, interrupted, interfered with, curtailed, or restricted as the result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract.

SECTION 1.4. *Industrial Firm Power:* Industrial firm power is electric power which BPA will make continuously available to a purchaser on a contract demand basis subject to: (a) the restriction applicable to priority and new resource firm power, and (b) the following:

(1) the restrictions given in the Restriction of Deliveries Section of the Power Sales Provisions of the contract.

(2) when a restriction is made necessary because of the operation of generation or transmission facilities used by BPA to serve such purchaser and one or more priority and new resource firm power purchasers is suspended, interrupted, interfered with, curtailed, or restricted as a result of the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Pro-

visions of the contract, BPA shall restrict such purchaser's operating demand for industrial firm power to the extent necessary to prevent, if possible, or minimize restriction of priority and new resource firm power. When possible, restrictions of industrial firm power will be made ratably with restrictions of modified firm power based on the proportion that the respective contract and operating demands bear to one another. The extent of such restrictions shall be limited for modified firm power by Section 1.2(b) of these General Rate Schedule Provisions and for industrial firm power by the Restrictions of Deliveries Section of the contract.

SECTION 1.5. *Authorized Increase:* An authorized increase is an amount of electric power specified in the contract in excess of the contract or operating demand for priority firm power, new resource firm power, modified firm power, or industrial firm power that BPA may be able to make available to the purchaser upon its request. The purchaser shall make such request in writing stating the amount of increase requested, the purpose for which it will be used, and the period for which it is needed. Such request shall be made prior to the first calendar month beginning such specified period. BPA will then determine whether such increase can be made available, but it shall retain the right to restrict the delivery of such increase if it determines at any subsequent time that such increase will no longer be available.

The purchaser may curtail an authorized increase, in whole or in part, at the end of any billing month within the period such authorized increase is to be made available.

SECTION 1.6. *Firm Energy:* Firm energy is energy which BPA assures will be available to a purchaser during the period or periods specified in the contract except during hours as may be specified in the contract [contract-Ed] and when the operation of the Government's facilities used to serve the purchaser are suspended, interrupted, interfered with, curtailed, or restricted by the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service Sections of the General Contract Provisions of the contract.

SECTION 2.1. *Contract Demand:* The contract demand shall be the number of kilowatts that the purchaser agrees to purchase and BPA agrees to make available. BPA may agree to make deliveries at a rate in excess of the contract demand at the request of the purchaser (authorized increase), but shall not be obligated to continue such excess deliveries.

SECTION 2.2. *Measured Demand:*

a. The purchaser's measured demand will be determined according to this section unless the terms of a contract executed after December 5, 1980 provide otherwise.

b. Except where deliveries are scheduled as hereinafter provided, the measured demand in kilowatts shall be the largest of the 60-minute clock-hour integrated

demands at which electric energy is delivered to a purchaser at each point of delivery during each time period specified in the applicable rate schedule during any billing period. Such largest 60-minute integrated demand shall be determined from measurements made as specified in the contract, or as determined in Section 3.2 herein. BPA, in determining the measured demand, will exclude any abnormal 60-minute integrated demands due to or resulting from (a) emergencies or breakdowns on, or maintenance of, the Federal System facilities, and (b) emergencies on the purchaser's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. For those contracts to which BPA is a party and which provide for delivery of more than one class of electric power to the purchaser at any point of delivery, the portion of each 60-minute integrated demand assigned to any class of power shall be determined as specified in the contract. The portion of the total measured demand so assigned shall constitute the measured demand for each such class of power.

If the flow of electric energy to a purchaser's system through two or more points of delivery cannot be adequately controlled because such points are interconnected within the purchaser's system, or the purchaser's system is interconnected directly or indirectly with the Federal System, the purchaser's measured demand for each class of power for such system for any billing period shall be the largest of the hourly amounts of such class of power which are scheduled for delivery to the purchaser during each time period specified in the applicable rate schedule.

SECTION 2.3 *Peak Computed Demand and Energy Computed Demand:*

The purchaser's peak computed demand and energy computed demand will be determined according to this section unless terms of a contract executed after December 5, 1980 provide otherwise.

The purchaser's peak computed demand for each billing month shall be the largest amount during such month by which the purchaser's 60-minute system demand exceeds its assured peaking capability.

The purchaser's average energy computed demand for each billing month shall be the amount during such month by which the purchaser's actual system average load exceeds its assured average energy capability.

a. General Principles:

(1) The assured peaking and average energy capability of each of the purchaser's systems shall be determined and applied separately.

(2) As used in this section, "year" shall mean the 12-month period commencing July 1.

(3) The critical period is that period, determined for the purchaser's system under adverse streamflow conditions adjusted for current water uses, assured storage

operation, and appropriate operating agreements, during which the purchaser would have the maximum requirement for peaking or energy after utilizing the firm capability of all resources available to its system in such a manner as to place the least requirement for capacity and energy on BPA.

(4) Critical water conditions are those conditions of streamflow based on historical records, adjusted for current water uses, assured storage operation, and appropriate operating agreements, for the year or years which would result in the minimum capability of the purchaser's firm resources during the critical period.

(5) Prior to the beginning of each year the purchaser shall determine the assured capability of each of the purchaser's systems in terms of peaking and average energy for each month of each year or years within the critical period. The firm capability of all resources available to the purchaser's system shall be utilized in such a manner as to place the least requirement for capacity and energy on BPA. Such assured capability shall be effective after review and approval by BPA.

(6) The purchaser's assured energy capability shall be determined by shaping its firm resources to its firm load in a manner which places a uniform requirement on BPA within each year of the critical period with such requirement increasing each year not in excess of the purchaser's annual load growth.

(7) As used herein, the capability of a firm resource shall include only that portion of the total capability of such resource which the purchaser can deliver on a firm basis to its load. The capabilities of all generating facilities which are claimed as part of the purchaser's assured capability shall be determined by test or other substantiating data acceptable to BPA. BPA may require verification of the capabilities of any or all of the purchaser's generating facilities. Such verification will not be required more often than once each year for operating plants, or more often than once each third year for thermal plants in cold standby status, if BPA determines that adequate annual preventive maintenance is performed and the plant is capable of operating at its claimed capability.

(8) In determining assured capability, the aggregate capability of the purchaser's firm resources shall be appropriately reduced to provide adequate reserves.

b. Determination of Assured Capability: The purchaser's assured peaking and energy capabilities shall be the respective sums of the capabilities of its hydroelectric generating plants based on the most critical water conditions on the purchaser's system, the capabilities of its thermal generating plants based on the adverse fuel or other conditions reasonably to be anticipated; and the firm capabilities of other resources made available under contracts prior to the beginning of the year, after deduction of adequate reserves. Assured capabilities shall be determined for each month if the purchaser has seasonal

storage. The capabilities of the purchaser's firm resources shall be determined as follows:

(1) *Hydroelectric Generating Facilities:* The capability of each of the purchaser's hydroelectric generating plants shall be determined in terms of both peaking and average energy using critical water conditions. The average energy capability shall be that capability which would be available under the storage operation necessary to produce the claimed peaking capability.

Seasonal storage shall mean storage sufficient to regulate all the purchaser's hydroelectric resources in such a manner that when combined with the purchaser's thermal generating facilities, if any, and with firm capacity and energy available to the purchaser under contracts, a uniform energy computed demand for a period of one (1) month or more would result.

A purchaser having seasonal storage shall, within 10 days after the end of each month in the critical period, notify BPA in writing of the assured energy capability to be applied tentatively to the preceding month; such notice shall also specify the purchaser's best estimate of its average system energy load for such month. If such notice is not submitted, or is submitted later than 10 days after the end of the month to which it applies, subject to the limitations stated herein, the assured energy capability determined for such month prior to the beginning of the year shall be applied to such month and may not be changed thereafter.

If notice has been submitted pursuant to the preceding paragraph, the purchaser shall, within 30 days after the end of the month, submit final specification of the assured energy capability to be applied to the preceding month; provided that the assured energy capability so specified shall not differ from the amount shown in the original notice by more than the amount by which the purchaser's actual average system energy load for such month differs from the estimate of that load shown in the original notice. If the assured energy capability for such month differs from that determined prior to the beginning of the year for such month, the purchaser, if required by BPA, shall demonstrate by a suitable regulation study based on critical water conditions that such change could actually be accomplished, and that the remaining balance of its total critical period assured energy capability could be developed without adversely affecting the firm capability of other purchaser's resources. The algebraic sum of all such changes in the purchaser's assured energy capability shall be zero at the end of the critical period or year, whichever is earlier. Appropriate adjustments in the assured peaking capability shall be made if required by any change in reservoir operation indicated by such revisions in the monthly distribution of critical period energy capability.

(2) *Thermal Generating Facilities:* The capability of each of the purchaser's thermal generating plants shall be determined in terms of both peaking and average energy. Such capabilities shall be based on the adverse

fuel or other conditions reasonably to be anticipated. The effect of limitations on fuel supply due to war or other extraordinary situations will be evaluated at the time of occurrence.

(3) *Other Sources of Power:* The assured capability of other resources available to the purchaser on a firm basis under contracts shall be determined prior to each year in terms of both peaking and average energy.

c. *Determination of Computed Demand:* The purchaser's computed demand for each billing month shall be the greater of:

(1) the largest amount during such month by which the purchaser's actual 60-minute system demand, excluding any loads otherwise provided for in the contract, exceeds its assured peaking capability for such month, or period within such month, or

(2) The largest amount for such month, or period within such month, by which the purchaser's actual system average energy load, excluding the average energy loads otherwise provided for in the contract, exceeds its assured average energy capability.

The use of computed demands as one of the alternatives in determining billing demand is intended to assure that each purchaser who purchases power from BPA to supplement its own firm resources will purchase amounts of power substantially equivalent to the additional capacity and energy which the purchaser would otherwise have to provide on the basis of normal and prudent operations, viz, sufficient capacity and energy to carry the load through the most critical water or other conditions reasonably to be anticipated, with an adequate reserve.

Since the computed demand depends on the relationship of capability of resources to system requirements, the computed demand for any month cannot be determined until after the end of the month. As each purchaser must estimate its own load, and is in the best position to follow its development from day to day, it will be the purchaser's responsibility to request scheduling of priority and new resource firm power, including any increase over previously established demands, on the basis estimated by the purchaser to result in the most advantageous purchase of the power to be billed at the end of the month.

SECTION 2.4. *Restricted Demand:* A restricted demand shall be the number of kilowatts of priority firm power, new resource firm power, modified firm power, industrial firm power, or authorized increase of any of the preceding classes of power which results when BPA has restricted delivery of such power for one (1) clock-hour or more. Such restrictions by BPA are made pursuant to the power sales contract for industrial firm power and pursuant to Section 1.1 and 1.2 of the General Rate Schedule Provisions for priority and new resource firm power and modified firm power, respectively. Such restricted demand shall be determined by BPA after the

purchaser has made its determination to accept such restriction or to curtail its contract demand for the month in accordance with Section 2.5 of the General Rate Schedule Provisions.

SECTION 2.5. *Curtailed Demand:* A curtailed demand shall be the number of kilowatts of priority firm power, new resource firm power, modified firm power, industrial firm power, or authorized increase of any of the preceding classes of power which results from the purchaser's request for such power in amounts less than the contract demand therefor. Each purchaser of industrial firm power or modified firm power may curtail its demand in accordance with the contract. Each purchaser of an authorized increase in excess of priority firm power, new resource firm power, modified firm power, or industrial firm power may curtail its demand in accordance with Section 1.5 of the General Rate Schedule Provisions.

SECTION 3.1. *Billing:* Unless otherwise provided in the contract, power made available to a purchaser at more than one point of delivery shall be billed separately under the applicable rate schedule or schedules. The contract may provide for combined billing under specified conditions and terms when (a) delivery at more than one point is beneficial to BPA, or (b) the flow of power at the several points of delivery is reasonably beyond the control of the purchaser.

If deliveries at more than one point of delivery are billed on a combined basis for the convenience of the customer, a charge will be made for the diversity between the measured demands at the several points of delivery. The charge for the diversity shall be determined in a uniform manner among purchasers and shall be specified in the contract.

SECTION 3.2. *Determination of Estimated Billing Data:* If the purchased amounts of capacity, energy, or the 60-minute integrated demands for energy must be estimated from data other than metered or scheduled quantities, BPA and the purchaser will agree on billing data to be used in preparing the bill. If the parties cannot agree on estimated billing quantities, a determination binding on both parties shall be made in accordance with the arbitration provisions of the contract.

SECTION 4.1 *Application of Rates during Initial Operation Period:* For an initial operating period, not in excess of 3 months, beginning with the commencement of operation of a new industrial plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree (a) to bill for service to such new, additional, or reactivated plant facilities on the basis of the measured demand for each day, adjusted for power factor, or (b) if such facilities are served by a distributor purchasing power therefor from BPA to bill for that portion of such distributor's load which results from service to such facilities on the basis of the measured demand for each day, adjusted for power factor. Any rate schedule provisions regarding

contract demand, billing demand, and minimum monthly charge which are inconsistent with this Section shall be inoperative during such initial operating period.

The initial operating period and the special billing provisions may, on approval by Bonneville, be extended beyond the initial 3 month period for such additional time as is justified by the developmental character of the operations.

SECTION 5.1. *Energy Supplies for Emergency Use:* A purchaser taking priority and/or new resource firm power shall pay in accordance with Wholesale Nonfirm Energy Rate Schedule NF-1 and Emergency Capacity Schedule CE-1 for any electric energy which has been supplied; (a) for use during an emergency on the purchaser's system, or (b) following an emergency to replace energy secured from sources other than BPA during such emergency, except that mutual emergency assistance may be provided and settled under exchange agreements.

SECTION 6.1. *Billing Month:* Meters will normally be read and bills computed at intervals of 1 month. A month is defined as the interval between meter-reading dates which normally will be approximately 30 days. If service is for less or more than the normal billing month, the monthly charges stated in the applicable rate schedule will be appropriately adjusted. Winter and summer periods identified in the rate schedules will begin and end with the beginning and ending of the purchaser's billing month having meter-reading dates closest to the periods so identified.

SECTION 7.1 *Payment of Bills:* Bills for power shall be rendered monthly and shall be payable at BPA's headquarters. Failure to receive a bill shall not release the purchaser from liability for payment. Demand and energy billings under each rate schedule application shall be rounded to whole dollar amounts, by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

If BPA is unable to render the purchaser a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill, if so issued, shall have the validity of and be subject to the same repayment provisions as shall a final bill.

Bills not paid in full on or before the close of business of the 20th day after the date of the bill shall bear an additional charge which shall be the greater of one-fourth percent (0.25%) of the amount unpaid or \$50. Thereafter a charge on one-twentieth percent (0.05%) of the sum of the initial amount remaining unpaid and the additional charge herein described shall be added on each succeeding day until the amount due is paid in full. The provisions of this paragraph shall not apply to bills rendered under contracts with other agencies of the United States.

Remittances received by mail will be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the 20th day after the date of the bill. If the 20th day after the date of the bill is a Sunday or other nonbusiness day of the purchaser, the next following business day shall be the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the 20th day must bear a postal department cancellation in order to avoid assessment of such further charges.

BPA may, whenever a power bill or a portion thereof remains unpaid subsequent to the 20th day after the date of the bill, and after giving 30 days advance notice in writing, cancel the contract for service to the purchaser, but such cancellation shall not affect the purchaser's liability for any charges accrued prior thereto.

SECTION 8.1 *Approval of Rates:* Schedules of rates and charges, or modifications thereof, for electric power sold by BPA shall become effective on a final basis after confirmation and approval by the Federal Energy Regulatory Commission. Pending the establishment of procedures by the Commission to approve rates on a final basis, the entity or entities having been designated by the Secretary of Energy prior to December 5, 1980, shall have authority to confirm and approve schedules of rates and charges on an interim basis.

SECTION 9.1. *Average Power Factor:* The formula for determining average power factor is as follows:

Average Power Factor =

$$\frac{\text{Kilowatthours}}{\sqrt{(\text{Kilowatthours})^2 + (\text{Reactive Kilovoltamperehours})^2}}$$

The data used in the above formula shall be obtained from meters which are ratcheted to prevent reverse registration.

When deliveries to a purchaser at any point of delivery include more than one class of power or are under more than one rate schedule, and it is impracticable to separately meter the kilowatthours and reactive kilovoltamperehours for each class, the average power factor of the total deliveries for the month will be used, where applicable, as the power factor for each of the separate classes of power and rate schedules.

SECTION 10.1. *Temporary Curtailment of Contract Demand:* The reduction of charges for power curtailed pursuant to the purchaser's contract and Section 1.5 and 2.5 hereof shall be applied in a uniform manner.

SECTION 11.1. *General Provisions:* The Wholesale Rate Schedules and General Rate Schedule Provisions of the BPA Power Administration effective July 1, 1981, supersede in their entirety BPA's Wholesale Power Rate Schedule Provisions effective December 20, 1979.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR CONSERVATION
AND RENEWABLE ENERGY

In the Matter of:

Bonneville Power Administration —) Rate Order
Systemwide Transmission Rates) No. BPA-5

**ORDER CONFIRMING, APPROVING, AND
PLACING INCREASED TRANSMISSION
RATES INTO EFFECT ON AN INTERIM BASIS
(June 24, 1981)**

The functions of the Secretary of the Interior and the Federal Power Commission under the Bonneville Project Act, 16 U.S.C. 832, the Federal Columbia River Transmission System Act, 16 U.S.C. 838, and other statutes relating to the Bonneville Power Administration (BPA) were transferred to and vested in the Secretary of Energy pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act, Public Law 95-91. The Secretary of Energy, pursuant to section 7(i)(6) of the Pacific Northwest Electric Power Planning and Conservation Act (Public Law 96-501) is authorized to approve BPA power and transmission rates on an interim basis during a 1-year period, pending establishment of procedures by the Federal Energy Regulatory Commission (FERC) for approving rates on an interim basis, in the event the FERC determines such procedures are necessary. Upon advice from the FERC that such procedures are necessary and will not be established prior to October 1, 1981, the Secretary of Energy delegated to the Assistant Secretary for Conservation and Renewable Energy in the June 19, 1981 Supplement to Delegation Order No. 0204-33, the authority to confirm, approve, and place into effect such rates on an interim basis. This rate order is issued pursuant to that delegation to the Assistant Secretary.

BACKGROUND

Existing Rates

Existing transmission rates were conditionally approved on an interim basis on June 10, 1977 by the Federal Power Commission. That conditional confirmation and approval was extended on July 6, 1978 by the Economic Regulatory Administration for a 1-year period, and further extended on May 12, 1979, by the Assistant Secretary for Resource Applications for an indefinite period. The rates superseded by the new rate schedules were remanded without prejudice by a Federal Energy Regulatory Commission Order issued December 1, 1980, Docket No. E-9563. The record for those rates is being further developed and will be separately submitted to the Commission.

The three rate schedules now in effect on an interim basis are:

FPT-1, for the firm transmission of electric power and energy using unspecified portions of the Federal transmission system; UFT-1, for the firm transmission of electric power and energy using specified portions of the Federal transmission system; and ET-1, for the incidental transmission of electric power and energy using excess capacity of the Federal transmission system.

Need for Rate Increase

Pursuant to the Bonneville Project Act (Pub. L. 75-329 as amended), the Federal Columbia River Transmission System Act (Pub. L. 93-454), the Reclamation Project Act of 1939 (Pub. L. 85-611 as amended), the Flood Control Act of 1944 (Pub. L. 78-534), Section 2 of the Grand Coulee Third Powerhouse Authorization (Pub. L. 89-448 as amended) and the Pacific Northwest Electric Power Planning and Conservation Act (Pub. L. 96-501), the BPA Administrator conducted a revised power repayment study to determine the revenue necessary to recover the cost of producing, purchasing, and transmitting the electric power BPA markets, to repay investments as required by statute, and to recover other costs associated with the Pacific Northwest Electric Power Planning and Conservation Act (Regional Act). The results of the study showed the need for a 78.5 percent increase in total revenues over the repayment study period, excluding revenues required to cover the cost of acquiring investor-owned utility exchange resources. Total revenues needed will be met by the increase in transmission rates approved by this order and the increase in wholesale rates approved by my Rate Order No. BPA-4.

Because the Repayment Study is concerned only with the adequacy of total revenues, BPA prepared a Cost-of-Service Analysis to separately identify the costs of providing transmission services. The most recent version of this study shows that revenues under the three transmission rate schedules need to be increased an average of 43 percent in order to recover the allocated costs.

The existing transmission rate schedules would produce revenues of approximately \$30,154,000 in fiscal year 1982. The new transmission rates would produce approximately \$43,000,000 during that year.

Public Notice and Comment

In response to the Cost-of-Service Analysis which showed that revenues from current transmission rates were inadequate to meet the allocated costs to transmission, BPA published in the May 25, 1979, *Federal Register* (44 FR 30405) a "Notice of Intent to Revise Transmission Rates." In December 1980, BPA met with various customer groups to elicit their comments and suggestions for an initial transmission rate proposal.

On December 5, 1980, the Regional Act became law. Sections 5, 7, and 9 of that Act altered BPA's rate development procedures, the costing methodology, and in some cases, rate design. BPA published proposed trans-

mission rates in the February 17, 1981 *Federal Register* (46 FR 12659) based on the procedures identified in the Regional Act. The initial transmission rate proposal was supported by an environmental determination, a power repayment study, a cost-of-service analysis, a long run incremental cost analysis, a time-differentiated pricing analysis, and a transmission rate design study.

On March 2, 1981, the formal hearing process required by the Regional Act began with a BPA presentation of the initial rate proposals. The BPA staff was cross-examined and 37 parties presented their testimony. Rebuttal testimony was taken, and oral arguments and briefs were presented. The hearings closed for wholesale power rates on May 4, 1981, and for transmission rates on May 27, 1981. The hearing process for transmission rates was extended through May 27, 1981, to allow inclusion of the transcript of meetings for consideration of contract matters offered for the first time in this rate filing. The BPA staff prepared an evaluation of the record which was made available to the parties on May 27, 1981, for their review. In addition, BPA staff prepared an addendum to the staff evaluation of the record covering transmission issues that were received too late to be included in the initial evaluation document. On the basis of the record, the BPA Administrator developed his final proposed transmission rate schedules and General Transmission Rate Schedule Provisions. These schedules and provisions are given interim approval by this order.

In addition to studies conducted by BPA, the Administrator issued a Record of Decision documenting the process by which both the wholesale power and transmission rates were developed. This includes the significant public comments received, BPA's responses to such comments, and the rationale for the Administrator's decisions.

I am unable to give 30 days prior notice before the effective date of these transmission rates and BPA's wholesale power rates because the record in this proceeding did not close until May 27, 1981 and the rate design process required that the studies indicated herein be reconducted. In order to assure recovery of revenues on a timely basis I am making these transmission rates effective on July 1, 1981, concurrent with the wholesale power rates which must, by contract, be adjusted July 1, 1981.

Studies Conducted by BPA

The new transmission rates are based on studies conducted two or more times by BPA to reflect the most recent cost data available, and to make changes as a result of public comment. In addition to those studies itemized and discussed in Order No. BPA-4 which support both the wholesale power and transmission rates, a February 5, 1981 Environmental Determination for BPA's 1981 transmission rate filing was prepared and two transmission rate design studies were conducted, an initial study in February 1981 and the final studies

in June 1981. The new transmission rate schedules are based on results of the final studies that appropriately reflect public comments, criticisms, and suggested alternatives.

Transmission Rate Design Study

The Transmission Rate Design Study formulates a system of transmission rate schedules that recovers the revenue requirement allocated to the firm transmission component in the Cost-of-Service Analysis and provides rates for nonfirm and specific facility uses. A variety of factors are important in the design of BPA's transmission rate schedules. Primary among these factors in BPA's legislative requirement to equitably allocate the recovery of costs of the transmission system between Federal and non-Federal power utilizing the system and the obligations of its current wheeling contracts. Additional factors that are considered in the design of the transmission rate schedules are: competition from non-Federal transmission facilities, treatment of non-Federal costs and use, cost studies (Long Run Incremental Cost Analysis and Time-Differentiated Pricing Analysis in addition to the Cost-of-Service Analysis), equitable sharing of the benefits and risks of the Federal Columbia River Transmission System, efficient resource utilization, rate integrity, rate continuity, and ease of administration of the rate schedules.

While continuing BPA's present transmission rate structure would serve the purpose of rate continuity and integrity and would be consistent with contractual obligations, many of the other rate objectives would not be accomplished. However, a uniform, postage stamp rate schedule with a broader, more flexible service would also meet BPA's statutory requirements and would better serve the other rate objectives. As a result of these circumstances, optional transmission rate schedules have been developed. For convenience, these schedules have been referred to as Set A and Set B.

Set A schedules update BPA's current transmission rates and as such reflect historic decisions embodied in the present contractual arrangements. In the initial proposal, Set B included two rate schedules which, in the final study, were combined. Set B now refers only to the IR-1 schedule. It reflects many of the other rate design objectives and provides customers with a broader, more flexible service at a uniform rate. The IR-1 schedule is designed as an interim, 1-year set of rates and contracts to offer more flexible service while BPA develops new transmission policy. In February 1981, BPA published a Notice of Intent to develop a new transmission policy that will be responsive to customers' changing needs and consistent with management of the transmission system in the public interest.

The Set A schedules consist of three rate schedules: Formula Power Transmission (FPT-2) for wheeling of firm power over unspecified facilities, Energy Transmission (ET-2) for wheeling of nonfirm power, and Use-of-Facilities Transmission (UFT-2) for wheeling of

firm power over specific and limited facilities. Set B, the Integration of Resources (IR-1) schedule, is for the integration of resources into the network and for firm intertie service. The IR-1 schedule is intended to be an option to FPT-2. Either one of these schedules may be used with ET-2 and UFT-2 schedules to provide a customer with all the transmission services required.

A transmission customer electing to retain the service, rate form, and loss determination provisions of existing contracts would utilize Set A rates.

For those parties electing the alternative transmission service and the standardized loss determination methodology offered by BPA under interim contracts for the period prior to the development of the transmission policy, the IR-1 rate will be applicable along with the UFT-2 and ET-2 rate schedules for use-of-facilities arrangements and nonfirm energy transmission. To provide transmission customers with an opportunity to receive service under the IR-1 schedule without permanently terminating existing contracts and to provide a period for development of a long-range transmission policy, Set B service and rates will be available for a 1-year trial period after which time a customer can choose to return to Set A service and rates or opt for the service offered to all customers under the new transmission policy formulated during this next year.

DISCUSSION

Because of the dual nature of the hearings, covering both wholesale and transmission rate development, comments and criticisms were received which were pertinent to both rate filings. Those issues which are addressed in Rate Order No. BPA-4 (wholesale power rates) are not duplicated here. Only those major issues unique to the transmission rate filing are discussed here. These issues fall into three broad categories: cost issues, rate design issues, and service issues.

Classification of Transmission System Costs

BPA's initial proposal classified all transmission costs to capacity. However, BPA staff noted that it might be appropriate to classify some transmission costs to energy and invited comment on methods to do so. Several comments suggested that some costs should be classified to energy and two methodologies were proposed. The difficulty in using either of the proposed methodologies resides in the manner in which transmission costs are incurred. Increments of transmission investment are made for a variety of reasons, many of which are not related solely to either capacity or energy transactions during the test year. While transmission investment may be incurred to provide for peakloads in the test year or beyond, or to reduce energy losses, other reasons for an investment could be to improve reliability of the transmission system, to improve the stability of generation, to mitigate environmental concerns, and to reduce noise. Another difficulty that must be addressed is that trans-

mission system uses frequently change over time and differ markedly from the purposes for which the facilities were originally planned. BPA determined that neither of the two proposed methodologies recognize the full range of cost causation factors. BPA classified transmission costs to capacity but used a 12 CP allocation factor which recognizes an energy component through an averaging of the 12 coincidental peaks. BPA plans to further review classification of transmission costs to capacity and energy in future rate filings.

Level of Costs

Because BPA incurs costs to provide reliable transmission service to all of its customers as opposed to piecemeal transmission components for individual customers, it may be that the rates resulting from a system costing approach could be higher than the alternative transmission costs available to a particular customer. One utility suggested that it could construct its own transmission system at a cost lower than the charges resulting from BPA's IR-1 rate. BPA will continue to encourage its customers to submit evidence that its alternative transmission costs are less than the charges under BPA's rates so that any potential for the construction of duplicate transmission facilities can be averted. To date BPA has received no evidence that this problem exists. The IR-1 rate therefore contains no special provisions related to the potential problem.

Distance Factor in Rate Design

BPA received comments both for and against recognizing the distance between a customer's resource and its load as a relevant factor in developing transmission rates. Some argued that distance is an important cost causation factor and should be recognized in order to prevent construction of duplicative short distance facilities. Others argued that distance is not an identifiable cost factor in an integrated transmission system because of diversity (in the use of resources to meet load) and displacement (a customer's resource may not be physically meeting that customer's load but is instead meeting another customer's load). BPA finds the relationship between distance and cost to be an extremely tenuous one and therefore did not apply it in the costing process. Consistent with this finding, the IR-1 rate also excludes distance as a separate rate factor. However, since the existing FPT contracts contain distance as a factor, the FPT-2 rate for these contracts continues using distance as one of the rate factors. All customers with firm wheeling contracts have the option of selecting rate schedule FPT-2 with its distance component or rate schedule IR-1 which does not have one.

Service Related Issues

BPA received several suggestions for modifying the transmission services it provides. Notable among these were: (1) the one way restrictions in FPT rates should be eliminated, (2) BPA should offer the transmission customers the same services as those customers would

have obtained if the customer had constructed the transmission system, (3) the availability of the schedules should be sufficiently broad to allow a customer to choose which rate schedules to apply to specific transactions, and (4) losses should be treated as a rate matter.

The so-called one-way restriction refers to application of a transmission rate to transmission service from a specific receipt point to a designated delivery point. Consequently, the rates would be applied to service between those same points in the opposite direction even though the transmission required would be a net amount. This restriction does not apply to the IR-1 rate but continues to be a feature of the FPT-2 rate schedule.

The new rates do allow the customers the choice of limited service under the Set A rates or broad service under the IR-1 rate. Should a customer choose the IR-1 rate, then it will be entitled to engage in transactions with any other customer who also chooses that rate at no additional charge. This option is believed to be similar to the type of service available to a sole owner of a transmission system. The new rates also respond in part to the request for the availability of multiple rates. The customers can choose between FPT and IR schedules but is not allowed to mix the two. Allowing a mixture of the two appears to be contrary to the principles involved in developing either alone. For example, BPA rationalizes that if distance is important (as it is under the FPT-2 rates) then it should be important for all of a customer's transactions and not just those transactions which are "short" and result in a lower customer charge. Finally, the treatment of losses offered under the IR-1 rate is also responsive to the customers' comments. Further mitigation of the concerns about losses may occur as BPA develops its transmission policy. At this time, however, BPA is constrained to treating losses for customers remaining on the Set A rates in the manner specified in the contracts.

General Transmission Rate Schedule Provisions

The General Transmission Rate Schedule Provisions for the Set A rate schedules are largely unchanged from existing provisions and continue the philosophy inherent in existing contracts. In addition, General Transmission Rate Schedule Provisions are included for the alternate Set B rate schedules. The latter provisions reflect the broad range of services available under the IR-1 rate schedule.

Other Transmission Rate Issues

Other transmission rate issues are discussed in the Staff Evaluation of the Official Record and the Administrator's Record of Decision.

Availability of Information

Information regarding these rates including studies, hearing transcripts, and other supporting material is available for public review in the office of the Public Involvement Coordination, Bonneville Power Administration Building, 1002 N.E. Holladay Street, Portland, Oregon 97212, and in the office of the Director of Power

Marketing Coordination, 12th and Pennsylvania Avenue, N.W., Washington, D.C. 20461.

Submission to the Federal Energy Regulatory Commission

The rates herein confirmed and approved on an interim basis, together with supporting documents, will be submitted promptly to the Federal Energy Regulatory Commission for confirmation and approval on a final basis.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, effective July 1, 1981, the attached transmission rate schedules, FPT-2, UFT-2, ET-2, and IR-1, together with the attached General Transmission Rate Schedule Provisions (Set A) and General Transmission Rate Schedule Provisions (Set B). These rates and provisions shall remain in effect on an interim basis through June 30, 1982, or until the FERC confirms and approves them or substitute rates on a final basis. Pursuant to Delegation Order 0204-33, as amended, if lower rates are ultimately approved by FERC, the revenues collected in excess of such finally approved rates shall be refunded with interest to the extent determined by the Commission.

Issued at Washington, D.C. this 24th day of June, 1981.

Joseph J. Tribble
Assistant Secretary
Conservation and Renewable Energy

TRANSMISSION RATE SCHEDULES

Set A Rates:

SCHEDULE FPT-2 — FORMULA POWER TRANSMISSION.

SECTION 1. Availability: This schedule supersedes FPT-1 and is available for existing and new Agreements which provide for firm transmission of electric power and energy using the Integrated Network Segment, and/or the PNW-PSW Intertie Segment. This schedule is for full-year and partial-year service and for either continuous service or intermittent service so long as a firm availability of service is required.

SECTION 2. Rate:

A. Full-Year Service: The monthly charge per kilowatt of Transmission Demand shall be one-twelfth of the sum of the Main Grid Charge, the Secondary System Charge and Intertie Charge, as applicable and as specified in the Agreement.

1. **Main Grid Charge:** The Main Grid Charge shall

be the sum of one or more of the following factors as specified in the Agreement:

a. Main Grid Distance Factor — The amount computed by multiplying the Main Grid Distance by \$0.0200 per mile;

b. Main Grid Integration Terminal Factor — \$0.16;

c. Main Grid Miscellaneous Facilities Factor — \$0.89;

d. Main Grid Terminal Factor — \$0.16; and

e. Main Grid Delivery Terminal Factor — \$0.25.

2. **Secondary System Charge.** The Secondary System Charge shall be the sum of one or more of the following factors associated with deliveries at 115 kV as specified in the Agreement:

a. Secondary Transformation Factor — \$1.41;

b. Secondary System Integration Terminal Factor — \$0.41;

c. Secondary System Distance Factor — The amount determined by multiplying the Secondary System Distance by \$0.1029 per mile;

d. Secondary System Intermediate Terminal Factor — \$0.41;

e. Secondary System Delivery Terminal Factor — \$0.48.

3. **Intertie Charge** — for use of Intertie facilities — \$3.56.

B. Partial-Year Service: The monthly charge per kilowatt of capacity shall be as specified in Section 2.A. for all months of the year except:

1. For unplanned firm service, such as emergency station service when a generating unit is down, the yearly charge shall be equal to one monthly charge as defined in Section 2.A. so long as the use during each year does not exceed 730 hours. If the use during each year exceeds 730 hours, the yearly charge shall be as specified in Section 2.A.

2. For agreements whose term in 5 years or less and which specify service for fewer than 12 months per year, the charge shall be:

a. during months for which service is specified, the monthly charge defined in Section 2.A., and

b. during other months, the monthly charge defined in Section 2.A. multiplied by 0.2.

SECTION 3. Determination of Transmission Demand: Unless otherwise stated in the agreement, the factor to be used in determining the kilowatts of Transmission Demand is the largest of:

A. the Transmission Demand specified in the Agreement;

B. the highest Measured or Scheduled Demand for the month; or

C. the Ratchet Demand.

SECTION 4. *General Provisions:* Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric Power Planning and Conservation Act; and the 1981 General Transmission Rate Schedule Provisions. The meaning of terms used in this rate schedule shall be as defined in the Agreement or any of the above Acts or Provisions which are attached to the Agreement.

SCHEDULE ET-2 — ENERGY TRANSMISSION.

SECTION 1. *Availability:* This schedule supersedes ET-1 and is available for nonfirm transmission of non-Federal electric energy using excess capacity of the FCRTS. This rate is not available for the transmission of energy that is used to meet firm obligations on a planning basis, nor for energy which cannot be interrupted.

SECTION 2. *Rates:* The charge for nonfirm transmission of non-Federal nonfirm electric energy shall be based on the following rates.

	<u>Mills/kWh</u>
1. Delivery Over Integrated Network	0.97
2. Delivery Over the PNW-PSW Intertie	1.46
3. Delivery Over PNW-PSW Intertie including use of PNW Transmission System	2.43

SECTION 3. *General Provisions:* Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric Power Planning and Conservation Act; and the 1981 General Transmission Rate Schedule Provisions. The Meaning of terms used in this rate schedule shall be as defined in the Agreement or any of the above Acts or Provisions which are attached to the Agreement.

SCHEDULE UFT-2 — USE—OF—FACILITIES TRANSMISSION.

SECTION 1. *Availability:* This schedule is available for the firm transmission of electric power and energy over specified FCRTS facilities installed or operated primarily for the benefit or convenience of a limited number of customers. This schedule is not appropriate for new agreements for service over the Integrated Network Segment, or the PNW-PSW Intertie Segment.

SECTION 2. *Rates:* The monthly charge per kilowatt of Transmission Demand specified in the Agreement shall be one-twelfth of the Annual Cost per kilowatt of Capacity of the specified facilities. Such Annual Cost shall be determined in accordance with Section 3.

SECTION 3. *Determination of Transmission Rate:*

A. From time to time, but not more often than once in each Contract Year, BPA shall determine the following data for the facilities which have been constructed or otherwise acquired by BPA and are used to transmit electric power and energy thereunder:

1. Capital cost of each such facility as specified in the most recently published plant investment records of BPA which are issued in support of the Federal Columbia River Power System financial statement.

2. Annual Interest and Amortization Ratios for each such facility using the most recent system average cost factors developed from actual Interest and Amortization costs for specific categories of FCRTS facilities and from data included in the financial statement.

3. Operation, maintenance, administrative and general, and general plant costs of such facilities using the most recent system average costs for specific categories of FCRTS facilities.

4. The yearly noncoincidental peak demands of all users of such facilities.

B. The monthly charge per kilowatt of Transmission Demand shall be one-twelfth of the sum of the Annual Cost per kilowatt of each of the FCRTS facilities used. The Annual Cost per kilowatt of each facility constructed or otherwise acquired by BPA shall be determined in accordance with the following formula:

$$\frac{(I \times R) + B}{D}$$

Where B = Operation, maintenance, administrative and general, and general plant cost of such facility as determined in A.3.

I = Capital cost of such facility as determined in A.1.

R = Annual Interest and Amortization Ratio for such facility as determined in A.2.

D = The sum of the yearly noncoincidental demands on the facility as determined in A.4.

The Annual Cost per kilowatt of facilities listed in the Agreement which are owned by another entity, and used by BPA for making deliveries to the Transferee, shall be determined from the costs specified in the Agreement between BPA and such other entity.

SECTION 4. *Determination of Transmission Demand:* Unless otherwise stated in the Agreement, the factor to be used in determining the kilowatts of Transmission Demand shall be the largest of:

A. the Transmission Demand specified in the Agreement;

B. the highest Measured or Scheduled Demand for the month, the Measured Demand being adjusted for power factor; or

C. the Ratchet Demand.

SECTION 5. General Provisions: Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric Power Planning and Conservation Act; and the 1981 General Transmission Rate Schedule Provisions. The meaning of terms used in this rate schedule shall be as defined in the Agreement or any of the above Acts or Provisions which are attached to the Agreement.

General Transmission Rate Schedule Provisions:

1. *Interpretation.* The provisions in the Agreement to which these General Transmission Rate Schedule Provisions (GTRSP) are attached as an exhibit shall be part of these GTRSP for the purpose of determining the meaning of any provision contained herein. If a provision in such Agreement is in conflict with a provision contained herein, the former provision shall prevail.

2. *Bonneville Service Area.* The Bonneville Power Administration (BPA) shall operate and maintain the Federal Columbia River Transmission System (FCRTS) within the Pacific Northwest and shall construct such improvements, betterments, system additions and replacements within the Pacific Northwest as it determines are appropriate and required to:

- a. integrate and transmit "electric power" from existing or additional Federal or non-Federal generating units;
- b. provide service to the BPA wholesale power and wheeling customers;
- c. provide interregional transmission facilities; or
- d. maintain the electrical stability and electric reliability of the Federal Columbia River Power System.

3. *Availability of Transmission Service.* Any capacity in the FCRTS which BPA determines to be in excess of the capacity required to transmit Federal power will be made available to all utilities on a fair and nondiscriminatory basis by the application of schedules identified in the Schedule of Transmission Rates, dated 1981 or as subsequently revised.

4. *Billing Details.*

a. The Transmission Billing Determinant is the electric power quantified by the method specified in the Transmission Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

b. Bills for transmission service will be computed and rendered monthly, generally on a calendar-month basis.

c. Bills not paid in full on or before the close of business of the twentieth day after the date of the bill shall bear an additional charge which is the greater of

one-fourth percent (0.25%) of the amount unpaid or \$50. Thereafter, a charge of one-twentieth percent (0.05%) of the sum of the initial amount remaining unpaid and the additional charge herein described shall be added on each succeeding day until the amount due is paid in full. The provisions of this paragraph do not apply to bills rendered under contracts with other agencies of the United States.

Remittances received by mail shall be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the payment was mailed on or before the twentieth day after the date of the bill. If the twentieth day after the date of the bill is a Sunday or other nonbusiness day of the customer, the following day is the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the twentieth day shall bear a postal department cancellation in order to avoid assessment of such further charges.

BPA may, whenever a transmission bill or a portion thereof remains unpaid subsequent to the twentieth day after the date of the bill, and after giving 30 days' advance notice in writing, cancel the Agreement, but such cancellation shall not affect the customer's liability for any charges accrued prior thereto.

If BPA is unable to render the customer a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill, if so issued, shall have the validity of, and shall be subject to, the same payment provisions as a final bill. Failure to receive a bill shall not release the customer from liability for payment. Billings under each rate schedule application are rounded to whole dollar amounts, by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

d. For an initial operating period, not to exceed 3 months, beginning with the commencement of operation of a new generating plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree to modify the measured or scheduled demand established for that period, or make other adjustments which are determined to be appropriate.

e. The transmission customer shall furnish BPA necessary information for making any computation required for the purposes of determining the proper charges for the use of the FCRTS and shall cooperate with BPA in exchanging such additional information as may be reasonably useful for respective operations.

5. *Definitions.* Capitalized terms that are used in the Transmission Rate Schedules shall be as defined

below, or, if not so defined, as defined in the Agreement.

a. *Agreement*: The transmission agreement to which this exhibit is attached.

b. *Connection Point*: Refers collectively to the following:

(1) *Point of Integration (POI)*: Connection points where a non-Federal project is integrated with the FCRTS.

(2) *Point of Delivery (POD)*: Connection points where power is delivered to a customer from the FCRTS. The power may be Federal or non-Federal.

(3) *Point of Exchange (POE)*: Connection points listed in an Exchange Agreement. Power may be delivered or received at POE without special accounting.

c. *Electric Power* (or simply *Power* if no confusion would result without a modifier of mechanical, chemical, or electrical): Electric peaking capacity (kW), or electric energy (kWh), or both.

d. *Firm Transmission Service*: Firm availability of transmission service for any power scheduled or otherwise made available, limited only by the amount and time period specified in the Agreement. Firm transmission service is supplied for all types of power, such as firm, nonfirm, exchange, interruptible, or other.

e. *Interest and Amortization Ratio*: The annual interest and amortization costs of the Federal Columbia River Transmission System, or any applicable portion thereof, divided by the investment in such system or portion thereof.

f. *Main Grid*: That portion of the FCRTS with facilities rated 230 kV and higher, exclusive of the Intertie.

g. *Main Grid Delivery Terminal*: 230 kV Terminal Facilities associated with a Point of Delivery.

h. *Main Grid Distance*: The distance in airline miles on the Main Grid between the Point of Integration and the Point of Delivery, multiplied by 1.15.

i. *Main Grid Integration Terminal*: The Main Grid Terminal Facilities located at the Point of Integration.

j. *Main Grid Miscellaneous Facilities*: Switching, transformation and other backup facilities of the Main Grid required to integrate the Main Grid.

k. *Main Grid Terminal*: Terminal facilities on the Main Grid adjacent to the Secondary System.

l. *NonFirm Transmission Service*: Service for which BPA will accept power only when it determines excess capacity is available. Once BPA accepts power for transmission service, the service provided is the same for firm and nonfirm transmission service.

m. *Ratchet Demand*: The maximum past or present demand established during the previous 11 billing

months based on the highest scheduled demand during that time.

n. *Secondary System*: That portion of the FCRTS facilities with operating voltage of 115 kV or 69 kV, exclusive of Main Grid facilities, Intertie facilities, and lower voltage (less than 69 kV) FCRTS facilities which may be used on a use-of-facility basis.

o. *Secondary System Delivery Terminal*: A Point of Delivery from a Main Grid substation at 115 kV or 69 kV, or a terminal located at a Point of Delivery from the Secondary System.

p. *Secondary System Distance*: The number of circuit miles of Secondary System transmission lines between the Main Grid and the Point of Delivery or the lower voltage FCRTS facilities which may be used on a use-of-facility basis, as specified in the Agreement.

q. *Secondary System Integration Terminal*: The first Terminal Facility in the Secondary System.

r. *Secondary System Intermediate Terminal*: The final Terminal Facilities in the Secondary System.

s. *Secondary Transformation*: Transformation from Main Grid to Secondary System facilities.

Set B Rates:

SCHEDULE IR-1 — INTEGRATION OF RESOURCES.

SECTION 1. *Availability*. This schedule is available for the integration of non-Federal resources by the Integrated Network Segment of FCRTS and for firm transmission over the Pacific Northwest-Pacific Southwest Intertie. This schedule is available only to utilities who agree to convert all firm transmission agreements using the Integrated Network and Intertie Segments (except Columbia Storage Power Exchange and other agreements as mutually agreed) to interim agreements consistent with this rate schedule.

SECTION 2. *Rate*.

a. *Network Service*: The monthly charge shall be the sum of:

(1) \$0.1749 per kilowatt of Network Billing Demand, and

(2) \$0.00056 per kilowatthour of Network Billing Energy.

b. *Intertie Service*: The monthly charge for firm service over the PNW — PSW Intertie shall be the charges in 2(a) plus the sum of:

(1) \$0.3024 per kilowatt of Intertie Billing Demand, and

(2) \$0.00081 per kilowatthour of Intertie Billing Energy.

SECTION 3. *Determination of Billing Demand and Billing Energy*. The Billing Demand for the Network and

for the Intertie shall be as specified in the Agreement. The Network Billing Energy shall be all power scheduled to the Integrated Network from resources specified in the Agreement. The Intertie Billing Energy shall be all firm energy scheduled over the Intertie pursuant to the terms of the Agreement.

SECTION 4. General Provisions. This Rate Schedule shall continue in effect until July 1, 1982. This schedule shall not be used for long-term agreements. The Services provided under this schedule shall be subject to the provisions of the Bonneville Project Act, as amended; the Federal Columbia River Transmission System Act; the Pacific Northwest Electric Power Planning and Conservation Act; the General Wheeling Provisions, Form 3, and the General Transmission Rate Schedule Provisions. The meaning of terms used in this rate schedule shall be as defined in the Agreement or any of the above Acts or Provisions which are attached to the Agreement.

GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS (GTRSP)

FOR SET B TRANSMISSION SCHEDULES

1. *General:* This GTRSP applies to any and all Set B Rate Schedules. The provisions in the Interim IR Agreement to which this GTRSP is attached as an exhibit shall be part of this GTRSP for the purpose of determining the meaning of any provision contained herein. If a provision in such Agreement is in conflict with a provision contained herein, the provisions in the Agreement shall prevail.

2. *Availability:* Any capacity, in the Federal Columbia River Transmission System (FCRTS) which BPA determines to be in excess of the capacity required to transmit Federal power and previous firm obligations of non-Federal power, will be made available to all utilities on a fair and nondiscriminatory basis. Charges for the use of the FCRTS will be as identified in the Transmission Schedules.

3. Billing Details:

a. Bills for transmission service will be computed and rendered monthly, generally on a calendar-month basis.

b. Bills not paid in full on or before the close of business of the twentieth day after the date of the bill shall bear an additional charge which is the greater of one-fourth (0.25) percent of the amount unpaid or \$50. Thereafter, a charge of one-twentieth (0.05) percent of sum of the initial amount remaining unpaid and the additional charge herein described shall be added on each succeeding day until the amount due is paid in full. The provisions of this paragraph do not apply to bills rendered under contracts with other agencies of the United States.

Remittances received by mail shall be accepted without assessment of the charges referred to in the preceding paragraph provided the postmark indicates the

payment was mailed on or before the twentieth day after the date of the bill. If the twentieth day after the date of the bill is a Sunday or other nonbusiness day of the customer, the following day is the last day on which payment may be made to avoid such further charges. Payment made by metered mail and received subsequent to the twentieth day shall bear a postal department cancellation in order to avoid assessment of further charges.

BPA may, whenever a transmission bill or a portion thereof remains unpaid subsequent to the twentieth day after the date of the bill, and after giving 30 days' advance notice in writing, cancel the Agreement, but such cancellation shall not affect the customer's liability for any charges accrued prior thereto.

If BPA is unable to render the customer a timely monthly bill which includes a full disclosure of all billing factors, it may elect to render an estimated bill for that month to be followed at a subsequent billing date by a final bill. Such estimated bill, if so issued, shall have the validity of, and shall be subject to, the same payment provisions as a final bill. Failure to receive a bill shall not release the customer from liability for payment. Billings under each rate schedule application are rounded to whole dollar amounts, by elimination of any amount of less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

c. For an initial operating period, not to exceed 3 months, beginning with the commencement of operation of a new generating plant, a major addition to an existing plant, or reactivation of an existing plant or important part thereof, BPA may agree to modify the measured or scheduled demand established for that period, or make other adjustments which are determined to be appropriate.

d. The transmission customer shall furnish BPA necessary information for making any computation required for the purposes of determining the proper charges for the use of the FCRTS and shall cooperate with BPA in exchanging such additional information as may be reasonably useful for respective operations.

4. *Definitions:* Capitalized terms (other than titles, proper nouns, and other words which normally have the first letter capitalized) and expressions in "quotes" that are used in Transmission Schedules, GTRSP, or in the Agreement shall be as defined below, or if not so defined, as defined in the Agreement. If a definition in the Agreement is in conflict with a definition below, the definition in the Agreement shall prevail.

a. *Agreement:* The interim, 1 year Integration of Resources Agreement to which this GTRSP is attached as an exhibit.

b. *"approved point of connection:"* Those points of connection which BPA and the customer using SET B Transmission Schedule agree are reasonable points of connection.

c. BPA: The Bonneville Power Administration, its Administrator, or his staff to which he has delegated certain responsibilities.

d. Contract Year — means the period of time commencing at 12:01 a.m., on July 1, 1981, and ending at 12:00 p.m., on June 30, 1982.

e. FCRTS: The Federal Columbia River Transmission System which includes those transmission facilities located within the Pacific Northwest that BPA has constructed or acquired for marketing Federal power or for transmitting non-Federal power.

f. "firm non-Federal resource:" The resource that a non-Federal utility identifies in the Pacific Northwest Utilities Conference committee's West Group Forecast and is required to meet that utilities' firm loads and capacity reserves. Those resources that provide a surplus in a particular year may also be considered a "firm non-Federal resource" on a case by case basis if other non-Federal customers in the same class have deficits which can be met by the surplus.

g. FPT Schedule: The Formula Power Transmission Rate Schedule identifies 14 different rates for various transmission facilities.

h. GTRSP: The General Transmission Rate Schedule Provisions supplements various Rate Schedules.

i. Intertie Service: That transmission service provided by the PNW-PSW Intertie which consists of 2-500kV and 1-800kV transmission lines between the Columbia River and the southern Oregon border.

j. Network Service: That transmission service provided by the Network Segment of the FCRTS.

k. Pacific Northwest: (1) the region consisting of the States of Oregon, Washington, and Idaho, the State of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming within the Columbia River drainage basin; and (2) any contiguous areas, not in excess of seventy-five airline miles from the area referred to above, which are a part of the service area of a rural electric cooperative customer that is served by the Administrator and has a distribution system from which it serves both within and without such region.

l. Power: electric peaking capacity, or electric energy or both.

m. Transmission Schedules: Any of the various transmission rate schedules identified in Set B Transmission Schedules.

n. UFT Schedule: The Use of Facilities Rate Schedule which identifies the methodology to use for developing a rate for proportional use of specific facilities.

5. *General Provisions:* This GTRSP for Set B Transmission Schedules has a limited purpose for a limited

time, probably 1 year, during which a new transmission policy will be developed. Consequently, this GTRSP is expected to be superseded within 1 year.

DEPARTMENT OF ENERGY ASSISTANT SECRETARY FOR CONSERVATION AND RENEWABLE ENERGY

In the Matter of:

Western Area Power Administration—)
Fryingpan-Arkansas Project) Rate Order
Capacity Without Energy) No. WAPA-9

ORDER CONFIRMING, APPROVING, AND PLACING A POWER RATE INTO EFFECT ON AN INTERIM BASIS (July 10, 1981)

Pursuant to section 302(a) of the Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*, the power marketing functions of the Secretary of the Interior under the Reclamation Act of 1902, 43 U.S.C. 372, *et seq.*, as amended and supplemented by subsequent enactments, particularly by section 9(c) of the Reclamation Project Act of 1939, 43 U.S.C. 485h(c), for the Bureau of Reclamation were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 FR 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, Western Area Power Administration (Western), and to confirm, approve, and place in effect such rates on an interim basis, and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. Due to a Department of Energy organizational realignment, Delegation Order No. 0204-33 was amended, effective March 19, 1981, to transfer the authority of the Assistant Secretary for Resource Applications to the Assistant Secretary for Conservation and Renewable Energy. This rate order is issued pursuant to the delegation to the Assistant Secretary.

BACKGROUND

The Fryingpan-Arkansas Project

The Fryingpan-Arkansas Project (Fry-Ark) is a trans-mountain water diversion development in the central and southeastern parts of Colorado. The project diverts water from the Fryingpan and Roaring Fork Rivers on the west slope of the Continental Divide to the east slope of the Continental Divide. The Arkansas River then conveys project water downstream for irrigation, and municipal and industrial uses.

The principal power feature of the project is the Mt. Elbert Pumped-Storage Powerplant, located on the east slope of the Continental Divide. The Mt. Elbert Powerplant will have two pump/generator units. Each unit is

rated 100 MW during the generating cycle and 130 MW during the pumping cycle. The first unit is scheduled to begin operating in July 1981. The second unit is scheduled to begin operating in August 1983.

Western's Fry-Ark transmission system consists of one 230-kV line which extends from the Mt. Elbert Switchyard to Public Service Company of Colorado's (Public Service) Malta Substation. Western has contracted with Public Service for wheeling service for Fry-Ark generation from Malta Substation over Public Service's transmission system to points of interconnection between Western and Public Service, and for wheeling Fry-Ark pumping energy from the points of interconnection to Malta Substation. The initial Fry-Ark points of interconnection are Malta Substation, Midway Substation, Weld Substation, Rifle Substation, Beaver Creek Substation, Erie Substation, Summit Substation, and Poncha Junction. The Fry-Ark customer shall bear the transmission costs and losses incurred by the United States for transmission of generation and pumping energy between Malta Substation and the points of interconnection. This cost under the United States-Public Service contract is 1 mill/kWh and 5-percent losses in each direction.

Additional transmission beyond Fry-Ark points of interconnection shall require arrangements to be made by the customer. However, Western has initiated discussions with other non-Federal owners of transmission in the market area in an attempt to expand the transmission service that the United States contracts for on behalf of Fry-Ark customers. The costs and losses for such transmission will have to be borne by the customer.

Public Notice and Comment

In accordance with the rate adjustment procedures published at 10 CFR Part 903 (45 FR 86975, December 31, 1980, as amended by 46 FR 6864 (January 22, 1981) and 46 FR 25426 (May 7, 1981)), Western published notice of the proposed minor rate in the Federal Register (46 FR 19809) on March 31, 1981. A public information forum was held on April 8, 1981. A public comment forum was held on April 29, 1981. The consultation and comment period ended on May 15, 1981.

The rate for Fry-Ark capacity without energy is defined as a minor rate adjustment under the aforementioned procedures because it is for a new service for a new power system which will have annual sales of less than 100 million kilowatthours.

DISCUSSION

Service Availability

The power service which will be marketed from the Fry-Ark is capacity without energy. It will be available for sale east of the Continental Divide in Colorado and Wyoming, west of the 101st meridian in Nebraska, and in Kansas west of the eastern boundaries of those counties

intersected by the 100th meridian. The customers will be required to provide the necessary pumping energy.

Rate

The rate for Fry-Ark capacity without energy is \$3.11/kW/mo based on the contract rate of delivery.

Repayment Accounting

The rate has been designed, in accordance with mandates of the authorizing acts, to return to the United States the project costs allocated to power within 50 years of completion of each power unit and the irrigation costs assigned to power for repayment within 50 years of completion of the irrigation facilities. It is based on data contained in the July 31, 1980, Fry-Ark power repayment study.

Allocation of Joint Costs

A recent Department of the Interior internal audit suggested a change in the allocation of joint costs that would increase the total capital costs allocated to power from \$148,744,000 to \$179,251,000. However, there is an unresolved question as to whether the possible change derives from a change in cost allocation or project evaluation standards, and therefore is subject to prior approval of Congress pursuant to the Department of Energy Organization Act. A decision on reallocation of joint costs will not be available in time for use in initial contracts. If the change is allowed, the power rate may have to be increased by a subsequent rate adjustment.

Public Comments

Two comments were received concerning transmission arrangements for Fry-Ark capacity. The thrust of the comments was:

A. The United States should negotiate on behalf of Fry-Ark customers for transmission arrangements in addition to those established in the United States—Public Service wheeling contract.

B. The costs of such present and future Fry-Ark transmission arrangements should be incorporated into the Fry-Ark power rate.

The Mt. Elbert-Malta transmission line is interconnected with Public Service's transmission system. Existing transmission arrangements were negotiated at a time when most of the interest in Fry-Ark power was expressed by entities interconnected with Public Service's transmission system. Additional transmission arrangements are needed to adequately serve the expanded group of entities now requesting Fry-Ark capacity. As stated previously, Western has initiated discussion with other non-Federal owners of transmission in the market area in an attempt to expand the transmission service that the United States contracts for on behalf of Fry-Ark customers.

Western recognizes that there may be merit to the suggestion that the cost of such present and future Fry-Ark

transmission arrangements be incorporated into project costs and reflected in the Fry-Ark power rate. When and if additional transmission arrangements have been agreed upon, Western will consider incorporating all transmission charges set by United States Fry-Ark transmission service contracts into the Fry-Ark power rate.

National Environmental Policy Act

Western has determined that this ratesetting action does not constitute a major Federal action significantly affecting the quality of the human environment. Therefore, no environmental assessment or environmental impact statement has been prepared.

Availability of Information

Information regarding this rate adjustment proceeding is available for public review in the Office of the Administrator, Western Area Power Administration, 1536 Cole Boulevard, Golden Colorado 80401, and in the Office of the Director of Power Marketing Coordination, 12th and Pennsylvania Avenue, NW., Washington, D.C. 20461.

Submission to the Federal Energy Regulatory Commission

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

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, effective July 11, 1981, Rate Schedule FA-1. This rate shall remain in effect on an interim basis for a period of 12 months unless such period is extended, or until the FERC confirms and approves this or a substitute rate on a final basis, whichever occurs first.

Issued in Washington, D.C., July 10, 1981.

Joseph J. Tribble
Assistant Secretary
Conservation and Renewable Energy

Rate Schedule FA-1

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

Fryingpan-Arkansas Project

SCHEDULE OF RATES FOR CAPACITY WITHOUT ENERGY

Effective:

July 11, 1981.

Available:

In the area served by power from the Fryingpan-Arkansas Project.

Applicable:

To wholesale power customers for capacity without energy.

Character and Condition of Service:

Alternating current, 60 hertz 3-phase, delivered and metered at the voltage and points established by contract.

Monthly Rate:

\$3.11 per kilowatt of contract rate of delivery.

Adjustments:

Customers will be required to bear transmission costs and losses of 1 mill/kWh and 5-percent losses in each direction for wheeling of energy to and from the Malta Substation over the transmission system of Public Service Company of Colorado.

UNITED STATES OF AMERICA DEPARTMENT OF ENERGY ASSISTANT SECRETARY FOR CONSERVATION AND RENEWABLE ENERGY

In the Matter of:

Southeastern Power Administration —) Rate Order
Kerr-Philpott Projects' Power Rates) No. SEPA-11

ORDER CONFIRMING AND APPROVING POWER RATES ON AN INTERIM BASIS (SEPTEMBER 14, 1981)

Pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act, Public Law 95-91, the functions of the Secretary of the Interior and the Federal Power Commission under Section 5 of the Flood Control Act of 1944, 16 U.S.C. 825s, relating to the Southeastern Power Administration (SEPA) were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 F.R. 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve, and place in effect such rates on an interim basis and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. Due to a Department of Energy organizational realignment, Delegation Order No. 0204-33 was amended, effective March 19, 1981, to transfer the authority of the Assistant Secretary for Resource Applications to the Assistant Secretary for Conservation and Renewable Energy. This rate order is issued pursuant to the delegation to the Assistant Secretary for Conservation and Renewable Energy.

BACKGROUND

Power from the Kerr-Philpott Projects is presently sold under Wholesale Power Rate Schedules KP-1-B, KP-2-B, and JHK-1-B. These rates were confirmed and approved by the Federal Power Commission on February 18, 1976, for a period ending June 30, 1980, and extended by the Federal Energy

Regulatory Commission on January 29, 1981, for a period ending September 30, 1981. SEPA is in the process of developing a new written power marketing policy for the Kerr-Philpott Projects and has requested that I approve a one-year extension of two of the rate schedules and an adjustment to the other rate schedule to allow time to finalize the policy, renegotiate expiring contracts and permit applicable rates appropriate to such revised policy to be developed, confirmed and approved, and placed in effect.

Public Notice and Comment

SEPA prepared a Power Repayment Study in June 1981 for the Kerr-Philpott Projects which showed that an increase in existing rates was not necessary to produce revenues sufficient to pay all power costs during the system repayment period as required to meet cost recovery criteria. Based on this Repayment Study, it was proposed to extend two of the rate schedules until September 30, 1982. An additional wheeling charge, applicable only to the customers who purchase power under JHK-1-B rate schedule, was not included in the Repayment Study. However, a revised rate schedule was drafted to pass through the increased wheeling costs to affected customers.

Opportunities for public review and comments on the extension of rates and proposed increased power rate were announced by Notice published in the Federal Register on June 5, 1981, 46 F.R. 108, and all customers were notified by mail. A Public Comment and Public Information forum was held in Raleigh, North Carolina on July 9, 1981, where an opportunity for oral presentation of views was afforded. Written comments were invited by the Notice through August 14, 1981. A transcript of the Public Comment Forum was made.

DISCUSSION

System Repayment

SEPA's System Power Repayment Study of June 1981 is basically an update of its System Repayment Study dated March 1975, upon which existing rates are predicated. The March 1975 repayment study included estimated costs through September 30, 1980, which were less than the costs actually experienced. Estimated future costs are slightly higher than the costs estimated in 1975; however, the Repayment Study continues to show that the revenues at present rate levels are adequate to recover all costs required by the repayment criteria.

There is one item of cost, however, which was not in-

cluded in the Repayment Study and that is an increased annual wheeling charge of \$200,000 required by Carolina Power & Light Company. An adjusted rate schedule appropriately responds to this added cost.

Rate Design

Because the rates are expected to be in effect for only a one-year period, the KP-1-B, and KP-2-B rates are being extended and the added wheeling charge from CP&L is being passed directly through to the effected customers. The adjusted Rate Schedule JHK-1-C is identical to the present rate schedule except a "wheeling charge" is added. The monthly wheeling charge to cover the additional cost is \$0.56 per kilowatt of contract demand.

Environmental Impact

SEPA has reviewed the possible environmental impacts of the rate adjustment under consideration and has concluded with Departmental concurrence that, because the increased rates would not significantly affect the quality of the human environment within the meaning of the National Environmental Policy Act of 1969, the proposed action is not a major Federal action for which preparation of an Environmental Impact Statement is required.

Availability of Information

Information regarding these rates including studies, public comment forum transcript, and other supporting material are available for public review in the offices of Southeastern Power Administration, Samuel Elbert Building, Elberton, Georgia 30635, and in the Office of the Director of Power Marketing Coordination, 12th and Pennsylvania Avenue, N. W., Washington, D.C. 20461.

Submission to the Federal Energy Regulatory Commission

The rate herein confirmed and approved on an interim basis, together with supporting documents, will be submitted promptly to the Federal Energy Regulatory Commission for confirmation and approval on a final basis for a period ending no later than September 30, 1982.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, effective October 1, 1981, attached Wholesale Power Rate Schedules KP-1-B, KP-2-B and JHK-1-C. The rate schedules shall remain in effect on an interim basis through September 30, 1982, unless such period is extended or until the FERC confirms and approves them or substitute rate schedules on a final basis.

Issued at Washington, D.C., this 14th day of September, 1981.

Joseph J. Tribble
Assistant Secretary
Conservation and Renewable Energy

UNITED STATES
DEPARTMENT OF THE INTERIOR
SOUTHEASTERN POWER ADMINISTRATION
**WHOLESALE FIRM POWER RATE SCHEDULE
KP-1-B**

Availability:

This rate schedule shall be available to public bodies and cooperatives (any one of which is hereinafter called the Customer) within a 150 mile radius of the John H. Kerr Project, purchasing power generated at the John H. Kerr and Philpott Projects in wholesale quantities under appropriate contracts and served through the facilities of the Virginia Electric and Power Company (hereinafter called the Company).

Applicability:

This rate schedule shall be applicable to firm power and accompanying energy generated at the John H. Kerr and Philpott Projects and to deficiency energy purchased by the Government from the Company, purchased in wholesale quantities under appropriate contracts for a specified number of kilowatts of capacity and shall be applied to each customer's system consisting of one or more delivery points.

Character of Service:

The electric capacity and energy supplied hereunder will be 3-phase alternating current at a nominal frequency of 60 Hertz. The voltage of delivery will be maintained within the limits established by the state regulatory commission.

Monthly Rate:

The monthly rate for capacity and energy sold under this rate schedule shall be:

Demand Charge:

\$1.25 per kilowatt of contract demand.

Energy Charge:

5.00 mills per kilowatt-hour.

Contract Demand:

The contract demand is the amount of capacity in kilowatts stated in the contract which the Government is obligated to supply and the Customer is entitled to receive.

Energy to be Furnished by the Government:

The Government will sell to the Customer and the Customer will purchase from the Government energy each billing month equivalent to a total amount annually of 5,000 kilowatt-hours per kilowatt of contract demand prorated on an equal daily amount throughout the year. The Customer's contract demand and accompanying energy will be allocated proportionately to its individual delivery points served from the Company's system.

Billing Month:

The billing month for power sold under this schedule shall end at 12:00 midnight on the last day of each calendar month.

Conditions of Service:

The Purchaser shall at its own expense provide, install and maintain on its side of each delivery point the equipment necessary to protect and control its own system. In so doing, the installation, adjustment, and setting of all such control and protective equipment at or near the point of delivery shall be coordinated with that which is installed by and at the expense of the Company on its side of the delivery point.

Service Interruption:

When energy delivery to the Customer's system is reduced or interrupted for 1 hour or longer, and such reduction or interruption is not due to conditions on the Customer's system, the demand charge for the month shall be appropriately reduced.

July 1, 1975

UNITED STATES
DEPARTMENT OF THE INTERIOR
SOUTHEASTERN POWER ADMINISTRATION
WHOLESALE POWER RATE SCHEDULE KP-2-B

Availability:

This rate schedule shall be available to the Carolina Power and Light Company and the Virginia Electric and Power Company (either one of which is hereinafter called the Company).

Applicability:

This rate schedule shall be applicable to electric capacity and energy generated at the John H. Kerr and Philpott Projects (hereinafter called the Projects) and sold under appropriate contracts between the Government and the Company.

Character of Service:

Electric capacity and energy delivered to the Company will be 3-phase alternating current at a nominal frequency of 60 Hertz delivered at points of delivery specified by appropriate contract.

Monthly Rate:

The monthly rate for capacity and energy sold under this rate schedule shall be:

Demand Charge:

\$1.25 per kilowatt per month for dependable capacity made available to the Company for their own use.

Energy Charge:

An amount for dump energy equal to eighty percent (80%) of the calculated saving in the cost of fuel for the Company's operating generating units due to the generation avoided therein by the delivery of such dump energy; provided, that the procedures to determine saving in the cost of fuel will be agreed upon from time to time by the Government and the Company.

Billing Month:

End-of-month meter readings shall be made at 12:00 midnight at the end of the calendar month where meters are located in continuously attended power plants and substations.

Service Interruptions:

When the dependable capacity available to the Company is reduced or interrupted for 1 hour or longer during on-peak hours and such reduction or interruption is not due to conditions on the Company's system, or in the case of Philpott, the Appalachian Power Company's or the Company's system, or agreed to outages, the dependable capacity to be paid for by the Company for that month shall be reduced for billing purposes for each on-peak hour (the nearest number of whole hours) that dependable capacity available to the Company is reduced or interrupted by an amount equal to one/(number of on-peak hours in the month) times such reduction in kilowatts of dependable capacity. In the event such reduction in dependable capacity to be paid for by the Company should be greater than the dependable capacity sold to the Company in any month, any such excess shall be applied to the dependable capacity sold to the Company in subsequent months. If such reduction or interruption results in a total delivery of energy in that month to or for the account of the Company's system by the Government amounting to less than the total declared available, the declaration of energy for that month shall be reduced for accounting purposes to the amount actually delivered. On-peak hours shall be the hours between 8:00 a.m. and 10:00 p.m. on all days except Sunday.

Power Factor:

The Company shall take power and energy from the Government at such power factor as will best serve the Company's system from time to time; provided, that the Company shall not impose a power factor of less than .85 lagging on the Government's facilities which requires operation contrary to good operating practice or results in overload or impairment of such facilities or unreasonably interferes with the delivery of power and energy by the Government to its other customers.

Termination of Contract:

The Company shall pay the Government 5.00 mills per kilowatthour for energy remaining in the energy bank and remaining as a net debit balance in the storage

account at the termination of the contract between the Government and the Company.

July 1, 1975

**UNITED STATES
DEPARTMENT OF THE INTERIOR
SOUTHEASTERN POWER ADMINISTRATION
WHOLESALE FIRM POWER RATE SCHEDULE
JHK-1-C**

Availability:

This rate schedule shall be available to public bodies and cooperatives (any one of which is hereinafter called the Customer) within a 165 mile radius of the existing interconnection point between the Virginia Electric and Power Company and the Carolina Power and Light Company (hereinafter called the Company) at the Virginia-North Carolina State line in the vicinity of John H. Kerr Project (hereinafter called the Project), purchasing power from the Project in wholesale quantities under appropriate contracts and served through the facilities of the Company.

Applicability:

This rate schedule shall be applicable to Project firm power and accompanying energy, purchased in wholesale quantities under appropriate contracts for a specified number of kilowatts of capacity and shall be applied to each Customer's system consisting of one or more delivery points.

Character of Service:

Electric capacity and energy supplied hereunder will be 3-phase alternating current at a nominal frequency of 60 Hertz delivered at existing or future delivery points on the Company's transmission and distribution system.

Monthly Rate:

The monthly rate for capacity and energy sold under this rate schedule shall be:

Demand Charge:

\$1.25 per kilowatt of contract demand.

Energy Charge:

5.00 mills per kilowatt-hour.

An additional rate for wheeling service provided under this rate schedule shall be:

Wheeling Charge:

\$0.56 per kilowatt of contract demand.

Contract Demand:

The contract demand is the amount of capacity in kilowatts stated in the contract which the Government

is obligated to supply and the Customer is entitled to receive.

Energy to be Furnished by the Government:

(a) If the Customer does not own or operate generating facilities (other than mobile generating equipment used for emergency purposes), the Government will supply Project energy to such Customer each month, to the extent that such energy is available, based on the ratio of the Customer's energy requirements (determined by multiplying the Customer's total energy requirements at all points of delivery located within 165 miles of the existing interconnection point between the Company and VEPCO at the Virginia-North Carolina State line in the vicinity of the Project by the ratio of the Customer's contract demand to its maximum 30-minute integrated measured demand for that month at said points of delivery) to the sum of the individual energy requirements of all such Customers purchasing under this rate schedule determined on this same basis. (The maximum 30-minute integrated measured demand of the Customer for the month shall be determined by adding together the highest 30-minute integrated measured demand at each point of delivery located within 165 miles of the aforementioned interconnection point, exclusive of abnormal nonrecurring demands resulting from transfer of loads from one point of delivery to another where such transfers are previously approved by the Company.)

(b) If the Customer owns or operates generating facilities (other than mobile generating equipment used for emergency purposes), the Government will supply Project energy each month in an amount determined by multiplying the ratio of the Customer's contract demand to the dependable capacity made available to the Company's system from the Project by 100/106 of the total energy (exclusive of dump energy) declared and made available to the Company's system from the Project.

Energy Accounting:

For the purposes of energy accounting an energy bank shall be maintained, and the Government shall keep the official record of such account. In any month in which the total Project energy (exclusive of dump energy) declared and made available by the Government to the Company exceeds the energy accounted for in such month as accompanying the capacity required to meet the contract demands of the Government to preference customers, increased by six percent (6%) to provide for losses in transmission, such remaining energy shall be credited to the energy bank. Energy stored in this energy bank shall be used in subsequent months to supply to the extent possible preference customer energy requirements not supplied by energy declared and made available from the Project during such months. Withdrawals of energy from the energy bank shall reduce the bank account and shall be accounted for as Project energy available to be transmitted by the Company to the preference customers for the account of the Government.

In those months when Project energy (including energy available from the energy bank) multiplied by 100/106 is equal to or more than the total energy requirements of preference customers of the Government, all such energy requirements shall be deemed to have been supplied from the Project and transmitted by the Company for the account of the Government. In those months when Project energy (including energy available from the energy bank) multiplied by 100/106 is less than the total energy requirements of preference customers of the Government, the quantity of energy which shall be deemed to have been transmitted by the Company for the account of the Government shall be 100/106 of the total Project and bank energy available for transmission. In such months each preference customer of the Government that owns or operates generating facilities (other than mobile generating equipment used for emergency purposes) shall receive a portion of the available energy that results from multiplying the ratio of each such Customer's contract demand to the dependable capacity made available to the Company's system by 100/106 of the total energy declared and made available to the Company's system (excluding energy available from the energy bank), and each of the other preference customers of the Government shall receive a proportionate part of the remaining available energy based on the ratio of such Customer's individual energy requirements (determined by multiplying each such Customer's total energy requirements at all points of delivery by the ratio of its contract demand to its maximum 30-minute integrated measured demand for the month at said points of delivery) to the sum of the individual energy requirements of all such preference customers determined on this same basis.

Billing Month:

End-of-month meter readings for billing under this schedule shall be made on the last regular working day of each month or as near thereto as may be practicable.

Conditions of Service:

(a) *Parallel Operation:*

The Government may condition service to the Customer upon payment by the Customer to the Company of the cost of such facilities, including special meters, as are made necessary by the Customer's operation of any generating facilities in parallel with the Company's system and in such event will require the operation and maintenance of such facilities by the Customer in accordance with good operating practices.

(b) *Energy Scheduling:*

If the Customer owns or operates generating facilities (other than mobile generating equipment used for emergency purposes), it shall schedule and receive its proportionate share of the minimum monthly declarations of energy as provided in the contract between the Government and the Company dated March 30, 1973, in quantities reasonably distributed over the period of

declaration. In the event energy in addition to minimum is available at the Project, the Customer shall receive its proportionate share of any excess energy so declared during the period for which it is declared.

(c) *Service Interruption:*

When energy delivery to the Customer's system is reduced or interrupted for 1 hour or longer, and such reduction or interruption is not due to conditions on the Customer's system, the demand charge for the month shall be appropriately reduced.

(d) *Power Factor:*

If the Customer owns or operates generating facilities (other than mobile generating equipment used for emergency purposes), the Customer will so utilize its generating units and power factor corrective equipment as to minimize its reactive requirements; provided, however, that unless otherwise specifically agreed, the Government will not be obligated to make available for delivery power and energy to the Customer at any time at a power factor below .85 lagging.

October 1, 1981

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR
CONSERVATION AND RENEWABLE ENERGY

In the Matter of:

Western Area Power Admin. —) Rate Order
istration) No. WAPA-10
Central Valley Project Power
Rates

ORDER CONFIRMING AND APPROVING AN
EXTENSION OF POWER RATES ON AN
INTERIM BASIS
(September 16, 1981)

Pursuant to Section 302(a) of the Department of Energy Organization Act, 42 U.S.C. 7152(a), the power marketing functions of the Secretary of the Interior, under the Reclamation Act of 1902, 43 U.S.C. 372, *et seq.*, as amended and supplemented by subsequent enactments, particularly by Section 9(c) of the Reclamation Act of 1939, 43 U.S.C. 485h(c), for the Bureau of Reclamation were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 FR 60636 (December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve, and place in effect such rates on an interim basis, and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary

under the delegation. Due to a Department of Energy organizational realignment on February 24, 1981, this authority of the Assistant Secretary for Resource Applications has been transferred to the Assistant Secretary for Conservation and Renewable Energy. This rate order is issued pursuant to the amendment of Delegation Order No. 0204-33 to transfer the delegation to the Assistant Secretary for Conservation and Renewable Energy, effective March 19, 1981.

BACKGROUND

Pursuant to Delegation Order No. 0204-33, on October 2, 1979, the Assistant Secretary for Resource Applications issued Rate Order No. WAPA-2 (44 FR 57962, October 9, 1979) confirming and approving on an interim basis, effective November 1, 1979, Rate Schedules CV-F4 and CV-P3 for power marketed by the Western Area Power Administration's (Western) Central Valley Project (CVP). The rate order stated that the rates "... shall remain in effect on an interim basis for a period of 12 months unless such period is extended or until the FERC confirms and approves them, or substitute rates, on a final basis." The rate schedules were submitted to the FERC for confirmation and approval on a final basis by the Assistant Secretary's letter of October 2, 1979. By Rate Order No. WAPA-5 (45 FR 67442, October 10, 1980), the rates were extended for 12 months, through October 31, 1981.

DISCUSSION

The FERC has not yet acted on the CVP power rates submitted to the FERC on October 2, 1979. It appears that unless the rates are extended they will terminate on October 31, 1981.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, effective November 1, 1981, an extension of existing Rate Schedules CV-F4 and CV-P3. These rates shall remain in effect through October 31, 1982, unless extended, or until the FERC confirms and approves them, or substitute rates, on a final basis.

Issued in Washington, DC, September 16, 1981.

Joseph J. Tribble
Assistant Secretary
Conservation and Renewable Energy

Rate Schedule CV-F4
(Supersedes Rate
Schedule CV-F3R)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

Central Valley Project, California

SCHEDULE OF RATES FOR WHOLESALE FIRM POWER SERVICE

Effective:

November 1, 1979.

Available:

In the area served by the Central Valley Project.

Applicable:

To wholesale firm power customers for general power service supplied through one meter at one point of delivery.

Character and Conditions of Service:

Alternating current, sixty hertz, three phase, delivered and metered at the voltages and points established by contract.

Monthly Rate:

Demand Charge:

\$2.00 per kilowatt of billing demand.

Energy Charge:

5.11 mills per kilowatt-hour for all energy use up to, but not in excess of, the energy obligation under the power sales contract.

Billing Demand:

The billing demand will be the highest 30-minute integrated demand established during the month up to, but not in excess of, the delivery obligation under the power sales contract.

Energy Obligation:

The maximum kilowatt-hour obligation of the United States during the month as established under the power sales contract.

Minimum Bill:

\$2.00 per kilowatt of the effective contract rate of delivery.

Billing for Unauthorized Overruns:

For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual power and/or energy obligations, such overrun shall be billed at ten times the above rate.

Adjustments

For character and conditions of service:

If delivery is made at transmission voltage so that the United States is relieved of substation costs, five percent discount will be allowed on the demand and energy charges.

For transformer losses:

If delivery is made at transmission voltage but

metered on the low-voltage side of the substation, the meter readings will be increased two percent to compensate for transformer losses.

For power factor:

None. The customer will normally be required to maintain a power factor at the point of delivery of between 95 percent lagging and 95 percent leading.

Rate Schedule CV-P3
(Supersedes Rate
Schedule CV-P2R)

UNITED STATES DEPARTMENT OF ENERGY WESTERN AREA POWER ADMINISTRATION

Central Valley Project, California

SCHEDULE OF RATES FOR COMMERCIAL IRRIGATION AND/OR DRAINAGE PUMPING SERVICE AND FOR WHOLESALE FIRM POWER SERVICE WHEN SUPPLIED IN CONJUNCTION THEREWITH

Effective:

November 1, 1979.

Available:

In the area served by the Central Valley Project.

Applicable:

To commercial irrigation customers for their own use for, or for resale for, irrigation and/or drainage pumping and purposes incidental thereto supplied through one meter at one point of delivery, and for the purposes other than irrigation and/or drainage pumping service when supplied in conjunction with the pumping service through the same meter at the same point of delivery.

Character and Conditions of Service:

Alternating current, sixty hertz, three phase, delivered and metered at the voltages and points established by contract.

Monthly Rate:

Demand Charge:

\$2.00 per kilowatt of billing demand.

Energy Charge:

5.11 mills per kilowatt-hour for all energy use up to, but not in excess of, the energy obligation under the power sales contract.

Billing Demand:

The billing demand will be the highest 30-minute integrated demand established during the month up to, but not in excess of, the delivery obligation under the power sales contract.

Energy Obligation:

The maximum kilowatt-hour obligation of the United States during the month as established under the power sales contract.

Minimum Bill:

None.

Billing for Unauthorized Overruns:

For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual power and/or energy obligations, such overrun shall be billed at ten times the above rate.

Adjustments

For character and conditions of service:

If delivery is made at transmission voltage so that the United States is relieved of substation costs, five percent discount will be allowed on the demand and energy charges.

For transformer losses:

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

For power factor:

None. The customer will normally be required to maintain a power factor at the point of delivery of between 95 percent lagging and 95 percent leading.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR CONSERVATION
AND RENEWABLE ENERGY

In the Matter of:

Southeastern Power Admin-
istration

—) Rate Order

Georgia-Alabama System of Projects) No. SEPA-12
Power Rates)

ORDER CONFIRMING AND APPROVING
SUBSTITUTE POWER RATES ON AN INTERIM
BASIS

(December 18, 1981)

Pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act, Public Law 95-91, the functions of the Secretary of the Interior and the Federal Power Commission under Section 5 of the Flood Control Act of 1944, 16 U.S.C. 825s, relating to the Southeastern Power Administration (SEPA) were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979, 43 F.R. 60636 (December 28, 1978), the Secretary of Energy delegated

to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve, and place in effect such rates on an interim basis and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. Due to a Department of Energy organizational realignment, Delegation Order No. 0204-33 was amended, effective March 19, 1981, to transfer the authority of the Assistant Secretary for Resource Applications to the Assistant Secretary for Conservation and Renewable Energy. This rate order is issued pursuant to the delegation to the Assistant Secretary for Conservation and Renewable Energy.

BACKGROUND

New Contractual Arrangement

Power from the Georgia-Alabama System of Projects is presently sold under several Wholesale Power Rate Schedules including Schedules CAR-1-B and CAR-2-B applicable to power sold to preference customers within the Duke Power Company (Duke) service area and to the Company. These system rates were confirmed and approved by the Federal Energy Regulatory Commission on April 3, 1981, for a period ending September 30, 1983. Anticipating the expiration of its current contract with Duke and to begin the implementation of new written power marketing policy for its Georgia-Alabama System, SEPA has negotiated a new contract with Duke whereby the Company agrees for a stated wheeling fee to transmit for the account of the Government to preference customers all peaking power available to the Duke system area after provision for capacity reserves and transmission losses. Under the contract, Duke will no longer purchase power from SEPA. Contracts consistent with the SEPA-Duke contract are being negotiated by SEPA with each preference customer. The SEPA-Duke contract and the SEPA preference customer contracts will become effective concurrent with the date FERC approves and/or accepts for filing the Duke wheeling charge to SEPA. SEPA proposes to eliminate the existing rate schedules applicable to the sale of power to preference customers and to Duke and to substitute a single rate schedule applicable only to the preference customers.

Public Notice and Comment

SEPA prepared a Repayment Study, dated September 1981, for the Georgia-Alabama Projects which shows that, apart from the impact of the new SEPA-Duke contract, revenues at current rates were adequate to meet repayment criteria for the period covered by the present FERC approval. To reflect the impact of the new contract, a replacement schedule was developed designated Rate Schedule CAR-1-C, through which resulting additional contract costs would be passed directly through

to affected customers as a part of the capacity charge for power sold under such schedule.

Opportunities for public review and comment on the proposed Rate Schedule CAR-1-C and supporting documents were announced by Notice published in the Federal Register of August 24, 1981, 46 F.R. 42748, and all affected SEPA customers were notified by mail. Pursuant to the Notice a public information and comment forum was held in Spartanburg, South Carolina, on September 24, 1981, and written comments were solicited through October 9, 1981. No comments were received. A transcript of the public forum was made.

DISCUSSION

System Repayment

SEPA's September 1981 system Repayment Study is basically an update of its 1979 Repayment Study, upon which existing rates are predicated. While the cost estimates used in the 1981 Study are slightly higher than the estimates included in the 1979 Study, nevertheless, the 1981 Repayment Study continues to show that the revenues at present rate levels are adequate, apart from the impact of the new SEPA-Duke contract, to recover all costs within the repayment criteria. To recover the additional costs resulting from the new SEPA-Duke contract, Rate Schedule CAR-1-C has been designed as a replacement schedule to provide revenues equivalent to the revenues currently received under existing Rate Schedules CAR-1-B and CAR-2-B applicable to the Duke area preference customers and the Company plus the additional wheeling charge under the new contract payable to Duke.

Rate Design

Proposed Rate Schedule CAR-1-C is identical to existing Rate Schedule CAR-1-B except that the capacity charge is increased from \$1.02 to \$2.51 per kilowatt per month of contract demand. \$0.23 of the increased charge is required because the new contract provides for the sale of 118,500 kilowatts of net assured capacity to preference customers while the contract being replaced provided for the sale of 145,000 kilowatts of dependable capacity to the preference customers (61,500 kW) and Duke (83,500 kW). The additional revenues required which amount to \$1,794,000 per year result from wheeling the total power to the preference customers at transmission costs derived from costs of service studies. This accounts for the remaining \$1.26 per kilowatt per month charge for a total of \$2.51. Since no sales to the Company are made under the new SEPA-Duke contract, Rate Schedule CAR-2-B now applicable to Duke is eliminated as is Rate Schedule CAR-1-B now applicable to preference customers in the Duke area.

Environmental Impact

SEPA has reviewed the possible environmental impacts of the rate adjustments under consideration and has con-

cluded that because the increased rates would not significantly affect the quality of the human environment within the meaning of the National Environmental Policy Act of 1969, the proposed action is not a major Federal action for which preparation of an Environmental Impact Statement or an Environmental Assessment is required.

Availability of Information

Information regarding these rates including studies, public information and comment forum transcript, and other supporting material are available for public review in the offices of Southeastern Power Administration, Samuel Elbert Building, Elberton, Georgia 30635, and in the Office of the Director of Power Marketing Coordination, 12th and Pennsylvania Avenue, N. W., Washington, D.C. 20461.

Submission to the Federal Energy Regulatory Commission

The rates herein confirmed and approved on an interim basis, together with supporting documents, will be submitted promptly to the Federal Energy Regulatory Commission for confirmation and approval on a final basis for a period ending no later than September 30, 1983.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, to become effective concurrent with the effective date of the Duke wheeling charge to Southeastern, attached Wholesale Power Rate Schedule CAR-1-C. The Rate Schedule shall remain in effect on an interim basis for a one-year period unless such period is extended or until the FERC confirms and approves Rate Schedule CAR-1-C or a substitute rate schedule on a final basis, whichever occurs first. Subject to final action by FERC, Rate Schedules CAR-1-B and CAR-2-B will terminate on the effective date of Rate Schedule CAR-1-C.

Issued at Washington, D.C., this 18th day of December, 1981.

Joseph J. Tribble
Assistant Secretary
Conservation and Renewable Energy

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHEASTERN POWER ADMINISTRATION
**WHOLESALE POWER RATE SCHEDULE
CAR-1-C**

Availability:

This rate schedule shall be available to public bodies and cooperatives (any one of which is hereinafter called the Customer) in North Carolina and South Carolina to

whom power may be wheeled pursuant to contract between the Duke Power Company (hereinafter called the Company) and the Government.

Applicability:

This rate schedule shall be applicable to power and accompanying energy generated at the Hartwell and Clarks Hill Projects (hereinafter called the Projects) and sold in wholesale quantities.

Character of Service:

The electric capacity and energy supplied hereunder will be three-phase alternating current at a nominal frequency of 60 cycles per second delivered at the delivery points of the Customer on the Company's transmission and distribution system. The voltage of delivery will be maintained within the limits established by the state regulatory commission.

Monthly Rate:

The monthly rate for capacity and energy sold under this rate schedule shall be:

Demand Charge:

\$2.51 per kilowatt of total contract demand.

Energy Charge:

3.65 mills per kilowatt-hour.

Energy to be Furnished by the Government:

The Government will sell to the customer and the customer will purchase from the Government a portion of the energy available to the Company area from the Projects in any billing month determined by multiplying the total energy available less six and one-half percent losses by the ratio of the customer's contract demand to the sum of the contract demands of all customers served under this rate schedules.

Billing Month:

The billing month for power sold under this schedule shall end at 12:00 midnight on the 20th day of each calendar month.

Conditions of Service:

The customer shall at its own expense provide, install, and maintain on its side of each delivery point the equipment necessary to protect and control its own system. In so doing, the installation, adjustment and setting of all such control and protective equipment at or near the point of delivery shall be coordinated with that which is installed by and at the expense of the Company on its side of the delivery point.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ASSISTANT SECRETARY FOR CONSERVATION
AND RENEWABLE ENERGY

In the Matter of:

Western Area Power Administra- —) Rate Order
tion) No. WAPA-7,
Colorado River Storage Project
Power Rates

ORDER CONFIRMING AND APPROVING AN
EXTENSION OF POWER RATES ON AN INTERIM
BASIS

(December 18, 1981)

Pursuant to section 302(a) of the Department of Energy Organization Act, 42 U.S.C. 7152(a), the power marketing functions of the Secretary of the Interior under the Reclamation Act of 1902, 43 U.S.C. 372, *et seq.*, as amended and supplemented by subsequent enactments, particularly by section 9(c) of the Reclamation Project Act of 1939, 43 U.S.C. 485(c), and acts specifically applicable to the Colorado River Storage Project, for the Bureau of Reclamation were transferred to and vested in the Secretary of Energy. By Delegation Order No. 0204-33, effective January 1, 1979 (43 FR 60636, December 28, 1978), the Secretary of Energy delegated to the Assistant Secretary for Resource Applications the authority to develop power and transmission rates, acting by and through the Administrator, and to confirm, approve, and place in effect such rates on an interim basis, and delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis or to disapprove rates developed by the Assistant Secretary under the delegation. Due to a Department of Energy organizational realignment, Delegation Order No. 0244-33 was amended, effective March 19, 1981 (46 FR 25426, May 7, 1981), to transfer the authority of the Assistant Secretary for Resource Applications to the Assistant Secretary for Conservation and Renewable Energy. This rate order is issued pursuant to the delegation to the Assistant Secretary for Conservation and Renewable Energy.

BACKGROUND

Pursuant to Delegation Order No. 0204-33, the Assistant Secretary for Resource Applications issued Rate Order No. WAPA-4 on December 23, 1980 (45 FR 86988, December 31, 1980), which confirmed and approved on an interim basis, Rate Schedules SP-F1 and SP-FP1 for wholesale power marketed by the Western Area Power Administration's Colorado River Storage Project. These rates became effective the first day of the first full billing period beginning on or after January 23, 1980. The rate order stated that the rates "...shall remain in effect on an interim basis for a period of 12 months unless such period is extended, or until the FERC confirms and approves these or substitute rates, on a final basis, whichever occurs first." The rate schedules were submitted to the FERC for confirmation and approval on a final basis by the Assistant Secretary for Resource Applications' letter of December 23, 1980.

DISCUSSION

Inasmuch as the FERC is not expected to complete its confirmation and approval of the Colorado River Storage Project power rates by January 23, 1982, a further extension of the interim rates is necessary.

ORDER

In view of the foregoing and pursuant to the authority delegated to me by the Secretary of Energy, I hereby confirm and approve on an interim basis, effective the first day of the first full billing period beginning on or after January 23, 1982, an extension of existing Rate Schedules SP-F1 and SP-FP1. These rates shall remain in effect pending the FERC confirmation and approval of them, or substitute rates, on a final basis, or until they are superseded.

Issued in Washington, D.C., December 18, 1981.

Joseph J. Tribble
Assistant Secretary
Conservation and Renewable Energy

Rate Schedule SP-F1
(Supersedes Schedule UC-FP2)

UNITED STATES
DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
Colorado River Storage Project
**SCHEDULE OF RATES FOR WHOLESALE FIRM
POWER SERVICE**

Effective:

The first day of the first full billing period beginning on or after January 23, 1981.

Available:

In the area served by the Colorado River Storage Project.

Applicable:

To wholesale power customers for general power service supplied through one meter at one point of delivery.

Character and Conditions of Service:

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

Monthly Rate:

Capacity Charge:

\$1.655/kW of billing demand.

Energy Charge:

4.0 mills/kWh for all energy use up to, but not in

excess of, the energy obligation under the power sales contract.

Billing Demand:

The billing demand will be the greater of (1) the highest 30-minute integrated demand established during the month up to, but not in excess of, the delivery obligation under the power sales contract, or (2) the contract rate of delivery.

Billing for Unauthorized Overruns:

For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual firm power and/or energy obligations, such overrun shall be billed at ten (10) times the above rate.

Adjustments:

For transformer losses:

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

For power factor:

None. The customer will normally be required to maintain a power factor at the point of delivery of between 95 percent lagging and 95 percent leading.

Rate Schedule SP-FP1
(Supersedes Schedule UC-FP2)

UNITED STATES
DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
Colorado River Storage Project
**SCHEDULE OF RATES FOR WHOLESALE
PEAKING POWER SERVICE**

Effective:

The first full day of the first full billing period beginning on or after January 23, 1981.

Available:

Within and adjacent to the marketing area of the Colorado River Storage Project.

Applicable:

To wholesale power customers purchasing such service under long-term contracts. Because of the nature of this class of service, it is applicable only to customers with other resources enabling them to utilize it.

Character and Conditions of Service:

As specifically established by contract. Delivery will be made from the transmission system of the United

States at transmission voltage, and normally only during peak hours of the purchaser's load. Return of all energy furnished shall normally be required.

Monthly Rate:

Capacity Charge:

\$1.655/kW of the effective contract rate of delivery for peaking power or the maximum amount scheduled, whichever is the greater.

Energy Charge: 4.0 mills/kWh for all energy scheduled for delivery without return.

Billing for Unauthorized Overruns:

For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual obligation for peaking capacity and/or energy, such overrun shall be billed at ten (10) times the above rate.

Adjustments:

For power factor:

None. The customer will normally be required to maintain a power factor at the point of delivery of between 95 percent lagging and 95 percent leading.

Federal Rates
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY
COMMISSION

Before Commissioners: Charles B. Custis, Chairman;
Georgiana Sheldon, Matthew
Holden, and George R. Hall.

Southeastern Power Administration) Docket No.
EF79-3012

ORDER CONFIRMING AND APPROVING
EXTENSION OF RATES

(Issued January 22, 1980)

On May 2, 1979, the Assistant Secretary for Resource Applications of the Department of Energy confirmed and approved, on an interim basis, a three-month extension of rates previously approved by the Commission.¹ The rates are applicable to hydroelectric power marketed by the Southeastern Power Administration (SEPA) from nine Corps of Engineers multipurpose reservoir projects known as the Georgia-Alabama Projects.²

Pursuant to Section 5 of the Flood Control Act of 1944³ and Delegation Order No. 0204-33 of the Department of Energy, the Assistant Secretary for Resource Applications submitted these interim rates to the Federal Energy Regulatory Commission for confirmation and approval or disapproval on a final basis. Public notice of this filing was published in the Federal Register on August 26, 1979. Protests and petitions to intervene were due on or before September 7, 1979. No protests or petitions were received.

By order issued November 29, 1976, in Docket No. E-7160,⁴ the Commission confirmed and approved on a final basis certain rate schedules for SEPA applicable

to the Georgia-Alabama Projects. These rates, which were approved for the period ending June 30, 1979, have been extended through September 30, 1979, on an interim basis by the Assistant Secretary for Resource Applications. It is this extended period which is the subject of this docket. The Assistant Secretary has also approved on an interim basis new rates for the Georgia-Alabama Projects to cover a period commencing October 1, 1979. Those rates, however, are currently under review and are not the subject of this docket.

We have reviewed SEPA's proposal to extend the previously approved rates through September 30, 1979, and find that such extension is in the public interest. We also find that these rates meet the statutory criterion of being "the lowest possible rates to consumers consistent with sound business principles."⁵ We shall therefore confirm and approve on a final basis the rates recommended by the Assistant Secretary for Resource Applications.

The Commission Orders:

(A) The rates for the sale of hydroelectric power from the Georgia-Alabama Projects by the Southeastern Power Administration, as submitted by the Assistant Secretary for Resource Applications of the United States Department of Energy, are hereby confirmed and approved for the period July 1, 1979 through September 30, 1979.

(B) The Secretary shall promptly publish this order in the Federal Register.

By the Commission.

(S E A L)

Kenneth F. Plumb,
Secretary.

¹ See Department of Energy Rate Order No. SEPA-3, "Order Confirming and Approving Extension of Power Rates on an Interim Basis."

² See Attachment for rate schedule designations.

³ 16 U.S.C. §825s.

⁴ "Order Confirming and Approving Rate Schedules."

⁵ Section 5 of the Flood Control Act of 1944.

ATTACHMENT

<i>Rate Schedule</i>	<i>Used By</i>	<i>Project Supplying Power</i>	<i>Delivery</i>
GAMF-1-A	Public bodies and cooperatives in Georgia, Alabama, Mississippi, and Florida	Allatoona, Buford, Clark Hill, Walter F. George, Hartwell, Millers Ferry, West Point, Jones Bluff, and Carters Projects	Wheeled by Alabama, Georgia, Mississippi or Gulf Power Companies
GAMF-2-A	Georgia, Alabama, Mississippi, and Gulf Power Companies	Same as above	At the projects
ALA-1-A	Alabama Elec. Coop.	Same as above	At the Walter F. George Project
MISS-1-A	South Mississippi Electric Power Assoc.	Same as above	Wheeled by Mississippi Power Company
SC-1 (Revised)	South Carolina Public Service Authority	Clark Hill Project	At the project
SC-2	Public bodies and cooperatives in the service area of the South Carolina Public Service Authority	Clark Hill Project	Wheeled by South Carolina Public Service Authority
CAR-1 (Revised)	Public bodies and cooperatives in the service area of Duke Power Company	Hartwell and Clark Hill Projects	Wheeled by Duke Power Company
CAR-2 (Revised)	Duke Power Company	Hartwell and Clark Hill Projects	At the projects

FEDERAL ENERGY REGULATORY
COMMISSION

Washington 20426

Docket No. ER80-167

Stoel, Rives, Boley, Fraser and Wyse
Attention: Mr. Hugh Smith
900 S.W. Fifth Avenue
Portland, Oregon 97204

Dear Mr. Smith:

On June 18, 1980, the Presiding Administrative certified to the Commission an uncontested Settlement Agreement entered into by all of the parties to the Pacific Northwest Coordination Agreement. The Settlement proposal is in the public interest and is accepted and approved.

The settlement proposal was filed, pursuant to the Rules of Practice and Procedure, 18 CFR 1.18, with evidence that it had been served on all participants listed on file with the Secretary of the Commission. All participants to the proceeding except Commission staff waived their rights to comment on the proposed settlement at the prehearing conference on May 28, 1980. Commission staff filed comments in support of the proposed settlement on June 17, 1980.

On June 17, 1980, the Washington Water Power Company filed a "Motion for Expendited [sic] Action" requesting Commission approval of the Settlement prior to the proposed effective date of July 1, 1980. Commission staff filed a motion in support of that motion on June 18, 1980. Good cause having been shown, the Amendatory Agreement No. 2 to the Pacific Northwest Coordination Agreement is accepted for filing and designated as shown on the Enclosure, to be effective July 1, 1980.

The Commission's approval of this settlement shall not constitute approval of or precedent regarding any principle of issue in this proceeding now pending or hereinafter instituted by or against any of the parties to this proceeding.

This acceptance for filing terminates Docket No. ER80-167.

By direction of the Commission.

Kenneth F. Plumb,
Secretary

Enclosure

SETTLEMENT AGREEMENT DESIGNATIONS

Dated : Undated

Filed : 5/30/80

Effective: 7/1/80

MONTANA POWER COMPANY

Supplement No. 3 to Rate Schedule FERC No. 45
(Supersedes Supplement No. 2)

PACIFIC POWER & LIGHT COMPANY

Supplement No. 3 to Rate Schedule FERC No. 160
(Supersedes Supplement No. 2)

PORTLAND GENERAL ELECTRIC COMPANY

Supplement No. 3 to Rate Schedule FERC No. 31
(Supersedes Supplement No. 2)

PUGET SOUND POWER & LIGHT COMPANY

Supplement No. 3 to Rate Schedule FERC No. 65
(Supersedes Supplement No. 2)

THE WASHINGTON WATER POWER COMPANY

Supplement No. 3 to Rate Schedule FERC No. 97
(Supplement No. 2)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY
COMMISSION

ELECTRIC RATES: Federal Rates

Before Commissioners: Charles B. Curtis, Chairman;
Georgiana Sheldon, Matthew
Holden, Jr., and George R.
Hall.

U.S. Secretary of Energy,) Docket No. EF80-2011
Bonneville Power)
Administration

ORDER REMANDING RATES WITHOUT
PREJUDICE

(Issued November 21, 1980)

INTRODUCTION

Bonneville Power Administration (BPA) is the wholesale marketing agency for electric power generated at the federal hydro-electric dams in the Columbia River Basin. These dams were built and are operated by the Water and Power Resources Service (formerly Bureau of Reclamation) and the Army Corps of Engineers. Together with BPA's transmission system they comprise the Federal Columbia River Power System which supplies about 50 percent of the electric energy consumed in the Pacific Northwest and accounts for about 80 percent of the region's high-voltage transmission capacity. By purchase and exchange, BPA also acquires power generated by non-federal utilities.

BPA sells power to 148 customers, including publicly-owned utilities, privately-owned utilities, state and federal agencies, electro-process industries and other industries located throughout the Northwest. BPA also sells power to thirteen public and private utilities or agencies outside the Northwest.

Between 70 and 80 percent of BPA's sales of firm power are to public and private electric utilities for

resale to ultimate consumers. Many of BPA's utility customers have generation of their own in addition to that power obtained from BPA. BPA also sells to several industries, primarily electro-process industries. In addition, BPA sells secondary energy, subject to availability, to utilities.

The Administrator of the BPA develops rates for BPA power. These are submitted to the Assistant Secretary for Resource Applications (AS/RA) of the Department of Energy (DOE) for confirmation and approval on an interim basis. Thereafter, the rates go to the Federal Energy Regulatory Commission (Commission) for confirmation and approval as final rates pursuant to the Bonneville Project Act of 1937¹, the Flood Control Act of 1944² and DOE Delegation Orders [Order-Ed.] Number 0204-33³.

The Commission presently has before it BPA's system wholesale power rates for a five-year period beginning December 20, 1979. By Order issued December 3, 1979, the responsible official of the Department of Energy, the AS/RA confirmed and approved on an interim basis BPA's wholesale power rate schedules, the general rate schedule provisions setting forth the terms and conditions of service under the rate schedules, and special contract rates and rate schedule provisions. The AS/RA placed them in effect on an interim basis as of December 20, 1979.

The statutory scheme and the applicable delegation orders regarding the power marketing acts place the Commission in a role different from its regulatory responsibility under the Federal Power Act. Prior to the formation of the Department of Energy, the function of confirming and approving or disapproving Bonneville's rates rested with the Federal Power Commission (FPC). After formation of the DOE, this function passed to the Secretary of Energy.⁴ On January 1, 1979, the Secretary of Energy assigned to DOE's AS/RA and to this Commission various responsibilities relating to the rates of power marketing agencies.

¹16 U.S.C. 832.

²16 U.S.C. 825s.

³43 FR 60636, issued December 28, 1978.

⁴On October 1, 1977, the Department of Energy Organization Act (42 U.S.C. §7101 *et. seq.*) became effective, abolishing the FPC. The functions of the FPC under the Bonneville Project Act and other statutes relating to the BPA were transferred to and vested in the Secretary of Energy pursuant to Sections 302(a) and 301(b) of the Department of Energy Organization Act.

By Delegation Order Number 0204-33, the Secretary of Energy delegated to the AS/RA the authority to develop power and transmission rates, acting by and through the Administrator of BPA and to confirm, approve, and place in effect such rates on an interim basis. The Delegation Order also assigned to the Commission the authority to confirm and approve such rates on a final basis or to disapprove those rates developed by the AS/RA. The rate schedules of BPA before the Commission are the first to be considered under the new administrative arrangements.

BONNEVILLE'S PROPOSED RATES

The rates at issue replace rates that were approved by the FPC by order issued August 21, 1975, in Docket No. E-8978, for a period beginning December 20, 1974, and terminating not later than December 20, 1979.⁵ BPA's new rates will result in about 88 percent greater revenues than the old rates. BPA asserts it needs an increase in rates for a number of reasons.

BPA states that since 1974 it has experienced significant increases in the cost of operating and maintaining the federal generation and transmission system, in the cost of constructing new generation and transmission facilities, and in the cost of power purchases. BPA states that these cost increases have not been matched by revenue increases which have been limited to those resulting from an increase in the volume of sales.

Another significant change since the 1974 rate adjustment is that, pursuant to the 1974 Federal Columbia River Transmission System Act,⁶ BPA now operates on a self-financing basis. BPA must pay a rate of interest on the bonds it sells to the United States Treasury to finance the construction of transmission facilities comparable to the current rate for bonds of similar quality sold in the money market. This has resulted in increased interest costs to BPA, as compared with rates of interest previously paid on appropriated funds.

The most significant cost increases, BPA asserts, are the result of construction delays and cost escalation at thermal plants from which BPA has purchased thermal output. BPA has contracted to purchase all or sizable portions of the capacity of four nuclear plants completed or under construction. The contracts provide for BPA to commence payment for its share of plant capacity at fixed dates whether or not the plants are completed or operating on those dates.

Costs for two of these plants, the Trojan facility constructed by Portland General Electric from which BPA acquires Eugene Water and Electric Board's 30 percent ownership share of the capability and the Washington Public Power Supply System's (WPPSS) Plant Number 2 from which BPA will acquire 100 percent of the capability, were included in BPA's 1974 rates. BPA asserts that costs of these plants have increased significantly since 1974. Also, costs of an additional thermal plant, WPPSS Plant Number 1, from which BPA will acquire 100 percent of the capability, are included in the present rates. The costs of the fourth plant, WPPSS Plant Number 3, from which BPA will acquire 70 percent of the capability, will be included in future rate adjustments.

The developments cited by BPA raise complex questions about the overall revenue requirements of BPA. Another complex and controversial area is BPA's proposed allocation of revenue-responsibility among the different BPA rate schedules.

BPA's H-6 rate schedule is particularly controversial. This rate schedule governs the sale of non-firm energy to BPA's non-preference customers. As developed by the Administrator of BPA and approved by the AS/RA, the H-6 rate, unlike the other BPA rate schedules, is premised on a "share-the-savings" concept. Charges for energy under this schedule are set to equal either 50 percent of the decremental cost of the customers' thermal energy that is displaced by energy from BPA or equal to the rate associated with the displaced firm purchase of thermal energy. The maximum charge under the H-6 rate is 20 mills per kilowatt hour and the minimum charge is 6.5 mills per kilowatt hour during peak use periods or 4.5 mills per kilowatt hour during non-peak periods.

The H-6 schedule is a matter of great concern to many of BPA's customers in both the Pacific Northwest and Pacific Southwest service area. Many petitioners assert that the H-6 rate schedule represents a radical departure from past practices and is contrary to the applicable statutory standards which they interpret as requiring that each of BPA's rates be formulated based on the costs of Bonneville to produce the power. Petitioners have also alleged that the H-6 rate will represent a disproportionate percentage increase of approximately 500 percent over the previous H-5 rate schedule for similar services.

The direct service industrial customers have challenged the rates under the IF-2 rate schedule, claiming that it does not properly reflect the interruptible nature of the service that is supplied to them under their contractual arrangements with BPA. The IF-2 rate schedule includes an adjustment that entitles the customer to a credit if that customer's load is restricted by BPA during the operating year. Certain customers have alleged that the

⁵Public notice of the present filing was published in the Federal Register on December 12, 1979. Interested parties were invited to submit written comments to the Commission on or before January 4, 1980. On February 11, 1980, interested parties were afforded the opportunity to file cross-comments in response to previous comments filed in this proceeding. Petitions to intervene were filed by a substantial number of parties.

⁶P.L. 93-454.

rates charged these customers should not differ from rates charged other customers and that the availability credit is too large for the interruptions contemplated.

There are other matters also in controversy with respect to BPA's proposed rates. For example, various customers have also contended that the charges related to BPA's prepayments on the WPPSS Plants through debt financing should be deferred to a period contemporaneous with the commencement of service from these units. According to these customers, if payments were to be deferred until the plants are placed in service, BPA's rate increase would amount to approximately 40 percent rather than 88 percent.

A number of petitioners have raised *Mobile-Sierra*⁷ contract-type questions, alleging that the AS/RA placed BPA's rates into effect prior to the effective date called for under the terms of the contract. Other petitioners have alleged that the new six-hour limitation on capacity under the F-7 rate schedule is contrary to the terms of their contractual agreements with BPA.

Other contentions that have been put forth by customers filing comments in this docket are: that BPA improperly classified costs between capacity and energy; that elimination of the facilities charge in the rate to the wholesale firm preference customers is improper and unjustified; that BPA could unjustly and inappropriately designate a purchaser as a computed demand customer; that a computed demand customer could be unfairly penalized for an unauthorized increase in its usage; that the AS/RA improperly and illegally placed BPA's rates in effect on an interim basis; and that BPA failed to comply with the anti-inflation standards. Many petitioners have requested an opportunity to make oral presentations before the Commission.

THE COMMISSION'S REVIEW RESPONSIBILITIES AND THE PRESENT RECORD

The authority delegated to the Commission from the Secretary of Energy is that of confirming and approving, or disapproving, rates developed by the AS/RA on a final basis. The Commission must insure that the rates confirmed and approved by DOE(AS/RA) on an interim basis satisfy the standards of the Bonneville Project Act and the Flood Control Act. These standards provide that BPA rate schedules must be drawn:

1. Having regard to the recovery of the cost of generation and transmission of such electric energy;
2. So as to encourage the most widespread use of Bonneville power;
3. To provide the lowest possible rates to consumers consistent with sound business principles; and
4. In a manner which protects the interests of the United States in amortizing its investment in the projects within a reasonable period.⁸

Unlike our statutory authority under the Federal Power Act or the Natural Gas Act, the statutory mandate accorded to the Commission under the power-marketing acts does not include the power to modify the rates. The power marketing acts vest the responsibility to develop rates in the first instance in the BPA's Administrator. Those rates are then transmitted to the AS/RA for confirmation and approval on an interim basis. The interim rates and an evidentiary record are then submitted to the Commission for final confirmation and approval, or disapproval. Thus, the Commission's role can be viewed as an appellate one: to affirm, reverse, or remand the rates submitted to it for final review.

Not only is the Commission's function under the power-marketing acts different from its functions under the Natural Gas Act and the Federal Power Act, but the substantive standards it must apply also differ. Under the federal power-marketing statutes, the Commission must determine that proposed rates would provide a sufficient level of revenues to BPA to recover its costs and repay the federal investment within a reasonable period of time. The Commission's review in this matter is based on the supporting data and information submitted by the AS/RA consistent with the statutory standards set forth in the applicable power marketing acts.

The Administrator of BPA prepared a revised power repayment study of the Federal Columbia River Power System to determine the revenues necessary to recover the costs of producing and transmitting the electric power marketed by BPA, and to repay, with interest, the Federal investment in the Federal Columbia River Project as required by statute.⁹ The study supported an 88 percent increase in total revenues over the entire repayment period. The increase in wholesale power rates proposed by BPA plus a future increase in transmission rates are based on this determination. BPA's prior rate schedules would have produced revenues of approximately \$343,100,000 in fiscal year 1980, assuming average water conditions. According to the study, the new rate schedules would have produced approximately

⁷*United Gas Co. v. Mobile Gas Corp.* 350 U.S. 332 (1956); *FPC v. Sierra Pacific Power Company*, 350 U.S. 348 (1956).

⁸16 U.S.C. 822, 825s.

⁹This study was prepared pursuant to the Bonneville Project Act, the Federal Columbia River Transmission System Act, and Section 2 of the Grand Coulee Third Power-House Authorization (P.L. 89-448).

\$645,600,000 in fiscal year 1980 under these same conditions for an increase of \$302,500,000 or 88 percent.

This study and the rest of the record submitted to the Commission by the AS/RA do not, however, provide the requisite support to permit the Commission to affirm that the standards set forth in the Bonneville Project Act and the Flood Control Act have been met and that the overall revenues to be generated by the rates before this Commission are appropriate. The record contains an estimate of revenues from each rate schedule for the time period over which approval is being sought. BPA and the AS/RA, however, have not provided sufficient information to support the derivation of the estimated revenues. For example, the description provided does not contain numerical back-up for the revenue calculations so that the sensitivity of these calculations to the underlying assumptions can be evaluated. Also, the basic source data for the revenue estimates, the "Long-Range Projects of Power Loads and Resources for Thermal Planning", was not provided. Because this support is lacking, it is not possible to verify that the proposed rates will produce the projected revenues, and to test the reasonableness of the assumptions utilized in formulating the revenue estimates. The Commission is therefore unable to determine that the estimated revenues would recover BPA's capital investment allocated to electric power and will appropriately amortize the Government's investment.

With regard to the individual components of BPA's filing, it is necessary that the Commission understand the logic of the allocation of cost and revenue requirements among the various rate schedules. The rationale for the substantially differing cost-revenue relationships of the Non-Firm Energy, Annual Firm Capacity and Industrial Firm Power has not been adequately explained. The Commission has to affirm that the various components of BPA's overall pricing scheme meet the tests set forth in the Bonneville Power Act and the Flood Control Act discussed *infra*. Specifically, the Commission must address whether the rate scheme encourages the widest use of BPA power and provides the lowest rates to consumers consistent with sound business principles.

The Commission emphasizes that its role here is in the nature of an appellate body. However, in order for the Commission to discharge this duty, it must be apparent from the record before us that due process requirements have been met and that the Administrator's program of rate schedules and the decision of the AS/RA are rational and consistent with the statutory standards set forth above. Unfortunately, the record before this Commission lacks the requisite exposition of the logical relationship that the Administrator and AS/RA perceived among the various rate schedules that in sum comprise the overall revenues proposed to be collected by BPA. Moreover, we cannot determine from the record before us the reasons in support of a finding that the relationship among the components is in accord with the applicable statutory standards. Lacking an understand-

ing of these issues, the Commission cannot determine whether BPA's proposed rates are appropriate.

In sum, the record before the Commission does not provide an adequate explanation of how the revenue requirements and relationships among the various rate schedules were determined. Support for empirical projections is lacking. Also, the record does not explain how the total revenues proposed to be collected as well as the division of revenues among rate schedules meet the applicable statutory standard. Therefore, the Commission will remand this record, without prejudice, to the Assistant Secretary of Energy for Resource Applications for supplementation.

THE RECORD ON OTHER ISSUES

Because the Commission is remanding this record, it is unnecessary that the other issues in this proceeding be addressed at this time. However, in order to assist the AS/RA and the various parties during the remand process, the Commission will set forth its current views with respect to the adequacy of the existing record as to other issues in this proceeding.

Many comments have raised issues concerning the consistency between the AS/RA's rate proposals and underlying contractual arrangements between BPA and its customers. In a recent decision of the United States District Court for the District of Columbia, *Arkansas Power & Light Company v. James R. Schlesinger* (Civil Action No. 79-1263, October 20, 1980), the Court held that the Southwest Power Administration (SWPA) was barred from proposing a price increase to one of its customers above the level allowed in a contract between SWPA and that customer. The remand provides an opportunity for the AS/RA, if she desires to do so, to consider allegations that the interim rates for customers of BPA are in violation of any contractual obligations between the parties.

The Commission is not disposed to inquire into the legal authority of the AS/RA to place rates in effect on an interim basis. The Commission's view is that this is a matter for the courts to decide.¹⁰

With regard to BPA's inclusion of debt service on the WPPSS plants, the Commission believes the present record supports a finding that these costs are proper for inclusion in the rates to its customers. BPA entered into contractual arrangements that obligated it to commence paying the fixed costs of WPPSS No. 2 and No. 1 in January, 1977 and January 1980, respectively. BPA's repayment policies, as prescribed by the Department of Energy in Order RA 6120.2,¹¹ require it to make payment of purchased power costs in the year in which they are incurred. BPA does not have the legal authority to borrow money for this purpose, so the Commission

¹⁰This issue was recently addressed by the U.S. District Court for the District of Oregon. See *Pacific Power & Light Co. v. Charles William Duncan, Jr., et al.* (Civil Docket No. 80-82, September 30, 1980).

¹¹Issued September 20, 1979.

regards inclusion of these costs in the present rates to be an appropriate means of providing sufficient revenues for BPA to meet its contractual payments to WPPSS as they come due, and also to meet BPA's statutory obligation to amortize federal investments within a reasonable period of time.

The Commission believes that an adequate basis exists in the present record to support BPA's classifications of costs between capacity and energy. No supplementation is required with respect to this matter.

As to BPA's practice of repaying high interest investments ahead of the required repayment date while deferring repayment in lower interest investments, the current record is not sufficient as to the reasons underlying this practice to enable the Commission to determine the appropriateness of this policy.

Similarly, we note that the existing record does not provide an adequate basis to explain BPA's elimination of the facilities charge for wholesale firm preference customers in light of the fact that some customers have relied upon BPA's past practice of collecting a facilities charge and have purchased their own transformation facilities.

Petitioners have challenged the development of a penalty charge for computed demand customers under the EC-8 rate schedule, arguing that a customer could be unfairly penalized for an unauthorized increase in its computed demand. The Commission believes that the present record provides adequate support for the AS/RA's exercise of her authority in developing this charge that seeks to assure that the customer uses all its own resources to meet its load first or sells its own excess resource capabilities.

Some customers argue that the Commission must reject BPA's rates based on an asserted conflict with the President's Wage and Price Guidelines. The Commission disagrees that the Wage and Price Guidelines authorize this Commission to subrogate its statutory mandates in favor of the Guidelines. As stated in the Guidelines:

The Council recognizes that the prices of most public utilities are already subject to regulation by the Federal Energy Regulatory Commission...and in issuing this price standard, the Council does not intend to supplant their statutory functions and responsibilities....¹²

This policy is similarly applicable to the establishment of federal rates. The Commission believes the BPA's customers have sufficient protection in the statutory requirement that power and energy be disposed of "to encourage the most widespread use thereof *at the lowest possible rates to consumers* consistent with

sound business principles..."¹³ Accordingly, while the Commission is mindful of the Guidelines, if the AS/RA demonstrates that the rates submitted conform with statutory requirements, the Commission need look no further.

Finally, the Commission believes the remand makes a hearing before the Commission unnecessary and inappropriate at this time. The Commission has the authority to institute a hearing whenever necessary. However, the Commission would expect that due process and hearing requirements generally would be satisfied when the proposed rates are being reviewed by the AS/RA, because the responsibility for developing the rates resides with the AS/RA acting by and through the Administrator of BPA, and not with the Commission. The Commission, therefore, does not envision at this time any further hearings before the Commission.

The Commission finds:

The record transmitted by the Assistant Secretary of Energy for Resource Applications is not sufficiently developed to determine whether the rate schedules developed by the Administrator of the Bonneville Power Administration and placed into effect by the AS/RA have been drawn on a basis consistent with the statutory standards set out in the relevant power marketing acts. Therefore, it is necessary to remand the record for further development of the basis on which estimates of the revenues were made and an explanation of the relationship among the various rate schedules.

The Commission orders:

(A) The rates and charges developed by the Administrator of the Bonneville Power Administration and placed in effect by the Assistant Secretary of Energy for Resource Applications are hereby remanded without prejudice for further development of the record in order to demonstrate that said rates and charges are in accordance with the applicable statutory standards.

(B) The Secretary shall promptly publish this Order in the Federal Register.

By the Commission.

(SEAL)

Kenneth F. Plumb,
Secretary

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY
COMMISSION

Before Commissioners: Charles B. Curtis, Chairman;
Matthew Holden, Jr., George
R. Hall and J. David Hughes

¹²44 FR 17913, March 23, 1979 (6 CFR 705).

¹³Flood Control Act of 1944, 16 U.S.C. 825s (emphasis added).

ORDER REMANDING RATES WITHOUT
PREJUDICE

(Issued December 1, 1980)

On July 30, 1976, the Secretary of Interior, on behalf of Bonneville Power Administration (BPA) filed with the Federal Power Commission (FPC) a request for confirmation and approval of certain transmission rates for the transmission of non-federal power and energy over BPA's transmission facilities. The filing was docketed as Docket No. E-9563.

Public notice of the filing was issued on August 11, 1976, providing that protests and interventions be submitted before September 10, 1976. By FPC order issued October 5, 1976 intervention was granted to Idaho Power Company, Montana Power Company, Pacific Power & Light Company, the Public Utilities Commissioner of Oregon, Portland General Electric Company, Puget Sound Power & Light Company, the Public Power Council and City of Seattle, Washington, and Washington Water Power Company.

BPA's filing was the first made pursuant to the Federal Columbia River Transmission System Act, 16 U.S.C.A. §838 (1974). [Ed] On January 9, 1977, the Secretary of Interior, on behalf of BPA, filed an amendment to its proposed transmission rate schedules requesting that the proposed rates be made effective immediately on an interim basis, subject to retroactive confirmation, or subject to higher or lower retroactive adjustment, with interest in accordance with such amended or modified rates as would be subsequently approved by the FPC.

By Order issued June 10, 1977 the FPC conditionally approved and confirmed BPA's proposed transmission rates through June, 1978. The rates were subject to retroactive adjustment with interest in accordance with such amendments or modified rates as the FPC might thereafter approve. In addition, the docket was set for evidentiary hearing. On July 11, 1977, petitions for rehearing of the FPC's order were filed.

The FPC on July 28, 1977 denied rehearing of its June 10, 1977 order. By order of September 22, 1977, the FPC granted late intervention to BPA's direct service industrial customers, and to the Department of Water & Power of the City of Los Angeles. The FPC further stated that a prehearing conference had been held on July 11, 1977 at which certain procedural dates were established, including commencement of an evidentiary hearing on March 14, 1978.

No hearing, however, was convened prior to October 1, 1977, when the Department of Energy Organization Act, 42 U.S.C. §7101 *et seq.*, became effective, abolishing the FPC. This Act transferred all of the functions of the Secretary of Interior and the FPC relating to establishment, confirmation and approval of federal power

marketing rates to the Secretary of Energy. By Department of Energy Delegation Order No. 0204-4, Paragraphs 15 and 16, confirmation and approval authority of power marketing agency rates was delegated to the Administrator of the Economic Regulatory Administration. Docket No. E-9563 was transferred from the Commission to the Jurisdiction of the Economic Regulatory Administration, which redesignated the docket as Docket No. ERA No. BPA-78-2 and on July 6, 1978 extended the conditional confirmation and approval of the proposed transmission rates through June 30, 1979 (43 F.R. 29163).

On May 12, 1979, the Assistant Secretary of Energy for Resource Applications (AS/RA) issued an order extending the effectiveness of the interim transmission rates pending final confirmation and approval. No final confirmation and approval order of the Economic Regulatory Administration or the Secretary of Energy was issued.

On January 1, 1979, pursuant to the Department of Energy Delegation Order 0204-33, the Secretary of Energy delegated to the AS/RA the authority to develop power and transmission rates and to confirm, approve, and place in effect such rates on an interim basis. The Delegation Order also assigned to the Commission the authority to confirm and approve such rates on a final basis or to disapprove these rates developed by the AS/RA.

Pursuant to that order, Docket No. E-9563 (ERA Docket No. BPA 78-2) became subject to final confirmation and approval by this Commission. Upon notice to all parties, an informal conference was convened in Portland, Oregon on February 15, 1979 to discuss the status of the case as well as to explore procedures or alternatives of bringing the case to final resolution.

Those discussions and further discussions on general procedures regarding federal power marketing rates failed to result in a consensus regarding procedures or to resolve the issues raised in the docket. The Commission, therefore, on May 30, 1980 issued an order establishing briefing dates, requesting all parties to the proceeding to file briefs and comments with regard to the following questions:

- (1) What is the scope and standard of Commission review under Section 10 of the Federal Columbia River Transmission System Act?
- (2) What procedure should be followed by the Federal Energy Regulatory Commission in determining that the standards of Section 10 of the Federal Columbia River Transmission System Act have been met?

Initial briefs were filed in response by Puget Sound Power & Light Company, Pacific Power & Light Company, Portland General Electric Company, Idaho Power Company, the Washington Water Power Company and the Montana Power Company; collectively, the

Intercompany Pool or ICP Companies, the Los Angeles Department of Water & Power, the Colorado River Service Industrial Customers, the City of Seattle-Washington, the Public Power Council, the Colorado River Energy Distributors Association, San Diego Gas & Electric Company and BPA for the Secretary of Energy. In addition, reply briefs were filed by Los Angeles Department of Water & Power, the ICP companies and BPA for the Secretary of Energy.

The briefs filed by the ICP Companies, the Los Angeles Department of Water & Power, the Colorado River Energy Distributors Association, San Diego Gas & Electric Company, and the City of Seattle indicate their belief that the Commission, before approving and confirming BPA's transmission rates, must independently determine whether the costs of transmission are equitably allocated between federal and non-federal use.

BPA, the Direct Industrial Customers, and the Public Power Council indicate their belief that the Commission has no authority to use independent methods to review cost allocation, but rather has authority only to review the Secretary's cost allocation to determine that the Secretary's decision is reasonable and not arbitrary and capricious.

The Commission has recently discussed its review responsibilities under power marketing acts in *Bonneville Power Administration*, Docket No. EF80-2011 issued November 21, 1980. Therein the Commission determined that its role could be viewed as in the nature of an appellate one; to affirm, reverse, or remand the rates submitted to it for final review. In order for the Commission to discharge this review function, it must be apparent from the record before the Commission that due process requirements have been met and that the Administrator's program of rate schedules and the AS/RA's decision is rational and is consistent with the statutory standards.

Under the federal power marketing statutes, the Commission must determine whether the rate schedules would provide a sufficient level of revenue to BPA to recover its capital costs and repay the Federal investment within a reasonable period of time. The Commission's review in this matter is based on the supporting data and information submitted to the Commission by the AS/RA.

The Commission must also make a determination as to whether, the rates developed by the Administrator have been drawn with the view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles. The foregoing standards are consistent with the standards set forth in Section 9 of the Federal Columbia River Transmission System Act under which the rates herein are being reviewed. In addition Section 10 of the Federal Columbia River Transmission System Act provides that recovery of the cost of the federal transmission system shall be equitably allocated

between federal and non-federal power users utilizing such system.

Pursuant to the statutory standards of both sections 9 and 10 of the Federal Columbia River Transmission System Act, if the Commission can make the determination that the rate schedules have been constructed on a rational basis consistent with the statutory standards, then the Commission will confirm and approve the rates on a final basis. Conversely, if no rational basis is provided upon which the Commission can determine that the statutory standards have been met, then the rates will be remanded or disapproved.

The Commission has the authority to order a hearing when deemed appropriate. However, the Commission would expect that due process and hearing requirements would generally be satisfied when the proposed rates are being reviewed by the AS/RA, since the responsibility for developing the rates resides with the AS/RA acting by and through the Administrator of BPA, and not with the Commission.

The Commission in the instant case is unable to determine, based on the filing before it, whether the rates established by the AS/RA are constructed on a rational basis.

Certain deficiencies in the filing in this docket have precluded the Commission from reaching a conclusion that the filed rates should be confirmed and approved or disapproved. Those areas that require additional information, explanation, or support include the following:

- (1) a demonstration of the rational basis for the AS/RA's determination of the annual cost of the transmission system.
- (2) a demonstration of the rational basis for the AS/RA's determination that annual costs have been equitably allocated between Federal and non-Federal system users;
- (3) justification and ratemaking rationale to support the use of airline mileage billing determinants used in Bonneville rate schedule filing designated FPT-1 as contrasted to circuit mile cost supported type rates. In addition, an explanation, including calculations, of how the revenue figures were derived in support of the proposed rate schedules are necessary.

The Commission having found that the record transmitted by BPA is not sufficiently developed to allow this Commission to determine whether the rates established by the AS/RA are or are not consistent with the applicable statutory criteria, it will remand the record to the AS/RA for purposes of further development.

The Commission Orders:

(A) The rates and charges developed by the Administrator of BPA and placed into effect by the AS/RA

are hereby remanded without prejudice. In further development of the record in order to demonstrate that said rates and charges are in accordance with applicable statutory standards.

(B) The Secretary shall promptly publish this order in the Federal Register.

By the Commission.

(SEAL)

Kenneth F. Plumb,
Secretary

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY
COMMISSION

ELECTRIC RATES: Confirmation of Federal Rates

Before Commissioners: Charles B. Curtis, Chairman;
Matthew Holden, Jr. and J.
David Hughes.

Alaska Power Adminis- —) Docket No. EF79-1021
tration)
Snettisham Project

ORDER CONFIRMING AND APPROVING
LONG-TERM RATES
(Issued December 2, 1980)

On March 15, 1979, the Assistant Secretary for Resource Applications (RA) of the Department of Energy (DOE) tendered for filing, on behalf of the Alaska Power Administration (APA), a request for confirmation and approval of Rate Schedule SN-F-1 for wholesale firm power service from the Snettisham Project.¹ These rates, which would remain effective until November 30, 1983, were approved by RA Rate Order No. APA-1, issued March 9, 1979, to become effective April 1, 1979, on an interim basis for twelve months. 44 F.R. 16470 (March 1979). An extension of these rates was approved by RA Rate Order No. APA-3 issued March 20, 1980, on an interim basis for an additional twelve months, unless such period is further extended by the Assistant Secretary or until the rates are confirmed and approved on a final basis by this Commission.

Notice of the filing was published in the Federal Register on May 4, 1979, 44 F.R. 26150. Interested persons were invited to submit written comments to the Commission on or before May 16, 1979. No com-

ments, protests or petitions to intervene were received.

The rates and charges proposed in Rate Schedule SN-F-1, 15.6 mills per kilowatt-hour for energy to Juneau area consumers, are the same as the existing rates and charges previously approved on a final basis by the Secretary of the Interior for the five-year period from December 1, 1973 through November 30, 1978. They are also the same as rates approved on a final basis by the Assistant Secretary of DOE for the four month period from December 1, 1978 through March 31, 1979.²

Background

The Snettisham Project is a single-purpose hydroelectric power development authorized by section 204 of the Flood Control Act of 1962, in accordance with the Army-Interior Agreement of March 14, 1962.³ The authorized project consists of the Long Lake and Crater Lake phases. The Long Lake phase was substantially completed by December 1, 1973. However, due to delays in providing reliable transmission service, full commercial power production did not commence until October 30, 1975. Additional construction on the Long Lake phase was performed during fiscal years 1976 and 1977. The Long Lake phase has plant capability of 168,000,000 kilowatt-hours of annual firm energy and continuous plant capacity of 47,160 kilowatts. The Crater Lake phase which is scheduled for completion in the late 1980's would provide an estimated 106,000,000 kilowatt-hours of additional annual firm energy. Plant capacity is currently estimated at 27,000 kilowatts.⁴

The existing rate of 15.6 mills per kilowatt-hour for energy from the Snettisham Project was adopted by the Department of Interior on December 1, 1973. This rate was premised on the requirements of the authorizing legislation, Pub. L. 87-874, that all costs were to be repaid within a reasonable period of time, which were generally considered to be 50 years. However, because of revenue losses associated with transmission line failures caused by extreme adverse weather conditions during prolonged periods, Congress granted special relief under subsection 201(b) of the Water Resources Development Act of 1976, Pub. L. 94-587, which

²Snettisham Project rates and charges were never subject to approval by this Commission's predecessor, the Federal Power Commission (FPC).

³Pursuant to the agreement between the Departments of the Army and Interior, the Corps of Engineers is responsible for project construction and the APA (now a part of DOE) is responsible for operation and maintenance.

⁴Although current power requirements for the Juneau area are supplied by the Snettisham Project and by facilities owned by the Alaska Electric Light and Power Company (AEL&P), the Snettisham Project is expected to accommodate all future load growth in the area. Due to the age of the AEL&P generating facilities, the project is expected to provide 97 percent of the area's requirements by 1990, with AEL&P supplying the remaining three percent.

¹The request was made pursuant to section 204 of the Flood Control Act of 1962, Pub. L. 87-874, 76 Stat. 1173, 1193, as amended by section 201(a) of the Water Resources Development Act of 1976, Pub. L. 94-587, section 302(a)(1) of the DOE Organization Act, Pub. L. 95-91, and by the DOE Secretarial Delegation Order No. 0204-33, effective January 1, 1979, 43 F.R. 60636 (December 28, 1978).

amended and restructured the repayment provisions for the project.⁵

The "Revised" Power Repayment Study (PRS) submitted with this filing continues the existing rate of 15.6 mills per kilowatt-hour, to establish the revenue level for the first ten years (development period) of the study. For the remaining 50 years of the authorized 60 year repayment period, the revenue level is based on the assumed rate of 26 mills per kilowatt-hour.

Discussion

As part of its analysis and approval of Federal rate filings, this Commission generally reviews the level of filed rates to determine if such rates, continued over the full repayment period, are sufficient to recover: (1) all power related project or system operation, maintenance, and marketing costs; (2) the cost of power purchases or exchanges and transmission services; (3) interest on the unamortized power investment financed from appropriated funds; and (4) amortization of (a) the power investment within 50 years after it becomes revenue producing or other such period as established by law, (b) the transmission investment within its service life (generally not to exceed 50 years), and (c) the investment in replacement costs for power facilities.

In the instant filing, however, the requirements of subsection 201(b) of Pub. L. 94-587 (the Act) result in a different rate for the development period than that required for the remaining 50 years of the authorized 60 year repayment period. Since the filed rate pertains only to the development period, we have identified the issues pertaining to the development period and formulated our conclusions with respect to the filed rate.

⁵Subsection 201(b) reads as follows:

(b) The Crater-Long Lakes division of the Snettisham Project near Juneau, Alaska, as authorized by Section 204 of the Flood Control Act of 1962, is modified with respect to the reimbursement payments to the United States on such project in order to provide (1) that the repayment period shall be sixty years, (2) that the first annual payment shall be 0.1 per centum of the total principal amount to be repaid, (3) thereafter annual payments shall be increased by 0.1 per centum of such total each year until the tenth year at which time the payment shall be 1 per centum of such total, and (4) subsequent annual payments for the remaining fifty years of the sixty-year repayment period shall be one-fiftieth of the balance remaining after the tenth annual payment (including interest over such sixty-year period).

Following are excerpts from the Senate Committee on Public Works' report on the legislation which further describes this provision of Pub. L. 94-587 and the principal reasons for the legislation:

The purpose of this subsection is to provide temporary relief to Juneau power users by altering the repayment schedule and amounts. Lower payments during the first ten years of the proposed sixty-year repayment period would be made possible by deferring the interest for this period. The total obligation (capital costs, plus interest) will still be met, as the interest deferred during the first ten years will be covered in the next fifty years. This temporary relief is necessary in view of the additional standby generating facilities which local interests had to install because of the numerous power outages experienced since 1972.

However, in order to provide guidance to the Assistant Secretary and APA for future filings, we also shall address certain outstanding issues associated with the repayment practices used by the Assistant Secretary and APA during the remaining 50 years of the authorized 60 year repayment period.

With respect to repayment procedures during the ten year development period, the Assistant Secretary uses a different repayment procedure than that specified in the Act.⁶ The PRS indicates that revenues, during the development period, are applied toward deferred interest costs incurred rather than to principal. The deferred interest costs are ultimately capitalized and repaid at the same interest rate (three percent) as the initial project investment as determined by the Secretary of the Treasury in accordance with criteria specified in the authorizing legislation. However, the procedure reflected in the PRS accompanying this filing does not have an effect on the revenue requirements. Thus, we do not believe that this departure from the methodology prescribed by the Act would justify disapproval of the filed rate.

Although continuation of the rate of 15.6 mills per kilowatt hour during the early portion of the development period will provide revenues somewhat higher than those that could be authorized under the Act, such revenues will be lower than they would have been absent the 1976 amendment. In addition, as noted in Rate Order APA-I, the APA proposal has "met with complete public acceptance." Thus, taken as a whole, we believe that extension of the existing rate will accomplish the intent of the Act which, as indicated by AS/RA, is to provide temporary relief to Juneau area customers.

With respect to the remaining 50 years of the 60 year repayment period, we note various discrepancies in the repayment procedures used by the Assistant Secretary and APA. These discrepancies are as follows:

A. In accordance with previous procedures followed by the FPC, and in accordance with the Assistant Secretary's own regulations, commencement of the repayment period is related to the date on which a project commences commercial operation, in this case 1975. APA apparently assumes that the repayment period does not begin until the last major investment is made, in this case 1978. Consequently, the PRS shows project repayment over a 63-year period. The Act specifically states, "(1) that the repayment period shall be sixty years...." Therefore, the Commission believes that repayment should be accomplished within 60 rather than 63 years.

⁶The Act states:

...(2) that the first annual payment shall be 0.1 per centum of total principal amount to be repaid, (3) thereafter annual payments shall be increased by 0.1 per centum of such total each year until the tenth year at which time the payment shall be 1 per centum of such total,....

B. We note with continuing concern the policy of repaying the highest interest-bearing investment first while deferring amortization of low interest-bearing investments to a later time within the repayment period. We have previously expressed our concern on this subject.⁷ If the APA were to repay capital investments based on generally accepted amortization methods as recognized by this Commission, annual revenue requirements during the 50-year period would have to be greater than those indicated in the PRS submitted with this filing.

C. As a result of the policy of repaying the highest interest-bearing investment first, the PRS indicates that the accelerated repayment of replacements, rather than continuous amortization of the initial investment, would result, during the 60th year of repayment, in an unpaid balance of the initial investment which would exceed the allowable unpaid balance. To satisfy this deficiency, the PRS shows a transfer of \$5,823,408 from the unpaid power investment balance to the unpaid replacement balance. Since the unpaid power investment is transferred to the unpaid replacement account, it is treated as a replacement investment and repaid in subsequent years when revenues are adequate. This transfer of funds or transfer of obligations is considered "borrowing" by APA and the Assistant Secretary. Since replacements have been repaid at an accelerated rate, APA assumes that it can transfer or borrow funds from the replacement account to meet obligations which are behind schedule in the power investment account. The Commission considers this practice to be erroneous. The repayment study should be structured so as to provide for the repayment of each investment within its specified repayment period, independent of replacements made during such period. We believe that it is improper to "borrow" from an already repaid investment or replacement account in order to offset excesses of the unamortized balance in other accounts. The investments and replacements do not represent allocated and/or appropriated funds to be drawn upon once such amounts are repaid to the Department of the Treasury, prior to the end of the repayment period, without an authorization from Treasury. Such transfers, if authorized, would in effect create a new investment account and not a continuation of an existing, previously authorized investment account.

D. The Act requires that outstanding principal balances as of the end of the development period be amortized, by a specified formula, during the following 50-year period. This formula is actually a straight-line amortization method, which requires a constant annual principal payment with declining annual interest payments as the principal balance is reduced. As noted in the PRS, APA has adopted a compound interest method for amortizing principal balances on this project. This method requires uniform annual payments consist-

ing of principal and interest. We believe that the adopted amortization method does not comport with the provisions of the Act, although it does follow procedures generally used in repaying Federal power investments. Over the life of the repayment period, the total rate impact resulting from two different amortization methods should be the same. However, the straight-line amortization method would produce higher rates in the early years of the fifty-year period and lower rates as principal balances are reduced in subsequent years.

E. We note also a number of discrepancies in the PRS for handling future replacements, as follows:

(1) Rate Order No. APA-1, dated March 9, 1979, and a letter to the Commission from the Assistant Secretary dated December 26, 1979, both state that the interest rate on future replacements on the Snettisham Project is to be seven percent. However, the PRS submitted with this filing uses an interest rate of six percent in all interest calculations associated with future replacements. In accordance with a policy established by the Secretary of Interior, the interest rate applicable for repayment of most Federally constructed water resource projects is determined by the Secretary of the Treasury, as of the beginning of each fiscal year, on the basis of the computed average interest rate payable by the Treasury on its outstanding marketable public obligations, which are neither due nor callable for redemption for fifteen years from the date of issue. The interest rate applicable to future replacements is based on the current year's interest rate, as reflected in the latest PRS. This policy, which was agreed upon by the Department of the Army, the Department of Interior, and the FPC, continues to be accepted by the Assistant Secretary and appears appropriate for the purposes of this Commission. This policy is contained in the Department of Energy Order RA 6120.2. Under these criteria, the appropriate interest rate for replacements for this project is seven percent.

2. Another policy which was followed by the three agencies, and which was included in section 10(j) of the Department of Energy Order RA 6120.2, is stated as follows:

Interest Expense. Interest expense for each of the years of the study will be the sum of the amounts determined by: (1) applying the applicable interest rate to each estimated unamortized power investment at the beginning of the year; plus (2) applying one-half the applicable interest rate to power investments (i.e., additions and replacements) expected to be added in service during the year; plus (3) applying the applicable interest rate to capitalized unpaid or deferred annual expense, if any.

We note that for most of the years during the 50-year period, the one-half year's interest expense, as specified in RA 6120.2, was not computed for the year a replacement was to be placed in service. In addition, after the replacement is placed in service, the

⁷See, e.g., *Southwestern Power Administration*, Docket No. EF79-3052, order issued October 25, 1979.

PRS shows inconsistent interest expense computations. For some years in the PRS, interest expenses on unpaid replacements appear to be based on one-half year's interest while, in other years, no interest amounts on unpaid replacements were charged as an expense. We estimate that if interest on replacements had been computed in accordance with RA 6120.2 procedures, the total revenue level for interest expense on replacements for the 50-year period would have to be increased by approximately \$1,300,000.

Conclusions

According to our analysis, if the discrepancies noted above were corrected, the rate of 26 mills per kilowatt-hour would not result in project repayment within the period required by the Act. However, these matters have no effect on rates during the period for which the Assistant Secretary seeks approval in the instant docket, i.e., April 1, 1979 through November 30, 1983.

For the reasons stated above, the Commission finds that the Schedule SN-F-1 rate of 15.6 mills per kilowatt hour for energy, applicable to the Snettisham Project ten-year development period and proposed for the period April 1, 1979 through November 30, 1983, is consistent with the public interest. Therefore, we shall confirm and approve the rate. However, this confirmation of the proposed rate level for the period specified is not to be construed as approval of the specific practices or methodologies reflected in APA's "Revised" Power Repayment Study.

The Commission orders:

(A) The Schedule SN-F-1 rate of 15.6 mills per kilowatt hour proposed for the period April 1, 1979, through November 30, 1983, as submitted by the Assistant Secretary for Resource Applications, is hereby confirmed and approved.

(B) The Secretary shall promptly publish this order in the Federal Register.

By the Commission.

(SEAL)

Kenneth F. Plumb,
Secretary

UNITED STATES OF AMERICA FEDERAL ENERGY REGULATORY COMMISSION

ELECTRIC RATES: Confirmation Of Federal Rates

Before Commissioners: Charles B. Curtis, Chairman;
Matthew Holden, Jr., George
R. Hall and J. David Hughes.

Southwestern Power) Docket No. EF79-4051
Administration)

ORDER CONFIRMING AND APPROVING TRANSMISSION RATES (Issued December 2, 1980)

By letter filed June 25, 1979, the Assistant Secretary for Resource Applications (AS/RA) of the Department of Energy, on behalf of the Southwestern Power Administration (SWPA), submitted a request for final approval of an interim extension of transmission rate schedule TDC (revised) for the period July 1, 1979 through June 30, 1980. On July 1, 1980, AS/RA amended the request with an implied expiration date of December 31, 1980. TDC (revised) is a rate schedule applicable to transmission and/or displacement of non-federal power and energy over the SWPA system. By Rate Order No. SWPA-3, AS/RA confirmed and approved on an interim basis the extension of rate schedule TDC (revised), effective July 1, 1979, for the period ending June 30, 1980. By Rate Order No. SWPA-6, AS/RA extended rate schedule TDC (revised) through December 31, 1980.¹

Public notice of the June 25, 1979 submittal was published in the Federal Register on July 11, 1979. On October 1, 1980, notice of both the June 25, 1979, and July 1, 1980 filings of AS/RA was published, with protests or petitions to intervene due on or before October 14, 1980. No responses have been received.

SWPA is a federal power marketing agency comprised of 20 multipurpose reservoir projects located in portions of Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas. The projects represent a total hydroelectric capacity of 1,999,200 kilowatts. The SWPA transmission system consists of 1,402 miles of 138 and 161 KV transmission lines, 234 miles of 69 KV transmission lines, and 31 bulk power substations and switching stations. Non-federal power and energy is transmitted over portions of the system if the SWPA Administrator determines that transmission and transformation capacity are available in excess of that needed for marketing power from the federal generating plants. Currently, thirteen customers are billed for the transmission of non-federal power under rate schedule TDC (revised).²

Discussion

Prior to the Department of Energy Organization Act (1974) [1977-Ed.], SWPA transmission rates were not submitted to the Federal Power Commission for

¹The extensions of rate schedule TDC (revised) have been submitted to the Commission for final confirmation and approval.

²The customers are Ark-Mo Power Company, Grand River Dam Authority, Public Service Company of Oklahoma, Associated Electric Cooperative, Western Farmers Electric Cooperative, the Cities of Jonesboro, Paragould, and Piggott, Arkansas, and the Cities of Carthage, Kennett, New Madrid, Poplar Bluff, and Sikeston, Missouri,

The Commission finds it to be appropriate and in the public interest to approve and confirm the requested rate extension. The rates to be charged during the additional time period were previously approved by the FPC, and such extension will allow the rates to be consistent with the terms of the SWPA-Tex-La contract. As set out in AS/RA Rate Order No. SWPA-5, the additional time will "allow time to develop studies necessary for review of the present power rate and to undertake a public participation process in the event the rate requires adjustment."

These considerations, as well as the relatively short duration of the rate schedule and the lack of any protests to the rates, lead us to conclude that the proposed rates should be confirmed and approved.

The Commission orders:

(A) The extension of rates charged by SWPA from the Narrow Dam Project for the period July 1, 1980 through August 2, 1981, as submitted by AS/RA on behalf of SWPA, is hereby confirmed and approved.

(B) The Secretary shall promptly publish this order in the Federal Register.

By the Commission.

(SEAL)

Kenneth F. Plumb,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY
COMMISSION

Before Commissioners: Georgiana Sheldon, Acting
Chairman; Matthew Holden,
Jr., and George R. Hall.

Southwestern Power Administration) Docket No.
EF79-4021

ORDER CONFIRMING AND APPROVING
LONG-TERM RATES
(Issued January 8, 1981)

On April 12, 1979, the Assistant Secretary for Resource Applications (RA) of the Department of Energy tendered for filing, on behalf of the Southwestern Power Administration (SWPA), a request for confirmation and approval of rates and charges for the sale of all hydroelectric power generated at the Corps of Engineers' Sam Rayburn Dam project to Sam Rayburn Dam Electric Cooperative, Inc. (Cooperative).¹ These

¹The referral was made pursuant to the provisions of Section 5 of the Flood Control Act of 1944, Section 302(a)(1) of the DOE Organization Act, and Section 2 of DOE Secretarial Delegation Order No. 0204-33.

rates, which would remain effective until May 31, 1984, were approved by RA Rate Order No. SWPA-2, issued June 1, 1979, on an interim basis. The proposed rates would produce a 35% increase in annual revenues from \$1,030,000 to \$1,388,300.

The Sam Rayburn Dam project, located on the Angelina River in the Neches River basin in eastern Texas, consists of two hydroelectric generating units with an installed capacity of 52,000 kW. The project is not interconnected with SWPA's integrated electric system. Instead, the power produced by the Sam Rayburn Dam project is marketed by SWPA as an isolated project.

Public notice of the instant submittal was published in the Federal Register on May 4, 1979, with comments required to be filed by interested persons on or before May 18, 1979. A petition to intervene was filed by Cooperative on May 22, 1979. By letter dated January 23, 1980, Cooperative was provided a further opportunity to formulate and submit comments on the proposed rate increase. On March 12, 1980, Cooperative filed additional comments. Cooperative's pleading raises several issues and also seeks to incorporate in this proceeding positions that it previously advanced in Docket No. E-7201.² Cooperative asserts, *inter alia*, that SWPA has improperly included costs for future replacements in the proposed rates, improperly allocated administrative and overhead expenses, and improperly estimated O&M expenses. In addition, Cooperative maintains that SWPA has not justified the proposed rates on the basis of a "cost of service" study, and Cooperative requests that an evidentiary hearing be initiated to determine the proper rates for SWPA in this proceedings.

Discussion

As an initial matter, we find that participation by Cooperative in this proceeding may be in the public interest. We shall therefore grant the petition to intervene.

Cooperative's contention that SWPA's rates must be developed on a cost of service basis is mistaken. The United States Court of Appeals for the District of Columbia Circuit, in *Sam Rayburn Dam Electric Cooperative, et al., v. Andrus, et al.*, Civil No. 1219-71

²According to Cooperative, this pleading is intended to supplement the pleading that it filed in Docket No. E-7201. On September 30, 1976, in Docket No. E-7201, the Secretary of the Interior tendered for filing with the Federal Power Commission an application for confirmation and approval of rates providing for annual revenues of \$1,152,900. On October 1, 1977, the DOE Organization Act caused this case to be transferred to the Economic Regulatory Administration, of the Department of Energy (ERA). By order issued May 26, 1978, ERA determined that the proposed rates of \$1,152,900 were inadequate to recover the project costs within a reasonable time and denied the request for increased rates.

(1978),³ rejected a similar claim that a full cost of service approach to ratemaking is mandated in proceedings under Section 5 of the Flood Control Act of 1944. The court concluded that reliance on SWPA's rate and replacement method was reasonable and consistent with the Act. Similarly, in this proceeding, the repayment study submitted with the filing has provided the Commission with sufficient information to examine the proposed rates under the standards imposed by the Flood Control Act.

According to Cooperative, the proposed rate increase is premised on various facts which are in dispute and thus an evidentiary hearing is required. We disagree. No formal hearing is necessary in this case. *Associated Electric Power Cooperative v. Morton*, 507 F.2d 1167 (D.C. Cir. 1974). See *Vermont Yankee Nuclear Power Corp. v. NRDC*, 435 U.S. 519 (1978). Cooperative, the only contractual customer for the hydroelectric power generated at the Corps of Engineers' Sam Rayburn Dam Project, was fully apprised of the proposed rate increase and of its right to submit written comments thereon. Moreover, the Cooperative's opportunity to comment on the rate increase fully satisfied due process requirements. *Associated Electric Power Cooperative v. Morton*, *supra*. See *United States v. Florida East Coast Railway Co.*, 410 U.S. 224 (1973). The mere presence of technical issues in and of itself is insufficient to support a requirement for evidentiary hearings. See *O'Donnell v. Shaffer*, 491 F.2d 59 (D.C. Cir. 1974).

SWPA's rates are before this Commission pursuant to the authority of the Flood Control Act of 1944, 16 U.S.C. §825s, the Department of Energy Organization Act, P.L. 95-91, August 4, 1977 as amended, and the Secretary of Energy's Delegation Order No. 0204-33. Unlike rate applications made by a private utility under the Federal Power Act where the "just and reasonable" test is to be applied, the instant proceeding is governed by Section 5 of the Flood Control Act of 1944. The standards have been prescribed by Congress. Such rate schedules must be drawn:

1. Having regard to the recovery of the cost of generation and transmission of such electric energy;
2. So as to encourage the most widespread use of SWPA power;
3. To provide the lowest possible rates to consumers consistent with sound business principles; and
4. In a manner which protects the interests of the United States in amortizing its investment in the projects within a reasonable period.

The rate schedules so evolved become finally effective only upon confirmation and approval by the Commission. As a result, the Commission's authority to review such rate schedules is limited. The Commission

views its role in this matter as similar to that of an appellate court. In this capacity, the Commission can affirm, reject or remand the rates submitted to it for confirmation and approval. Under the statute, the Commission must initially determine whether the rate schedules would provide a sufficient level of revenues to allow SWPA to recover its capital costs. The Commission's review of this matter is based on the supporting data and information submitted by the RA as well as the comments filed by the Cooperative. Based upon this information, the Commission can review the rates to determine whether the interests of the United States in amortizing investment in the Sam Rayburn Dam project within a reasonable period are protected, and whether the rate scheme encourages the widest use of SWPA power and provides the lowest rates to consumers consistent with sound business principles.

Our review of the supporting documents reveals that the proposed rates are consistent with the statutory requirements. Accordingly, we shall confirm and approve those rates. This confirmation of the proposed rate schedules should not be construed as approval of the specific practices or methodologies reflected in SWPA's repayment study.⁴

The Commission orders:

(A) The long-term rates for the sale of hydroelectric power and energy generated at the Corps of Engineers' Sam Rayburn Dam project, as submitted by the Assistant Secretary for Resource Applications of the United States Department of Energy, are hereby confirmed and approved.

(B) The Cooperative is hereby permitted to intervene in this proceeding subject to the Rules and Regulations of the Commission; *provided, however*, that the participation by this intervenor shall be limited to matters set forth in its petition to intervene; and *provided, further*, that the admission of this intervenor shall not be construed as recognition by the Commission that it might be aggrieved because of any order or orders entered by the Commission in this proceeding.

(C) The Cooperative's request that we establish hearing procedures concerning the Sam Rayburn Dam project rates is hereby denied.

(D) The Secretary shall promptly publish this order in the Federal Register.

By the Commission.

Kenneth F. Plumb,
Secretary.

⁴The Commission notes some concern with such practices as SWPA's repayment of the highest interest bearing investment first and SWPA's allocation of its administrative and overhead expenses on the basis of plant investment. However, we do not reach these questions in the exercise of our confirmation authority in this proceeding inasmuch as the combined effect of these practices on the revenue requirements shown in SWPA's study is relatively small.

³This is an unreported opinion.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY
COMMISSION

ELECTRIC RATES: Confirmation of Federal Rates

Before Commissioners: Georgiana Sheldon, Acting
Chairman; Matthew Holden,
Jr., George R. Hall and J.
David Hughes.

Southeastern Power Administration) Docket No.
EF80-3041

ORDER CONFIRMING AND APPROVING RATE
SCHEDULES

(Issued January 29, 1981)

By letter filed April 25, 1980, the Assistant Secretary for Resource Applications (AS/RA) of the Department of Energy, on behalf of the Southeastern Power Administration (SEPA), submitted a request for final confirmation and approval of an interim extension of wholesale power rate schedules KP-1-B, KP-2-B, and JHK-1-B for the period July 1, 1980, through September 30, 1981.¹ These rate schedules apply to power marketed by SEPA from the Corps of Engineers' multi-purpose reservoir projects known as the John H. Kerr and Philpott projects. By Rate Order No. SWPA-7, dated April 22, 1980, the AS/RA confirmed and approved the rates on an interim basis.

Notice of this submittal was published in the Federal Register on May 8, 1980, with protests or petitions to intervene due on or before June 2, 1980. No responses have been received.

SEPA is a federal power marketing agency responsible for a number of reservoir projects, including the integrated Kerr-Philpott projects in Southern Virginia.² The total installed hydroelectric capacity of the projects is 218,000 kilowatts. SEPA owns no transmission facilities, relying, instead, upon the facilities of Virginia Electric and Power Company (VEPCO) and Carolina Power & Light Company (CP&L) to transmit power to its preference customers.

Long-term contracts for the sale of power, which became effective April 1, 1973, were negotiated with CP&L, and with 16 customers served by its transmission facilities. In addition, other long-term agreements for the sale of power, which became effective June 30, 1973, were negotiated with VEPCO and with 17 customers served through that company's transmission facilities. All of these contracts expired on June 30, 1980.

¹This referral was made pursuant to Department of Energy Secretarial Delegation Order No. 0204-33, and the pertinent provisions of the Flood Control Act of 1944.

²The Kerr and Philpott projects are located on the Roanoke River and Smith River, respectively.

The Philpott project is located within the service area of Appalachian Power Company (APPCO). Thus, in order for the Kerr and Philpott projects to operate on an integrated basis, SEPA's agreement with VEPCO provides that APPCO will accept the entire output of the Philpott project into its system for the account of VEPCO which, in turn, receives an equivalent amount of power from APPCO at points of interconnection between the two companies. In effect, SEPA markets the power from Philpott as if it were generated at the Kerr project.

Rate schedule KP-1-B is applicable to public bodies and cooperatives which operate within 150 miles of the Kerr project and receive power through VEPCO's transmission facilities. Rate schedule JHK-1-B governs sales to public bodies and cooperatives operating within 165 miles of the interconnection point for the VEPCO and CP&L systems and which are served by CP&L's transmission facilities. Rate schedule KP-2-B is applicable to power and energy sold to CP&L and VEPCO under contracts between them and SEPA.

Discussion

The Secretary of Energy, in Delegation Order No. 0204-33, delegated to this Commission the authority to confirm and approve on a final basis, or to disapprove, federal power marketing agency rates. In accordance with the standards established in section 5 of the Flood Control Act of 1944, the rates are to "encourage the most widespread use [of project power and energy] at the lowest possible rates to consumers consistent with sound business principles," and to recover "the cost of producing and transmitting such electric energy, including the amortization of the capital investment allocated to power over a reasonable period of years."³

The rate schedules which are the subject of this order were approved by the Federal Power Commission in Docket No. E-7002, on February 18, 1976, for the period ending June 30, 1980. According to AS/RA, the interim extension has been requested in order to enable SEPA to develop a new written power marketing policy for the Kerr-Philpott projects and to negotiate superseding contracts consistent with the new policy. Upon completion of these events, the AS/RA states that a new rate approval presentation will be submitted to the Commission, together with a repayment study and other supporting materials. With respect to the currently effective rates, the AS/RA indicates that 1975 through 1979 expenses associated with the Kerr-Philpott projects were lower than had been estimated, thereby resulting in greater amortization of the capital investment than was anticipated when these SEPA rates were previously approved. The AS/RA has further stated that operating expenses for 1980 and 1981 are projected to essentially equal O&M estimates used for the 1975 through 1979

³16 U.S.C. 825s.

period and, therefore, the existing rates can be expected to produce revenues during the interim extension period adequate to repay costs associated with the production and transmission of power at the projects.

In light of the foregoing facts and the lack of any protests or petitions to intervene in the present proceeding, the Commission finds it appropriate and in the public interest to approve and confirm the extension of rate schedules KP-1-B, KP-2-B, and JHK-1-B for the period July 1, 1980, through September 30, 1981.

The Commission orders:

(A) The interim extension of rate schedules KP-1-B, KP-2-B, and JHK-1-B for the period July 1, 1980 through September 30, 1981, is hereby confirmed and approved.

(B) The Secretary shall promptly publish this order in the Federal Register.

By the Commission.
(SEAL)

Lois D. Cashell,
Acting Secretary

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY
COMMISSION
ELECTRIC RATES
Confirmation of Federal Rates

Before Commissioners: Georgiana Sheldon, Acting
Chairman; George R. Hall and
J. David Hughes.

Southeastern Power Administration) Docket No.
EF79-3021

ORDER CONFIRMING AND APPROVING RATE
SCHEDULES
(Issued February 27, 1981)

By letter filed May 22, 1979, the Assistant Secretary for Resource Applications (AS/RA) of the Department of Energy, on behalf of the Southeastern Power Administration (SEPA), submitted a request for final confirmation and approval of wholesale power rate schedules CR-1-D and CR-2-D for the period ending June 30, 1983.¹ These rate schedules supersede schedules previously confirmed and approved by the Federal Power Commission through June 30, 1978, and apply to power marketed by SEPA from the U.S. Corps of Engineers' multi-purpose reservoir projects known as the Cumberland Basin projects. By Rate Order No. SEPA-4, dated May 22, 1979, the AS/RA approved the rates on an interim basis for the period July 1, 1978, through June 30, 1980. On May 22, 1980, the AS/RA extended the interim approval through June 30, 1981.

¹This referral was made pursuant to Department of Energy Secretarial Delegation Order No. 0204-33 and the pertinent provisions of the Flood Control Act of 1944.

Notice of this submittal was published in the Federal Register on June 20, 1979, with protests or petitions to intervene due on or before July 9, 1979. No responses have been received.

SEPA is a federal power marketing agency responsible for a number of reservoir projects, including the integrated Cumberland Basin projects in Tennessee and Kentucky.² These projects have a combined nameplate capacity of 853,000 kilowatts and produce an average of 2,920,000,000 kilowatt-hours annually.

Power and energy from these projects are sold to the Tennessee Valley Authority (TVA) under rate schedule CR-1-D, and retained peaking, standby, and emergency Standby power and energy are sold to four other customers,³ under rate schedule CR-2-D. The new rates will produce an estimated average annual revenue of \$18,650,000, representing an increase of \$2,538,000 (16%) over the previously approved rates.

Discussion

The Secretary of Energy, in Delegation Order No. 0204-33, delegated to this Commission the authority to confirm and approve on a final basis, or to disapprove, federal power marketing agency rates. In accordance with the standards established in section 5 of the Flood Control Act of 1944, the rates are to "encourage the most widespread use [of project power and energy] at the lowest possible rates to consumers consistent with sound business principles" and to recover "the cost of producing and transmitting such electric energy, including the amortization of the capital investment allocated to power over a reasonable period of years."⁴

The Corps of Engineers has allocated \$336,775,000 of capital investment to be repaid by fiscal year 1982, including approximately \$68,000,000 for remedial work being performed on one of the eight SEPA facilities, the Wolf Creek Project. As a result of increased costs, especially those attributable to the remedial work at Wolf Creek, SEPA entered into supplemental agreements with TVA and the other customers in May of 1978, providing, in part, that the filed rates would be effective as of July 1, 1978. These rates superseded prior rate schedules confirmed and approved by the Federal Power Commission in Docket No. E-7188, on June 29, 1973, for the period July 1, 1973, through June 30, 1978.

²The Cumberland Basin projects comprise eight federally constructed hydroelectric generating projects located on the Cumberland River and its tributaries.

³The other customers are: Big Rivers Electric Corporation; the Indiana Statewide Rural Electric Cooperative; the Southern Illinois Power Cooperative; and the East Kentucky Power Cooperative.

⁴16 U.S.C. 825s.

On June 2, 1978, the AS/RA filed a request for confirmation and approval of the new rate schedules with the Department of Energy's Economic Regulatory Administration (ERA). By order issued on December 29, 1978, (44 FR 1444) the Administrator of ERA disapproved the filed rates on the basis that they were higher than necessary to recover the costs of producing and transmitting the power and energy sold by the projects. In April of 1979, SEPA prepared a revised Power Repayment Study (PRS) which changed certain repayment criteria used in previous studies and used historical rather than estimated financial data for fiscal year 1978. SEPA concluded that the results of the revised PRS supported the same revenue level as that which has been proposed in ERA Docket No. SEPA 78-2. On May 22, 1979, the AS/RA approved the rates on an interim basis, from July 1, 1978, through June 30, 1980, pending final confirmation and approval by this Commission. On May 22, 1980, the AS/RA extended the interim approval through June 30, 1981.

The filed rate schedules in this docket are the same as those previously filed with ERA and rejected; however, the changes in criteria have eliminated the excess revenues that formed the basis for the prior ERA rejection.

SEPA's PRS indicates that, based on estimates of average annual revenues of \$18,650,000 and annual operating expenses of \$5,450,000, the investment allocated to power, including all but \$6,273,000 of the replacement costs, will be repaid by the end of fiscal year 2024 (the 50th year after the last completed project began commercial operation). Supporting data to the PRS indicate that the unpaid \$6,273,000 are costs of replacements whose service lives extend beyond the initial project repayment period.

The amount of the unpaid balance on replacement items appears to be reasonable. However, our analysis of the data supporting the instant filing, as well as filings by other federal power marketing agencies before this Commission, reveals certain concerns, including inconsistencies in calculating operation and maintenance expenses and future replacement costs. There appears to be no firm AS/RA policy with respect to determining the price levels to be used for estimating these costs. In addition, we note that SEPA has failed in this filing to assess interest expense on investments in new project additions and replacements for the year in which they commence service, contrary to the policy adopted by the Department of Energy, in Order No. RA 6120.2, issued in September of 1979. We believe it appropriate to express these observations although they do not have a sufficient rate level impact to warrant rejection of the filed rates. Furthermore, we recognize that the AS/RA has initiated efforts to further clarify the policies incorporated in Order No. RA 6120.2.⁵

⁵On January 16, 1981, the AS/RA ratified four general recommendations sponsored by the Director of DOE's Office of Power Marketing

According to SEPA's PRS, repayment of each major investment allocated to power is to be accomplished within the service life of the investment or 50 years, whichever is less. In the study, SEPA applied the long-standing policy, initially developed by the Department of Interior and continued by the AS/RA, of repaying selected high interest investments ahead of the required repayment date and postponing repayment of lower interest investments. By pursuing this policy, the overall system-wide interest expense paid to the Treasury is minimized in an effort to keep rates at the lowest possible levels. While the Commission has previously expressed concern with regard to this matter,⁶ the AS/RA has recently affirmed the position that the existing practice should not be changed at this time.⁷

This payment policy has been in effect for approximately eight years, during which time the Federal Power Commission frequently approved federal rate filings. Further, rates based on this policy reflect actual current payments being made to the U.S. Treasury. We note that, to date, the Treasury and the Office of Management and Budget have neither protested the current practice nor proposed an alternative repayment policy reflecting higher interest payments. Despite the Commission's stated concern regarding this repayment methodology, in exercising our appellate review function, we are not prepared to conclude at this time that the AS/RA policy lacks a rational basis.

In light of the foregoing and the lack of any protests or petitions to intervene in the present proceeding, the Commission finds it appropriate and in the public interest to approve and confirm SEPA rate schedules CR-1-D and CR-2-D for the period July 1, 1978, through June 30, 1983.

The Commission orders:

(A) SEPA rate schedules CR-1-D and CR-2-D are hereby confirmed and approved for the period July 1, 1978, through June 30, 1983.

Coordination (OPMC) on the basis of a Power Rate Council Amortization Issue Paper. Two recommendations pertinent to this order included: (1) a proposal to continue at this time the existing repayment policy of assigning revenues to the highest interest-bearing investments first, while staying within allowable repayment periods (unless otherwise indicated by legislation); and (2) a proposal for the OPMC, together with the power marketing agencies, to develop guidelines or refine policies in DOE Order No. RA 6120.2, so that applicable policies will be current and will not be, or appear to be, implemented in a manner that discredits them. In soliciting AS/RA approval of these recommendations, the OPMC Director noted that "[t]he recommendations are based on the conclusions that existing repayment practices are basically sound but need to be improved, both substantively and in their implementation."

⁶E.g., *Southeastern Power Administration*, Docket No. EF79-3052, order issued October 25, 1979.

⁷See footnote 5, *supra*.

(B) The Secretary shall promptly publish this order in the Federal Register,

by the Commission.

(SEAL)

Kenneth F. Plumb,
Secretary

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY
COMMISSION

ELECTRIC RATES: Federal Rates

Before Commissioners: Georgiana Sheldon, Acting
Chairman; Matthew Holden,
Jr., George R. Hall and J.
David Hughes.

Southeastern Power Administration) Docket No. EF79-3011

ORDER CONFIRMING AND APPROVING
FEDERAL RATES
(Issued April 3, 1981)

On August 3, 1979, the Assistant Secretary for Resource Applications (AS/RA) of the Department of Energy filed a request for confirmation and approval of rate schedules concerning the sale of hydroelectric power marketed by the Southeastern Power Administration (SEPA) from nine Corps of Engineers multiple-purpose reservoir projects known as the Georgia-Alabama Projects.¹ Approval is requested for the period beginning October 1, 1979, when the rate schedules were placed in effect on an interim basis, and ending on September 30, 1983. The rate schedules provide for an increase in annual power revenues from \$27,862,000 to \$31,483,000. This represents an increase of approximately 13 percent above annual power revenues associated with the previous rates which were in effect since November 29, 1976. The increased rates will provide an average revenue level of approximately 10.5 mills per kWh.

Notice of the filing in this docket was published in the Federal Register on August 20, 1979. Interested persons were invited to submit written comments to the Commission on or before September 7, 1979. No comments or petitions to intervene were received.

Discussion

SEPA's rates are before this Commission pursuant to the authority of the Flood Control Act of 1944, 16 U.S.C. §825s, the Department of Energy Organization Act, P.L. 95-91, August 4, 1977, as amended, and DOE Secretarial Delegation Order No. 0204-33, issued December 21, 1978. The applicable standards have been prescribed by Congress in section 5 of the Flood Control Act of 1944. Such rate schedules must be drawn:

1. having regard to the recovery of the cost of generation and transmission of such electric energy;
2. so as to encourage the most widespread use of project power;
3. to provide the lowest possible rates to consumers consistent with sound business principles; and
4. in a manner which protects the interests of the United States in amortizing its investment in the projects within a reasonable period.

The rate schedules so evolved become finally effective only upon confirmation and approval by the Commission. As stated in prior orders,² the Commission views its role in reviewing such rate schedules as similar to that of an appellate court. In this capacity, the Commission can affirm, reject or remand the rates submitted to it for confirmation and approval. The Commission's review is based on the supporting data and information submitted, including the Power Repayment Study (PRS) prepared by SEPA.

SEPA's PRS indicates that all applicable costs, including investments made in replacement items with service lives extending beyond the repayment period,³ will be repaid by the end of fiscal year 2027 (the 50th year after the last project began commercial operation). While we have previously questioned certain of the practices reflected in SEPA's repayment studies,⁴ our

²E.G., *Southeastern Power Administration*, Docket No. EF79-3021, order issued February 27, 1981; *Bonneville Power Administration*, Docket No. EF80-2011, order issued November 21, 1980.

³We note that it is contrary to general practice to recover during the repayment period replacement costs associated with items that have service lives continuing beyond the repayment period. However, the revenue impact of SEPA's treatment of such items is nominal for the period in question and, therefore, would not warrant rejection of the tendered rates.

⁴For example, in Docket No. EF79-3021 (order issued February 27, 1981), we expressed concern regarding (1) inconsistencies in calculating operation and maintenance expenses and future replacement costs, (2) failure to assets interest expense for new project additions and replacements for the year in which they commence service (see DOE Order No. RA 6120.2, issued September 1979), and (3) the practice of repaying selected high-interest investments ahead of the required repayment date and postponing repayment of lower-interest investments. With respect to the latter point, we noted that "[d]espite the Commission's stated concern regarding this repayment methodology, in exercising our appellate type review function, we are not prepared to conclude at this time that the AS/RA policy lacks a rational basis."

¹The filed rate schedules (GAMF-1-B, GAMF-2-B, ALA-1-B, MISS-1-B, SC-1-B, SC-2-B, CAR-1-B, and CAR-2-B), are applicable to wholesale customers located in the service areas of Duke Power Company, South Carolina Public Service Authority, Georgia Power Company, Alabama Power Company, Mississippi Power Company, and Gulf Power Company.

review of those matters in the instant docket demonstrates an insignificant revenue effect which does not serve as a basis for disapproval of SEPA's rates. According to the PRS, at the end of the repayment period SEPA will have a total accrued surplus which amounts to about 1.5 percent of the projects' total annual revenue requirements. This surplus is considered reasonable under the circumstances of this filing. We find the proposed rates to be consistent with the statutory requirements. Accordingly, we shall confirm and approve those rates. However, this confirmation of the proposed rate schedules should not be construed as approval of the specific practices or methodologies in SEPA's repayment study.

The Commission orders:

(A) The rate schedules identified in footnote 1 and applicable to the sale of hydroelectric power and energy generated at the Corps of Engineers' Georgia-Alabama Projects, as submitted on August 3, 1979, in this docket, are hereby confirmed and approved for the period extending from October 1, 1979, through September 30, 1983.

(B) The Secretary shall promptly publish this order in the Federal Register.

By the Commission.

(SEAL)

Lois D. Cashell,
Acting Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY
COMMISSION

ELECTRIC RATES: Federal Rates

Before Commissioners: Georgiana Sheldon, Acting
Chairman; Matthew Holden,
Jr., George R. Hall and J.
David Hughes.

Southeastern Power) Docket No. EF80-3031
Administration)

ORDER CONFIRMING AND APPROVING
FEDERAL RATES
(Issued April 9, 1981)

On December 7, 1979, the Assistant Secretary for Resource Applications (AS/RA)¹ of the Department of Energy filed a request for confirmation and approval of rate schedules JW-1(Revised) and JW-2-B which apply to hydroelectric power marketed by the South-

eastern Power Administration (SEPA) from one of the U.S. Corps of Engineers' multi-purpose reservoir projects known as the Jim Woodruff project.² Approval is requested for the period beginning October 20, 1979 when the rates were placed in effect on an interim basis by the AS/RA, and ending on August 19, 1982. The revised rates will result in a decrease in annual revenues from \$2,338,000 to \$2,030,000 or about 13 percent. Average system energy costs will be reduced from 9.35 mills per KWh to 8.12 mills per KWh.

Notice of the filing in this docket was published in the Federal Register on December 27, 1979, with comments due on or before January 30, 1980. No comments or petitions to intervene were received.

Discussion

The Secretary of Energy, in Delegation Order No. 0204-33, delegated to this Commission the authority to confirm and approve on a final basis, or to disapprove federal power marketing agency rates. In accordance with the standards established in section 5 of the Flood Control Act of 1944, the rates are to "encourage the most widespread use [of project power and energy] at the lowest possible rates to consumers consistent with sound business principles" and to recover "the cost of producing and transmitting such electric energy, including the amortization of the capital investment allocated to power over a reasonable period of years."³

As stated in prior orders,⁴ the Commission views its role in reviewing such rates as similar to that of an appellate court. In this capacity, the Commission can affirm, reject or remand the rates submitted to it for confirmation and approval. The Commission's review is based on the supporting data and information submitted, including the Power Repayment Study (PRS) prepared by SEPA.

On July 11, 1977, the Department of the Interior, on behalf of SEPA, filed a request with the Federal Power Commission for approval of an extension of the existing preference customers' rate schedule and approval of a revised schedule applicable to Florida Power Corporation, based on an April 1977 PRS. The filing subsequently was transferred to the Department of Energy's Economic Regulatory Administration (ERA).⁵ On

²The Jim Woodruff project is located in the State of Florida. The project has an installed generating capacity of 30,000 kilowatts and produces an estimated average of 250,000,000 kilowatt hours annually. Power from the project is sold to six preference customers located within a radius of 150 miles of the Project under rate schedule JW-1 (Revised) and also to the Florida Power Corporation under rate schedules JW-2 (Revised) and JW-2-B.

³16 U.S.C. §825s

⁴E.G., *Southeastern Power Administration*, Docket No. EF79-3021, order issued February 27, 1981, *Bonneville Power Administration*, Docket No. EF80-2011, order issued November 21, 1980.

⁵See DOE Secretarial Delegation Order No. 0204-4.

¹This referral was made pursuant to Department of Energy Secretarial Delegation Order No. 0204-33 and the pertinent provisions of the Flood Control Act of 1944.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY
COMMISSION

ELECTRIC RATES: Federal Rates

December 29, 1978, ERA disapproved the filed rates on the basis that they were higher than necessary to recover the cost of producing and transmitting the power and energy sold from the project. The rate schedules subsequently filed with the Commission in this docket by AS/RA are essentially identical to those previously filed with and rejected by ERA. However, the instant filing reflects increases in capital costs and other expenses.

SEPA's PRS indicates that, based on estimates of future revenues and expenses, all applicable costs, including investments made in replacement items with service lives extending beyond the 50-year repayment period, will be repaid by the end of fiscal year 2007 (the fiftieth year after the project commenced commercial operation). While we have previously questioned certain of the practices reflected in SEPA's repayment studies,⁶ our analysis in the instant docket demonstrates that these practices have relatively small revenue effects which are partially offsetting and which do not serve as a basis for disapproval of SEPA's rates. We find the proposed rates to be consistent with the statutory requirements, and we shall therefore confirm and approve those rates. However, this confirmation of the proposed rate schedules should not be construed as approval of the specific practices or methodologies reflected in SEPA's repayment study.

The Commission Orders:

(A) SEPA's rate schedules JW-1 (Revised) and JW-2-B are hereby confirmed and approved for the period October 20, 1979, through August 19, 1982.

(B) The Secretary shall promptly publish this order in the Federal Register.

By the Commission.

(SEAL)

Kenneth F. Plumb,
Secretary

⁶For example, the Commission has indicated that it is contrary to general practice to recover during the 50-year repayment period replacement costs associated with items that have service lives continuing beyond the repayment period. In addition, in Docket No. EF79-3021 (order issued February 27, 1981), we expressed concern regarding (1) inconsistencies in calculating operation and maintenance expenses and future replacement costs, (2) failure to assess interest expense for new project additions and replacements for the year in which they commence service (see DOE order No. RA 6120.2, issued September 1979), and (3) the practice of repaying selected high-interest investments ahead of the required repayment date and postponing repayment of lower-interest investments. With respect to the latter point, we noted that "[d]espite the Commission's stated concern regarding this repayment methodology, in exercising our appellate type review function, we are not prepared to conclude at this time that the AS/RA policy lacks a rational basis."

Before Commissioners: Georgiana Sheldon, Acting
Chairman; Matthew Holden,
Jr., and J. David Hughes.

United States Secretary of Energy,)
Southwestern Power Admin-) Docket No.
istration) EF 79-4011

ORDER DISAPPROVING AND REMANDING
RATES, AND GRANTING INTERVENTIONS
(ISSUED JUNE 3, 1981)

On March 5, 1979, the Assistant Secretary for Resource Applications of the Department of Energy¹ filed with the Federal Energy Regulatory Commission a request for confirmation and approval on a final basis of certain rates and charges for the sale of power by the Southwestern Power Administration (SWPA).

The proposed *system rate* schedules and contract rates of SWPA include the following:

Rate Schedule P-3, Hydro Peaking and Seasonal
Peaking Power;

Rate Schedule F-2, Firm Power from Integrated
System;

Rate Schedule F-3, Firm Power through Oklahoma
Utilities Companies;

Rate Schedule EE-2, Excess Energy;

Rate Schedule IC-2, Interruptible Capacity; and

Contract Rate under section 2 of the Tex-La Electric
Cooperative, Inc. Contract No. 14-02-001-864.

The above rates are requested to remain in effect through September 30, 1983. In addition, the filing proposed that Rate Schedule P-3 be applied to power and energy sales under section 1.02 and that Rate Schedule EE-2 be applied to secondary energy sales under section 1.04 of the contract among SWPA, Arkansas Power and Light Company, and the Reynolds Metals Company, Contract No. Ispa-514 (Aluminum Contract).

Public notice of the filing was published in the Federal Register on May 4, 1979, and a Notice of Correction

¹The Assistant Secretary for Resource Applications was given authority to file rates with this Commission by DOE Delegation Order No. 0204-33, issued December 28, 1978, 43 FR 60636. On March 19 and April 9, 1981, the Secretary of Energy transferred DOE's power marketing responsibilities to the Office of the Assistant Secretary for Conservation and Renewable Energy.

of the filing was published in the Federal Register on August 8, 1979. The first notice required protests and interventions to be filed with the Commission on or before May 16, 1979, and the second notice provided that comments be filed on or before August 27, 1979. Petitions to intervene were filed by the City of Piggott, Arkansas, Tex-La Electric Cooperative Inc., Arkansas Power & Light Company, Reynolds Metals Company, and Associated Electric Cooperative, Inc. In addition, untimely petitions to intervene were filed by the Committee on Power for the Southwest, Inc., the City of Fulton, Missouri, and the City of Lamar, Missouri.

Commission Authority And Standards Of Review

The authority delegated to the Commission by the Secretary of Energy is that of confirming and approving on a final basis, or disapproving rates approved on an interim basis by the Assistant Secretary. The Commission must insure that the rates submitted by the Assistant Secretary satisfy the standards of the Flood Control Act of 1944.² The Act provides that:

1. Project power and energy must be transmitted and disposed of in a manner that encourages the most widespread use thereof;
2. Rate schedules shall be drawn having regard to the recovery of the cost of producing and transmitting such energy, including amortization of the capital investment, over a reasonable period of years; and
3. Rates to consumers should be the lowest possible consistent with sound business principles.

Unlike our statutory authority under the Federal Power Act or the Natural Gas Act, the statutory mandate accorded to the Commission under the power marketing legislation does not include the power to modify the tendered rates. The power marketing acts vest the responsibility to develop the rates in the first instance in the Administrator of SWPA. Those rates are transmitted to the Assistant Secretary for confirmation and approval on an interim basis. The interim rates and supporting record are then submitted to the Commission for final confirmation and approval, or disapproval.

In November and December of 1980,³ the Commission issued two orders discussing its review responsibility with respect to federal rates. The Commission therein determined that its role could be viewed as in the nature of an appellate function: to affirm, reverse, or remand the rates submitted to it for final review. The Commission determined that in order to discharge this review function

it must be apparent from the record before the Commission that the Administrator's development of rate schedules and the Assistant Secretary's interim approval are rational and consistent with the statutory standards. Therefore, under the federal power marketing statutes, the Commission must determine, on the basis of the supporting data and information submitted, whether the rate schedules will provide a sufficient level of revenue to SWPA to recover its annual costs and to repay the federal investment within a reasonable period of time. In addition, the Commission must make a determination as to whether the rates developed by the Administrator are the lowest possible (consistent with sound business principles) and have been drawn with a view to encouraging the widest possible use of the project power and energy.

SWPA Rate Schedules and Support

The SWPA filing includes certain rate schedules and a repayment study which purports to support the rate filing. The repayment study contains an estimate of revenues for the time period for which the approval is being sought. We find the SWPA filing deficient in two important respects: it appears to significantly underestimate the costs of supplying energy and power; and it does not provide critical information to allow us to determine whether the rates are consistent with the statutory standards and the regulations issued by the Assistant Secretary to implement these standards. Specific deficiencies are discussed below.

First, SWPA reduced its estimate of replacement costs for the entire system by 35 percent based on the assumption that the Army Corps of Engineers, the agency responsible for operating SWPA's power plants, has been recovering replacement costs in its charges for ordinary maintenance expenses. This assumption appears to be based on the findings of a special replacement study prepared by the Corps for one project, the Sam Rayburn Dam. However, there is nothing in the Corps' study that justifies applying the 35 percent reduction to other projects in the SWPA system. Based on an estimate supplied by SWPA, it appears that this unusual downward replacement cost adjustment will lead to an annual revenue shortfall of approximately \$1.2 million.

Second, the SWPA study underestimates interest charges. A review of the Corps' 1979 Form 1 Annual Report for the Stockton Lake Project shows that the interest expense for that project is underestimated in the SWPA Power Repayment Study (PRS) by \$2,719,822. SWPA has also underestimated interest expenses on other projects. In earlier years, SWPA's filing indicates failure to recover all of its annual costs and, as a result, by the end of FY 1977, SWPA had accumulated a deficit of \$23,843,597. DOE regulations (R.A. Order No. 6120.2) require that the interest rate used in computing the carrying charges on such deficits be current interest rates applicable in each year (as defined in the

²16 U.S.C. 825s.

³U.S. Secretary of Energy, *Bonneville Power Administration*, Docket No. EF80-2011, Order Remanding Rates With Prejudice, issued November 21, 1980; U.S. Secretary of Energy, *Bonneville Power Administration*, Docket No. E-9563, Order Remanding Rates Without Prejudice, issued December 1, 1980.

regulation) rather than project interest rates (i.e., the interest rate specified in the project authorization or the interest rate applicable at the time construction was initiated). It appears that SWPA ignored this directive. SWPA's use of the generally lower project interest rates in place of current interest rates appears to produce a significant understatement of annual revenue requirements. The application of project interest rates to deficits and the understatement of the Stockton Lake Project interest expenses are estimated to cause an annual shortfall in required revenues of approximately \$2.5 million.

Third, in developing its replacement cost estimates, SWPA used an outdated publication, issued by the Bureau of Reclamation in October 1963, rather than a more recent publication, *Replacements — Units of Property and Service Lives* (March 1968). Our analysis indicates that SWPA's use of the outdated publication to estimate future replacement costs will result in an additional annual revenue deficiency of about \$400,000.

Fourth, SWPA contends that the proposed rate increase is needed in part because of expected increases in the cost of purchased power. The SWPA filing indicates that the price paid for purchased power will range from an average of 20.3 mills per kilowatt-hour in FY 1979, to 26.1 mills per kilowatt-hour in FY 1982. From a review of current firm power costs in SWPA's service area, it appears that SWPA's price estimates are on the low side. Therefore, unless SWPA provides further information there is strong reason to doubt that its filed rates will provide sufficient revenues to cover purchased power costs.

Fifth, the SWPA study combines replacements with the original project investment. The non-segregation of replacement costs makes it impossible for us to determine whether replacement costs are being repaid on a timely basis consistent with the statutory standards. This is a reporting deficiency that prevents us from performing our review function. However, it probably does not have a direct revenue impact.

When reviewing the rate filings of federal power marketing agencies based upon extended repayment studies, we may overlook minor deficiencies if the level of rates is generally consistent with the mandates of the Flood Control Act. However, we would be remiss in our statutory obligations if we overlooked major deficiencies that lead to significant shortfalls. We estimate that the first three deficiencies in the SWPA filing will result in an annual revenue shortfall of approximately \$4.1 million, or about 6 percent of gross revenues. To the extent that these revenues are not collected from SWPA's customers, they will be borne by taxpayers. We are disapproving this filing because we do not believe that Congress intended for us to approve rates that would not be sufficient to reimburse taxpayers for their investment.

Aluminum Contract

One difficult issue remains: how to treat known cost deficiencies for service to a customer that may not be recovered from that customer because of legally binding contract provisions?

In January 1952, Arkansas Power & Light Company (AP&L) and Reynolds Metals Company (Reynolds) entered into a contract with SWPA. The contract obligates SWPA to provide electricity to AP&L and Reynolds for a thirty-year period beginning January 1, 1954, and ending December 31, 1983. The contract, as supplemented on April 25, 1952, provided for certain maximum rate increases at the end of each five year period for the duration of the thirty-year contract. On April 28, 1952, the Federal Power Commission confirmed and approved the schedule of rates and charges as filed in the supplemental agreement.

In the instant filing, SWPA has determined that the maximum contract rate is insufficient to meet the repayment requirement and, therefore, seeks to apply to these companies the same rates being charged for similar service to other customers.

AP&L and Reynolds brought action in the United States District Court for the District of Columbia to prevent SWPA from increasing the rate in excess of the maximum increase provided in the contract. By Memorandum Opinion filed October 20, 1980, the District Court ruled that SWPA could not legally increase the rate beyond the contract rate, regardless of whether the rate for service to AP&L and Reynolds would produce revenues sufficient to cover the costs for the service.

As previously noted, the standards of section 5 of the Flood Control Act of 1944 require that the applicable rate schedules provide sufficient revenues for SWPA to recover its annual costs and to repay the federal investment within a reasonable period of time. Accordingly, absent legislative action, the estimated \$2.1 million annual revenue deficiency produced by the Aluminum Contract must be recovered in charges to other customers.

The Record On Other Issues

Our decision to disapprove the rate and remand the record in this docket obviates the need to address other issues at this time. However, for purposes of guidance, the Commission will set forth its current views with respect to the adequacy of the existing record as to certain of the issues raised by the intervenors.

Associated Electric Cooperative, Inc. has protested a transmission service charge which is assessed when SWPA provides service off its transmission system. The Cooperative contends that the service charge concept is contrary to the intent of Congress. Since legislation (P.L. No. 95-456, 92 Stat. 1230, enacted October 13, 1978) specifically provides for mutually satisfactory contract negotiations to be held between Associated and

SWPA, the issue is not appropriate for resolution by the Commission in this rate filing.

Tex-La Electric Cooperative, Inc. asserts that SWPA and the Corps of Engineers have failed to substantiate that an annual revenue increase of approximately \$15 million over the next five years is required to fulfill their responsibilities under section 5 of the Flood Control Act. In light of the large increases in O&M expenses incurred for the integrated system in the recent past, it appears that SWPA's estimates of future O&M costs are reasonable and necessary to insure that costs are recovered.

With respect to contract issues other than those posed by the Aluminum Contract and discussed above, the remand provides an opportunity for the Assistant Secretary, if he so desires, to consider allegations that the amount of energy provided and interim rates for customers of SWPA are in violation of any contractual obligations between the parties. As we noted in *Bonneville Power Administration*, Docket No. EF80-2011, order issued November 21, 1980, the Commission is not disposed to inquire into the legal authority of the Assistant Secretary to place rates in effect on an interim basis. The Commission's view is that this is a matter for disposition by the Assistant Secretary in the first instance, subject to appellate court review.⁴

Finally, the Commission believes that the disapproval and remand makes a hearing before the Commission unnecessary and inappropriate at this time. Although the Commission has the authority to institute a hearing whenever necessary, we would expect that necessary due process and hearing requirements generally should be satisfied when the proposed rates are being considered by the Assistant Secretary. As previously noted, the responsibility for developing the rates resides with the Assistant Secretary acting by and through the Administrator of SWPA. Thus, we do not now envision any formal hearings before the Commission.

Conclusions

Upon review of SWPA's filing, we find that the record transmitted by SWPA in this docket contains major deficiencies and is not sufficiently developed to allow a fully reasoned determination as to whether the rates meet the applicable statutory criteria. Therefore, it is necessary to disapprove the rates and to remand the record to the Administrator and Assistant Secretary for purposes of correcting those deficiencies and providing additional explanation.

With respect to the various petitions to intervene, we find that participation in this proceeding by each of

the petitioners is in the public interest and that good cause exists to grant the untimely petitions. Accordingly, we shall grant intervenor status to each of the petitioners.

The Commission orders:

(A) The rates and charges developed by the Administrator of the Southwestern Power Administration, and placed in effect on an interim basis by the Assistant Secretary for Resource Applications, are hereby disapproved and remanded for correction of the stated deficiencies and further development of the record in order to demonstrate that the rates and charges submitted are in accord with the applicable statutory standards.

(B) The Assistant Secretary for Conservation and Renewable Energy shall submit substitute rates with adequate support to the Commission within 120 days from the date of this order.

(C) The petitions to intervene filed by the City of Piggott, Arkansas, Tex-La Electric Cooperative, Inc., Arkansas Power and Light Company, Reynolds Metals Company, Associated Electric Cooperative, Inc., the Committee on Power for the Southwest, Inc., the City of Fulton, Missouri, and the City of Lamar, Missouri are hereby granted subject to the rules and regulations of the Commission; *provided, however*, that participation by the intervenors shall be limited to matters set forth in their petitions to intervene; and *provided, further*, that the admission of the intervenors shall not be construed as recognition by the Commission that they might be aggrieved because of any order or orders by the Commission entered in this proceeding.

(D) The Commission, herein specifically provides that Petitions for Reconsideration may be filed with the Commission not later than 30 days from the date of this order.

(E) The Secretary shall promptly publish this order in the Federal Register.

By the Commission.

(SEAL)

Kenneth F. Plumb,
Secretary

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY
COMMISSION

United States Secretary of Energy
Southwestern Power Administration
System Transmission Rates

Docket No. EF81-4051

⁴This issue was recently addressed by the United States District Court for the District of Oregon. See *Pacific Power & Light Co. v. Charles William Duncan, Jr., et al.* (Civil Docket No. 80-82, September 30, 1980).

ORDER CONFIRMING AND APPROVING RATES (Issued July 31, 1981)

On December 12, 1980, the Assistant Secretary for Resource Applications of the Department of Energy¹, on behalf of the Southwestern Power Administration (SWPA) filed with the Federal Energy Regulatory Commission a request for confirmation and approval on a final basis of Transmission Rate Schedule TDC-2.

SWPA at present has thirteen customers being billed for transmission service under Schedule TDC-2, and under current usage the proposed filing would increase SWPA's annual wheeling revenues about ten percent, from \$465,000 annually to \$510,000 annually. The Assistant Secretary is requesting that the transmission rate schedule be approved on a final basis through September 30, 1983. The rates are currently in effect on an interim basis through December 31, 1981.

Notice of the filing was published in the Federal Register on January 12, 1981. Interested parties were invited to petition to intervene or protest the filing on or before January 26, 1981. No protests or petitions to intervene were received.

The transmission rate schedule was developed to recover a proportionate share of the annual costs of the Federal transmission system of SWPA. Based on the type of service furnished, SWPA classified the type of usage into either capacity or energy use. Capacity usage was further classified into three voltage levels: deliveries made at 138 or 161 kV, deliveries made at 69 kV, and deliveries below 69 kV. Cost and load data were determined for each classification and each classification was allocated its proportionate share of transmission system cost in the rate calculation. The rate for energy usage was based on total system cost and load factors obtained from the Southwest Power Pool's "10-year Energy and Peak Demand Data". The daily rate for the new interruptible service was derived from the firm monthly rate for each voltage level classification assuming twenty-two days per month usage.

The cost of repaying the Federal investment in SWPA's transmission is based on a compound interest amortization method. This method of amortization conforms to repayment of an investment by providing for the gradual extinguishment of the obligation by payment of part of the principal with or at the time of each periodic interest payment. Since the service life of transmission facilities is less than the usual maximum repayment period of fifty years, SWPA has used a composite forty-five year

amortization period for repayment purposes. Repayment in any year is a summation of the amortization costs (including interest) for each major investment in service and the operating and maintenance costs for the transmission estimated to be required that year.

It is noted that this filing does not follow in all regards the financial reporting requirements adopted by the Department of Energy in Order No. RA 6120.2. For example, supporting data was not submitted demonstrating that the amortization period, repayment status, and estimates of O&M costs conformed with RA 6120.2.

In the instant filing, sufficient information was provided to determine that the overall revenues generated through the use of Transmission Rate schedule TDC-2 will be reasonably sufficient to recover the costs associated with SWPA's transmission service.

It Is Ordered That:

The proposed Southwestern Power Administration Transmission Rate Schedule TDC-2 filed on December 12, 1980, to be effective for the period January 1, 1981, through September 30, 1983, is hereby confirmed and approved.

William W. Lindsay, Director
Office of Electric Power Regulation

UNITED STATES OF AMERICA FEDERAL ENERGY REGULATORY COMMISSION

United States Secretary of Energy Docket No. EF80-1011
Alaska Power Administration
Eklutna Project

ORDER CONFIRMING AND APPROVING RATE SCHEDULES (Issued August 3, 1981)

By letter filed December 4, 1979, the Assistant Secretary, Resource Applications (AS/RA), on behalf of the Alaska Power Administration (APA) filed a request for confirmation and approval, on a final basis, of Wholesale Power Rate Schedules A-F8 and A-N7 for a five-year period ending December 31, 1984.¹ These rate schedules, applicable to power from the Eklutna Project, replace Schedules A-F7 and A-N6 previously confirmed and approved by the Federal Power Commission through December 31, 1979. By Rate Order No. APA-2, dated December 4, 1979, the AS/RA approved the rate

¹The Assistant Secretary for Resource Applications was given authority to file rates with this commission by DOE delegation Order No. 0204-33, issued December 28, 1978, 43 FR60636. On April 9 and March 19, 1981, the Acting Secretary of Energy transferred DOE power marketing responsibilities to the Assistant Secretary for Conservation and Renewable Energy. Authority to act on this matter is delegated to the Director, Office of Electric Power Regulation, under section 375.308 of the Commission's Regulations.

¹Pursuant to section 2 of the Eklutna Project Act (64 Stat. 382) and the Department of Energy Secretarial Delegation Order No. 0204-33. Subsequently, effective February 24, 1981, the Secretary of Energy abolished the Office of AS/RA and transferred DOE's power marketing responsibilities to the Office of the Assistant Secretary for Conservation and Renewable Energy. Authority to act on this matter is delegated to the Director, Office of Electric Power Regulation, under section 375.308 of the Commission's Regulations.

schedules on an interim basis for the period January 1, 1980, through December 31, 1980. On November 20, 1980, the AS/RA extended the interim approval through December 31, 1981.

Notice of the AS/RA's filing was published in the Federal Register on January 9, 1980, with petitions to intervene or protests due on or before January 30, 1980. No petitions or protests were filed.

The Eklutna Project is a single-purpose power project comprised of a dam, reservoir, 30,000 kW hydroelectric plant, 45 miles of transmission lines, and four substations serving the Anchorage and Palmer, Alaska area. The project is operated and maintained, and its power marketed by APA.² The total Federal investment of \$30,237,373 is subject to repayment with revenues derived from power sales.³ Pursuant to a 1969 operating agreement, APA sells the total firm output, estimated to average 153,000,000 kWh annually, to its three wholesale power customers.⁴ An additional 11,000,000 kWh of non-firm energy is also estimated to be available for sale to these customers each year.

The rate schedules submitted for approval in this docket will produce a revenue level approximately that which is required to recover costs over the repayment period.

Although the reasonableness of several of the items contained in the power repayment study may be questionable,⁵ the aggregate effect on annual revenues is relatively small. In addition, on January 16, 1981, the AS/RA approved recommendations by its staff which are expected to resolve many of the issues noted and improve the analyses in support of future filings.

In light of the foregoing and the lack of protest or petition to intervene in this proceeding, it is appropriate and in the public interest to approve and confirm APA Rate Schedules A-F8 and A-N7 for the period January 1, 1980, through December 31, 1984.

²The Eklutna Project, completed in 1955, was constructed and operated by the U.S. Bureau of Reclamation until 1967 when APA was established by the Secretary of Interior.

³In accordance with the Eklutna Project Act, the Federal Power Commission was assigned responsibility for allocating the costs of the Eklutna Project. By FPC Order issued October 18, 1963, the FPC determined that all project costs are properly allocable to power.

⁴These customers are: Matanuska Electric Association, Chugach Electric Association, and the City of Anchorage.

⁵The items noted for appropriate consideration in future filings are: (1) the treatment of interest expense for new project additions and replacements for the years these investments begin service, (2) the methodologies in estimating future operation, maintenance, and replacements costs, (3) the use of outdated estimates of future revenues, and (4) the practice of "borrowing" from an already repaid investment account.

It Is Ordered That:

Rate Schedules A-F8 and A-N7 are confirmed and approved for the five-year period ending December 31, 1984, as requested by the AS/RA.

William W. Lindsay, Director
Office of Electric Power Regulation

UNITED STATES OF AMERICA FEDERAL ENERGY REGULATORY COMMISSION

United States Secretary of) Docket No. EF80-5041
Energy
Western Area Power Administration
Parker-Davis Project

ORDER CONFIRMING AND APPROVING RATE SCHEDULES (Issued October 29, 1981)

By letter filed May 19, 1980, the Assistant Secretary, Resource Applications (AS/RA), on behalf of the Western Area Power Administration (Western), filed a request for confirmation and approval, on a final basis, of Wholesale Power Rate Schedule PD-F1 and Transmission Service Schedules PD-T1, PD-T2, and PD-T3 for a five-year period ending June 30, 1985.¹ These rate schedules, applicable to power and transmission service from the Parker-Davis Project, replace Rate Schedule LC-F2 and wheeling charges stipulated in contracts previously approved by the Secretary of the Interior. By Rate Order No. WAPA-3, dated May 15, 1980, the AS/RA approved the rate schedules on an interim basis, effective the first day of the first full billing period beginning on or after June 16, 1980. On May 14, 1981, the interim approval was extended through June 30, 1982.

Notice of the filing was published in the Federal Register on June 3, 1980, with petitions to intervene or protests due on or before June 16, 1980. No petitions or protests were filed.

The Parker-Davis Project is a Federal multiple-purpose water project with generating facilities located on the Colorado River below Hoover Dam and a transmission system which serves parts of Nevada, California, and Arizona. The project's transmission system is operated and maintained and its power marketed by Western and the other project facilities are administered by the

¹Pursuant to the Department of Energy Secretarial Delegation Order No. 0204-33. Subsequently, effective February 24, 1981, the Secretary of Energy abolished the Office of AS/RA and transferred DOE's power marketing responsibilities to the Office of the Assistant Secretary for Conservation and Renewable Energy. Authority to act on this matter is delegated to the Director, Office of Electric Power Regulation, under section 375.308 of the Commission's Regulations.

U.S. Bureau of Reclamation. As of 1984, estimated Federal investment costs of \$122,005,000 allocated to the power function and \$27,210,000 allocated to the Mexican Water Treaty and the irrigation function must be repaid from power revenues over the remainder of the repayment period in addition to annual operating expenses and replacements. Project facilities (irrigation and drainage projects) receive 193,305 MWh of annual firm output. Western sells the remaining firm output, estimated to average 1,013,000 MWh annually, to 11 wholesale power customers and provides wheeling service to the Colorado River Storage Project and others within its service area.

The rate schedules submitted for approval in this docket will produce a revenue level approximately that which is required to recover the costs over the repayment period.

Although the reasonableness of several of the practices contained in the power repayment study may be questionable², the aggregate effect on annual revenues is relatively small.

In light of the foregoing and the lack of protest or petition to intervene in this proceeding, it is appropriate and in the public interest to approve and confirm Western Rate Schedules PD-F1, PD-T1, PD-T2, and PD-T3 for the period June 16, 1980, through June 30, 1985.

It Is Ordered That:

Rate Schedules PD-F1, PD-T1, PD-T2, and PD-T3 are confirmed and approved for the five-year period ending June 30, 1985, as requested by the AS/RA.

Willaim W. Lindsay, Director
Office of Electric Power Regulation

²The items noted for appropriate consideration in future filings are: (1) the practice of "borrowing" from an already repaid investment account, (2) probable increase in revenues from transmission services after existing contracts expire, and (3) providing additional support for the data used in the power repayment study.

**DEPARTMENT OF ENERGY
DELEGATION ORDER NO. 0204-4**

**TO THE ADMINISTRATOR OF THE ECONOMIC
REGULATORY ADMINISTRATION**

Pursuant to the authority vested in me as Secretary of Energy ("Secretary") and by the Department of Energy Organization Act (Pub. L. 95-91) (the "DOE Act"), the Administrator of the Economic Regulatory Administration ("ERA") is hereby directed to provide by rule for a separation of the regulatory and enforcement functions of the Economic Regulatory Administration, in accordance with Section 206(a) of the DOE Act; and

There is hereby delegated to the Administrator of ERA the authority to adopt rules, issue orders, licenses and allocations, collect fees, and take such other actions as may be necessary and appropriate to administer the following functions:

1. The allocation and pricing of crude oil, residual fuel oil, and refined petroleum products, pursuant to the provisions of the Emergency Petroleum Allocation Act of 1973 (Pub. L. 93-159), as amended;

2. The importation of crude oil, unfinished oils and finished products, pursuant to the provisions of the Trade Expansion Act of 1962 (Pub. L. 87-794) and Proclamation No. 3279, as amended;

3. The prohibition of powerplants and major fuel burning installations from the use, as a primary energy source, of natural gas or petroleum products; requiring that powerplants and major fuel burning installations in the early planning process be designed and constructed so as to be capable of using coal, pursuant to the provisions of Section 2 of the Energy Supply and Environmental Coordination Act of 1974 (Pub. L. 93-319), as amended;

4. The prescription of energy conservation and rationing contingency plans, pursuant to the provisions of Sections 202 and 203 of the Energy Policy and Conservation Act (Pub. L. 94-163), as amended;

5. The development of proposals for improvement of electric utility rate design and advising the Secretary of such proposals for the transmittal thereof to Congress; funding of electric utility rate demonstration projects; and providing financial assistance to State offices of consumer services to facilitate presentation of consumer interests before such commissions, pursuant to the provisions of Title II of the Energy Conservation and Production Act (Pub. L. 94-385), as amended;

6. The exportation and importation of natural gas, pursuant to the provisions of Section 3 of the Natural Gas Act (Pub. L. 688, 75th Cong. 2d Sess.), as amended, and Executive Order No. 10485, except with respect to those pending cases assigned by rule to FERC;

7. The exportation and importation of electric energy, pursuant to the provisions of Section 202(e) of

the Federal Power Act (Pub. L. 280, 66th Cong., 2d Sess.), as amended, and Executive Order No. 10485;

8. The establishment and review of priorities for the curtailment of deliveries of natural gas, under the authority of the provisions of Sections 1(b), 4, 5, 7 and 16 of the Natural Gas Act and pursuant to the provisions of Section 402(a) (1) (E) of the DOE Act;

9. The assembly of information with regard to State compacts, proposed and approved, dealing with the conservation, production, transportation or distribution of natural gas and advising the Secretary with respect to legislation recommended to carry out the purposes of such State compacts and to aid in the conservation, and orderly, equitable and economic production, transportation and distribution of natural gas, pursuant to the provisions of Section 11 of the Natural Gas Act;

10. The establishment and modification of regional districts in the country for the voluntary interconnection and coordination of facilities for the generation, transmission and sale of electric energy, and the promotion and encouragement of such interconnection and coordination within each such district and between such districts, pursuant to the provisions of Section 202(a) of the Federal power Act;

11. To order the temporary connections of facilities, during times of war or national emergency, for the generation or transmission of electric energy and such generation, delivery, interchange, or transmission of electric energy as in the Administrator's judgment will best meet the emergency and serve the public interest, pursuant to the provisions of Section 202(c) of the Federal Power Act.

12. To approve or deny applications to make permanent connections for emergency use only by persons engaged in the transmission or sale of electric energy where the applicant is not otherwise subject to the jurisdiction defined by Section 201 of the Federal Power Act, with any public utility that is subject to such jurisdiction, pursuant to the provisions of Section 202(d) of the Federal Power Act;

13. The investigation and determination, upon the Administrator's own motion or the request of any State commission, of the cost of production or transmission of electric energy by means of facilities that are subject to the jurisdiction defined by Section 201 of the Federal Power Act, as the Administrator determines is necessary and appropriate to perform his functions, pursuant to the provisions of Section 206(b) of the Federal Power Act;

14. The conduct of investigations regarding the generation, transmission, distribution and sale of electric energy, however produced, throughout the United States and its possessions, including the generation, transmission distribution and sale of electric energy by any agency, authority or instrumentality of the United States, or of any State or municipality or other political sub-

division of a State, and advising the Secretary of the results of such investigations for his report thereof to Congress, as the Administrator determines is necessary and appropriate to perform his functions, pursuant to Section 311 of the Federal Power Act;

15. Exercise of the authority under the acts listed below to confirm and approve power or transmission rates of federal power marketing agencies, and exercise of the cost-allocation authority contained in Section 7 of the Bonneville Project Act cited below: Section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s), the Bonneville Project Act of 1937 (Pub. L. 329, 75th Cong., 1st Sess.) as amended; the Federal Columbia River Transmission System Act of 1974 (Pub. L. 93-454), the Eklutna Project Act of 1950, as amended, (64 Stat. 382); the Act of June 18, 1954 (68 Stat. 255), as amended by the Act of December 23, 1963 (77 Stat. 475) (Falcon and Amistad Dams);

16. The final decision as to rate adjustments, pursuant to Section 10 of the rules entitled "Procedures for Public Participation in General Adjustments in Power Rates", set forth at 40 F.R. 34431-32 (August 15, 1975), which were promulgated pursuant to the Reclamation Act of 1902, 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 the acts specifically applicable to the project in question;

17. Exercise of the authority under Section 11 of the Clayton Act (U.S.C. §21) as related to the transportation of oil by pipeline, pursuant to the provisions of Section 306 of the DOE Act;

18. To propose rules, regulations and statements of policy of general applicability to the Federal Energy Regulatory Commission (FERC) with respect to any function within the jurisdiction of FERC under Section 402 of the DOE Act and set reasonable time limits for the completion of action by FERC on any such proposal, pursuant to the provision of Section 403(a) of the DOE Act;

19. To intervene or otherwise participate in any proceeding before FERC, pursuant to the provisions of Section 405 of the DOE Act;

20. To intervene or otherwise participate on behalf of the Secretary in any proceeding before any federal or state agency or commission whenever it is determined that the interests of the Secretary should be represented in such proceeding;

21. To issue Notices of Probable Violation (NOPV) when there is reason to believe that a violation of any regulation or order having the effect of a rule promulgated pursuant to the Emergency Petroleum Allocation Act of 1973 has occurred, is continuing or is about to occur, and conduct proceedings incidental thereto;

22. To issue proposed remedial orders and remedial orders (including matters involving remedial orders for

immediate compliance and orders of disallowance) for the violation of any regulation or order having the effect of a rule promulgated pursuant to the Emergency Petroleum Allocation Act of 1973, advise FERC as to any such remedial order that is contested, and set reasonable time limits for FERC to complete action on any such proceeding referred to it, pursuant to the provisions of Section 503 of the DOE Act;

23. To issue appeal decisions with respect to remedial orders (including remedial orders for immediate compliance and orders of disallowance) relating to NOPV's that were issued by the Federal Energy Administration prior to October 1, 1977;

24. To suspend or revoke allocations and licenses, and conduct proceedings incidental thereto, issued pursuant to the functions described in paragraph 2;

25. To provide for the making of adjustments to any rule, regulation or order having the effect of a rule, issued under the statutory authorities vested in and transferred to the Secretary pursuant to the DOE Act and which are not delegated by the Secretary to the Federal Energy Regulatory Commission, consistent with the other purposes of the relevant statutory authority, as may be necessary to prevent special hardship, inequity, or unfair distribution of burdens, and to provide by rule for procedures for any person to seek an interpretation, modification or rescission of, exception to, or exemption from any rule, regulation or order having the effect of a rule issued under such statutory authorities, pursuant to the provisions of Section 504(a) of the DOE Act;

26. To initiate and conduct investigations, when necessary and incidental to the exercise of any authority delegated herein, in response to complaints or other information; conduct conferences, hearings or public hearings with respect to the functions delegated hereby; administer oaths and affirmations to any person, and suspend or disqualify any person appearing at such conference or hearing; issue subpoenas; make payment, if appropriate, of witness fees and mileage to any witness appearing in response to such subpoenas; and take such other action as may be necessary and appropriate to assure and determine the extent of compliance with DOE rules and regulations described herein and any order having the effect of a rule issued thereunder;

27. To take such other action as the Secretary or his authorized delegates may, from time to time, direct or authorize.

The authority delegated to the Administrator of ERA may be further delegated, in whole or in part, as may be appropriate, provided that the Administrator shall not further delegate, in whole or in part, the authority delegated to him to propose or adopt rules.

The administrator of ERA shall consult with the Administrator of the Energy Information Administration

("EIA") with respect to the exercise of functions under Paragraphs 13 and 14, as EIA considers appropriate.

In exercising the authority delegated by this Order or as redelegated pursuant thereto, the delegate(s) shall be governed by the rules and regulations of DOE and the policies and procedures prescribed by the Secretary or his delegate.

All actions pursuant to any authority delegated prior to this Order or pursuant to any authority delegated by

this Order taken prior to and in effect on the date of this Order are hereby confirmed and ratified, and shall remain in full force and effect as if taken under this Order, unless or until rescinded, amended or superseded.

This Order is effective October 1, 1977.

James R. Schlesinger
Secretary of Energy

DEPARTMENT OF ENERGY
DELEGATION ORDER NO. 0204-33
TO THE ASSISTANT SECRETARY FOR
RESOURCE APPLICATIONS AND TO THE
ENERGY REGULATORY COMMISSION

Pursuant to the authority vested in me as Secretary of Energy and by Sections 203(a), 301(b), 302(a), 402(e), 641, 642, 643 and 644 of the Department of Energy Organization Act (Pub. L. 95-91):

1. There is hereby delegated to the Assistant Secretary for Resource Applications the authority to develop, acting by and through the administrators, power and transmission rates for the power marketing administrations, and the authority to confirm, approve, and place in effect such rates on an interim basis, for such period or periods as he may provide, subject to refund with interest as determined by the Federal Energy Regulatory Commission in accordance with Section 3 hereof. No rate developed by the Assistant Secretary shall become effective on a final basis unless and until such rate is confirmed and approved by the Federal Energy Regulatory Commission acting under Section 2 hereof.

2. There is hereby delegated and assigned to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve on a final basis, or to disapprove, rates developed by the Assistant Secretary under Section 1, and to exercise the cost allocation authority contained in Section 7 of the Bonneville Project Act and Section 2 of the River and Harbor Act of 1945, 59 Stat. 10, 21, 22.

3. In the event a rate developed by the Assistant Secretary is disapproved by the FERC, the Assistant Secretary shall within 120 days or such additional time periods as the FERC may provide, develop and submit to FERC a substitute rate for action by the FERC under Section 2 hereof. A rate confirmed and approved by the Assistant Secretary on an interim basis that is disapproved by the FERC shall remain in effect, as provided by the Assistant Secretary, until a substitute rate is confirmed and approved on a final basis by the FERC: *Provided*, That if the Assistant Secretary does not file a substitute rate within 120 days or such greater time as the FERC may provide, and if the rate has been disapproved because the FERC determined that it would result in total revenues in excess of those required by law, the rate last previously confirmed and approved on a final basis will become effective on a date and for a period determined by the FERC and revenues collected in excess of such rate during the interim period will be refunded with interest to the extent determined by the FERC. If a substitute rate confirmed and approved on a final basis by the FERC is lower than the rate in effect on an interim basis, any overpayment shall be refunded with interest as determined by the FERC. If a substitute rate confirmed and approved on a final basis by the FERC is higher than the rate in effect on an interim basis, such rate shall

become effective on a subsequent date set by the FERC. If at any time it is determined by the FERC that the administrative cost of a refund would outweigh the amount to be refunded, no refund will be required.

4. For purposes of this order—

(a) "Administrator" means the Administrator of a power marketing administration.

(b) "Power marketing administration" means the Alaska Power Administration, the Bonneville Power Administration, the Southeastern Power Administration, the Southwestern Power Administration, and the Western Area Power Administration.

5. This order is effective January 1, 1979.

Issue at Washington, D.C., this 21 day of December, 1978.

James R. Schlesinger
Secretary of Energy

DEPARTMENT OF ENERGY
AMENDMENT TO DELEGATION ORDER NO.
0204-33

TO TRANSFER AUTHORITY TO THE
ASSISTANT SECRETARY FOR CONSERVATION
AND RENEWABLE ENERGY

Pursuant to the authority vested in me as Acting Secretary of Energy and by Sections 203(a), 301(b), 302(a), 641, 642, 643, and 644 of the Department of Energy Organization Act (Pub. L. 95-91), Delegation Order No. 0204-33 is hereby amended by substituting "Assistant Secretary for Conservation and Renewable Energy" for "Assistant Secretary for Resource Applications."

All actions pursuant to any authority delegated prior to this order or pursuant to any authority delegated by this order taken prior to and in effect on the date of this order are hereby confirmed and ratified, and shall remain in full force and effect as if taken under this order, unless or until rescinded, amended, or superseded.

This Amendment is effective 19 March, 1981.

R. G. Romatowski
Acting Secretary of Energy

DEPARTMENT OF ENERGY SUPPLEMENT
TO DELEGATION ORDER NO. 0204-33
TO COVER CONFIRMATION OF BONNEVILLE
POWER ADMINISTRATION RATES ON AN
INTERIM BASIS

Pursuant to the authority vested in me as Secretary of Energy and by Sections 203(a), 301(b), 302(a), 641, 642, 643, and 644 of the Department of Energy Organization Act (P.L. 95-91), Delegation Order No. 0204-33 is

hereby supplemented by delegating to the Assistant Secretary for Conservation and Renewable Energy the authority vested in me as Secretary of Energy By Section 7(i)(6) of the Pacific Northwest Electric Power Planning and Conservation Act (P.L. 96-501) to approve rates for the Bonneville Power Administration on an interim basis. This delegation shall continue until December 5, 1981, or such earlier time as the Federal Energy Regulatory Commission shall have established interim rate approval procedures in final form. This action is necessary because the Federal Energy Regulatory Commission has determined the necessity to establish procedures for exercising the function under Section 7(i)(6) of the Pacific Northwest Electric Power Planning and

Conservation Act (P.L. 96-501) of approving, on an interim basis pending the Commission's final decision, rates submitted to it by the Bonneville Power Administration, and the Commission has further determined that it will not be able to establish such procedures prior to October 1, 1981.

All actions pursuant to any authority delegated prior to this order or pursuant to any authority delegated by this order taken prior to and in effect on the date of this order are hereby confirmed and ratified, and shall remain in full force and effect as if taken under this order, unless or until rescinded, amended, or superseded.

This supplement is effective June 19, 1981.

James B. Edwards
Secretary of Energy

U.S. DEPARTMENT OF ENERGY
WASHINGTON, D.C.
ORDER RA 6120.2
(September 20, 1979)

SUBJECT:
POWER MARKETING ADMINISTRATION
FINANCIAL REPORTING

1. *PURPOSE.* To establish financial reporting policies, procedures, and methodology for all Department of Energy (DOE) power marketing administrations (PMA's) except where deviations therefrom are specifically approved by the Secretary, authorized by statute, or identified and explained in a transmittal memorandum or in the footnotes to the reports.

2. *CANCELLATION.* Paragraph IV. F of INTERIM MANAGEMENT DIRECTIVE 1701, PRICING OF DEPARTMENTAL SERVICES AND PRODUCTS, OF 9-28-77.

3. *SCOPE.* The provisions of this order apply to the PMA's reporting to the Assistant Secretary for Resource Applications.

4. *REFERENCES.* Proposed procedures for adjustments in power and transmission rates of the PMA's, 44 F.R. 39184 (July 5, 1979), or such finally adopted procedures.

5. *AUTHORITY.* This order is issued pursuant to the authority of the Secretary of Energy under the Department of Energy Organization Act, Public Law 95-91, 42 U.S.C. 7101; the Reclamation laws, particularly Section 9(c) of the Reclamation Project Act of 1939, 53 Stat. 1194, 43 U.S.C. 485h(c); Section 5 of the Flood Control Act of 1944 58 Stat. 890, 16 U.S.C. 825s; the Bonneville Project Act, 50 Stat. 731, as amended, 16 U.S.C. 832 et seq.; the Federal Columbia River Transmission System Act, Public Law 93-454, 16 U.S.C. 838 et seq.; the Eklutna Project Act, 64 Stat. 382, as amended; Section 204 of the Flood Control Act of 1962, 76 Stat. 1193 (Snettisham Project); Reorganization Plan No. 3 of 1950, 64 Stat. 1262; Section 2 of the Act of June 14, 1966, Public Law 89-448, 80 Stat. 200, as amended; Section 303 of the Federal Power Act, 49 Stat. 855, 16 U.S.C. 825b; and related laws.

6. *POLICY.*

a. It is DOE policy to encourage sound businesslike financial management and accounting practices in routine accounting and the preparation of power system financial statements. Power system financial statements will be prepared in accordance with generally accepted accounting principles as prescribed by the American Institute of Certified Public Accountants, the Financial Accounting Standards Board, the General Accounting Office, and the Office of Management and Budget, as appropriate. To the extent practicable, the PMA's will maintain their accounts in accordance with the Uniform System of Accounts prescribed by the Federal Energy

Regulatory Commission for public utilities.

b. It is also DOE policy that power repayment studies will be prepared annually using sound and consistent financial forecasting techniques. These forecasts should be designed to approximate as closely as possible the results expected to be achieved in the historical power system financial statements.

7. *DEFINITIONS.*

a. *Assisted Irrigation Investment.* "Assisted irrigation investment" means the portion of construction costs of Federal Reclamation projects which are allocated to the irrigation purpose and are assigned pursuant to legal authorization for repayment from the revenues of the power system.

b. *Cost Evaluation Period.* "Cost evaluation period" means a period of time during which estimates of future costs and revenues may be modified to reflect changing conditions, normally 5 years.

c. *Cost Recovery Criteria.* "Cost recovery criteria" means the criteria set forth in paragraph 12, beginning on page 13.

d. *Investment or Power Investment.* "Investment" or "power investment" means unless otherwise indicated in the context, investment allocated to be repaid from power revenues.

e. *Power Marketing Administration.* "Power marketing administration" means the Alaska Power Administration, the Bonneville Power Administration, the Southeastern Power Administration, the Southwestern Power Administration, or the Western Area Power Administration.

f. *Power Repayment Study.* "Power repayment study" means a study (previously referred to as an average rate and repayment study or repayment study) portraying the annual repayment of power production transmission costs of a power system through the application of revenues over the repayment period of the power system. The study shows, among other items, estimated revenues and expenses, year by year, over the remainder of the power system's repayment period (based upon conditions prevailing over the cost evaluation period), the estimated amount of Federal investment amortized during each year, and the total estimated amount of Federal investment remaining to be amortized. The study does not deal with rate design. Power repayment studies may take two forms as described below:

(1) *Current Power Repayment Study.* A power study that utilizes currently established rates for estimating future revenues. The study reflects the same basic power system included at the time rates were approved.

(2) *Revised Power Repayment Study.* A study that utilizes, in whole or in part, proposed or assumed rates

for estimating future revenues. Typically, it is designed to demonstrate that potential revenue levels will satisfy the cost recovery criteria over the remainder of the power system's repayment period.

g. *Power System.* A system comprised of one project or more than one project hydraulically and/or electrically integrated and therefore treated as one unit for the purpose of establishing rates.

h. *Power System's Repayment Period.* A period extending to the final year allowed under the cost recovery criteria for amortization of the original investment in all projects included in the power repayment study.

i. *Secretary.* The Secretary of Energy.

8. THE ACCOUNTING SYSTEM.

u. *The Books of Account.* The books of account of all the PMA's will be kept in accordance with accounting systems that are approved by the General Accounting Office and any additional guidelines promulgated by the Secretary. The PMA's shall maintain their power systems accounts in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission for public utilities and licensees to the extent practicable. Supporting detailed information shall be maintained in a manner that facilitates a ready retrieval, analysis, and verification of pertinent facts. Books of account shall be kept on a monthly basis and closed at the end of each fiscal year.

b. *Accounting Concepts.* Accounting concepts for PMA's shall be developed around, but not limited to, the following generally accepted principles:

(1) *Period Cutoff Accounting.* There must be proper cutoff accounting at the beginning and end of the period to ensure that revenues and expenses are not overstated or understated.

(2) *Expenses Matched to Period Revenues.* Expenses shall be appropriately matched against the periodic revenues.

(3) *Current and Fixed Assets.* Assets shall be accounted for in a meaningful manner to assure fair presentation of the financial position. Current assets are to be carried at cost or market value, whichever is less; fixed assets are to be carried at cost of acquisition or construction; appropriate charges shall be made for depreciation of fixed assets.

(4) *Liabilities.* All known liabilities shall be recorded.

c. *Specific Power System Accounting Matter.* Specific accounting matters which are pertinent to PMA practices include, but are not necessarily limited to, the following:

(1) *Interest Rates.* Interest expense on the power investment shall be a required portion of the costs to be recovered by power revenues. Rates to be used in com-

puting interest shall be those rates officially established by law, or for all investment with no rate established by law made through 1-29-70, the rate established administratively for such investment, or for all investment made after 1-29-70, the rate established pursuant to paragraph 11, beginning at page 12, and related implementation guidelines.

(2) *Unpaid or Deferred Annual Expense.* Deficits (or unrecovered expenses) which occur in any year in which revenues fail to recover operation and maintenance, purchased and exchanged power, transmission service and other expenses, and interest expense shall be accrued on the balance sheet as a liability with interest at the rate prescribed in paragraph 11, beginning at page 12, for investment made in the fiscal year in which the losses were incurred.

(3) *Priority of Revenue Application.* Annual revenues will be first applied to the following recovery of costs during the year in which they are incurred: operation and maintenance (O&M), purchased and exchanged power, transmission service and other, and interest expense and any appropriation amortization of revenue bonds. Remaining revenues are available for amortization and shall be applied first to unpaid or deferred annual expense, if any, and then to the Federal investment. To the extent possible, while still complying with the repayment periods established for each increment of investment and unless otherwise indicated by legislation, amortization of the investment will be accompanied by application to the highest interest-bearing investment first.

9. FINANCIAL STATEMENTS

a. *Power System Financial Statements.* Power system financial statements shall, to the extent practical, be prepared in accordance with generally accepted accounting principles and concepts. Power system financial results shall be disclosed in a clear, concise, and complete manner. Annual financial statements, accompanied by explanatory footnotes and supporting schedules, shall fairly present the financial position for each PMA power system. Power system reporting requirements shall generally conform to any appropriate standards promulgated by the American Institute of Certified Public Accountants, the Financial Accounting Standards Board, the Federal Energy Regulatory Commission, and the General Accounting Office and shall include, but not necessarily be limited to (1) Statement of Revenues and Expenses or Income Statement; (2) Statement of Assets and Liabilities or Balance Sheet; (3) Statement of Source and Application of Funds or Statement of Changes in Financial Position; (4) Statement of Changes in Proprietary Capital (the statement may be incorporated in either the Statement of Revenues and Expenses or the Statement of Assets and Liabilities); and (5) the appropriate notes to financial statements.

b. *Statement of Revenues and Expenses (Income Statement)*. The results of operations shall be clearly and fairly reported on a comparative basis for the current and preceding fiscal periods. Net Revenues (or Deficit) presents the results of power system operations on a normal accrual accounting basis for the reporting period, after depreciation expense and interest on the unpaid Federal investment.

c. *Statement of Assets and Liabilities (Balance Sheet)*. The financial position of the power system for the current and preceding periods shall present the Federal investment in the power system on a cumulative basis and include a schedule of accumulated net revenues.

d. *Statement of Changes in Financial Position (Statement of Source and Application of Funds)*. A statement of changes in financial position shall be prepared on a comparative basis for the current and preceding fiscal periods to clearly describe the flow of funds of the power system for the reporting period. All power system funds shall be reported according to major source and disposition in a format which is appropriate to conventional regulated-company financial reporting.

e. *Notes to the Financial Statements and Supporting Tables*. Power system financial statements shall satisfy professional requirements for adequate, informative disclosure. Notes to the financial statements for each power system shall address, as a minimum, the following reporting matters (unless this information is provided elsewhere):

(1) *Summary of Significant Accounting Policies*. A description of all significant accounting policies of the power system. Policy disclosures shall include, at a minimum: (a) the basis of consolidation, (b) depreciation methods employed, (c) status of allocation of cost varying purposes on multi-purpose projects, and (d) amortization and repayment requirements related to the Federal power investment.

(2) *Subsequent Events*. Disclosure of material events and transactions occurring subsequent to the financial reporting period shall be included if necessary for proper interpretation of the financial statements.

(3) *Interest Rates*. Current policy regarding interest rates applicable to the reporting power system.

(4) *Non-depreciable Assets*. The amortization and reporting treatment of the Federal investment in land and other non-depreciable assets.

(5) *Contingent Liabilities*. A discussion of known major contingent liabilities.

f. *Auditor's Opinion*. The financial statements and accompanying notes to the financial statements of each power system shall be examined periodically, with the period not to exceed 2 years, by independent auditors, the General Accounting Office, Inspector General, or other acceptable audit organization. The results of this

examination shall be reported in a letter which describes the scope of the examination and expresses an opinion on the financial statements.

10. POWER REPAYMENT STUDIES.

a. *General Requirements*. Each PMA will prepare and publish annually a power repayment study for each power system. Each power repayment study consists of two parts, historical data and future data (forecasts). The development of future data requires the forecast of revenues, expenses and investment. The annual power repayment study will use sound and consistent forecasting techniques. Those forecasting techniques will be explained in a memorandum included with each forecast. The forecasts will utilize, to the extent possible, the accounting concepts set forth on page 4, paragraph 8. The power repayment study is updated annually to test the continuing adequacy of the existing rates. The annual study is called a *Current Power Repayment Study*. It reflects the same basic power system included at the time rates were approved, but forecasts current operating results and updated estimates of revenues and costs for the remaining years of the repayment study.

b. *Rate Adjustment Plan*. Whenever the current power repayment study shows that repayment requirements are not being met, action will be taken by the PMA to prepare and recommend a plan to be implemented at the next practicable time to satisfy the repayment requirements (or to explain why such requirements cannot be met).

Such plan may include increasing rates, decreasing costs, changing contracts, or any other viable means for meeting cost recovery criteria. This plan will be supported by a Revised Power Repayment Study which will meet the cost recovery criteria. The plan will be submitted to the Assistant Secretary for Resource Applications through the Office of Power Marketing Coordination for review and further action. In certain situations the plan could recommend that no action be taken to meet repayment requirements. While a revised power repayment study must be prepared at a minimum when a current power repayment study shows that repayment requirements are not being met, preparation is not limited to that situation.

c. *Cost Evaluation Period*. A period of time during which future estimates of costs and revenues may be modified to reflect changing conditions, such as additions to the power systems or inflation. This period of time is normally 5 years. Revenue and cost estimates for the remaining years of the power system's repayment period should reflect price levels, rate levels, and contractual commitments consistent with conditions anticipated during the cost evaluation period.

d. *Allowable Unamortized Investment*. Each increment of investment shall be carried as allowable unamortized investment for its repayment period in accordance with the following principles:

(1) *Duration of Repayment Period.* Unless otherwise prescribed by law, each dollar of investment is to be repaid with interest within a period not-to-exceed 50 years. Repayment periods of less than 50 years may be established when the facilities involved have useful life expectancies of less than 50 years. Such shorter repayment periods are appropriate for (a) replacement of power facilities and (b) transmission facilities which are developed and managed as transmission systems rather than as adjuncts to generating projects. In such cases, the expected useful life of the facility involved generally will be used as the repayment period. Such repayment periods may be adjusted from time to time, within the 50-year maximum, if changed conditions indicate a different estimated useful life expectancy.

(2) *Start of the Repayment Period.* The first year of the repayment period for both specific and joint cost shall be the fiscal year following the fiscal year in which the investment goes into commercial service. After each portion of allocated repayable power investment goes into commercial service, the total joint investment costs for a power generating facility shall, on a pro rata basis, be associated with the specific investment costs incurred in the initial stage of project development (the initial stage of development includes all power units which are initially constructed in a continuous sequence without a time lag or more than 5 years between generating units).

e. Revenues

(1) Power revenues shall be those expected through the power system's repayment period, based on contractual commitments for sales of power and energy that are expected to exist during the cost evaluation period.

(2) In the absence of specific contractual provisions for increased power sales, the revenue forecast will rely heavily on the past trends of actual customer load growth rates. Where contractual payments for power and/or quantities of such power and energy sales are defined, these shall form the basis for revenue determination.

(3) Power quantities for forecasting future revenues shall also include purchased and exchange power quantities which are consistent with contractual commitments that are estimated to exist during the cost evaluation period, and only to the extent that related costs are also projected. The revenue forecast shall also consider capacity increases resulting from facility additions which are projected to be commercially operational within the cost evaluation period. A schedule comparing revenue estimates for the previous period with actual revenue realized should be included with the annual submission. Miscellaneous revenues shall be included where appropriate, as well as headwater benefit payments to be made to the Treasury for power benefits to non-Federally owned utility hydroplants.

(4) Power quantities used for estimating revenues, unless defined by contract, are determined by theoretical reservoir operation studies based on historical stream flows. In preparing these operational studies, hydrological data, current to within 5 years if possible, and available engineering data will be used, recognizing restrictions imposed by other project functions. Input data will be revised and updated whenever new information indicates that a significant change in the forecast can be expected in the future where there is a significant variance between the forecasted and actual results, but in any event not less frequently than once every 5 years unless an accepted explanation is provided concerning why this is not necessary.

f. *Operation and Maintenance Costs.* Estimates of O&M costs shall be developed with heavy reliance placed on historical cost trends and actual project costs in the past. The use of various cost indices, developed from and supported by project history, is recommended in developing the forecast and testing its reliability. In preparing the estimate, actual costs will be compared to past forecasts to identify sources of variance and previous projection errors. A schedule showing these comparisons will be included with the annual power repayment update. The forecast shall take into account known factors which are expected to affect the future level of such costs during the cost evaluation period.

g. *Purchased and Exchange Power Costs.* All costs of planned purchased power during the cost evaluation period shall be included in the power repayment study.

h. *Transmission Service and Other Costs.* These costs, to be estimated for the cost evaluation period, include payments to others required by legislation, "wheeling" payments for use of transmission capacity, rental payments for the use of electrical facilities, payments for detriment caused by project facilities or operation, payments for increased benefits furnished by others, credit payments under certain contracts, and interconnection costs for which a payment is made based on contractual commitments.

i. *Interest Rates.* Interest rates shall be established as set forth on page 4, paragraph 8c(1) for historical and current rates. Forecasts will utilize the rate established in paragraph 11, beginning on page 12, and related implementation guidelines for the latest available year for all future years.

J. *Interest Expense.* Interest expense for each of the years of the study will be the sum of the amounts determined by: (1) applying the applicable interest rate to each estimated unamortized power investment at the beginning of the year; plus (2) applying one-half the applicable interest rate to power investments (i.e., additions and replacements) expected to be added and in service during the year; plus (3) applying the applicable interest rate to capitalized unpaid or deferred annual expense, if any. If the interest credit

concept is utilized by the PMA, the interest credit should be offset against interest expense.

k. *Investment Costs.* The power repayment studies will include all investment cost allocated to power for the existing systems. Additionally, the allocated power investment costs of all authorized power system facilities for which Congress has appropriated funds for construction and which will be in service within the cost evaluation period will be included. The investment cost will include construction cost of the project as well as interest during construction, computed using the same rate as determined in paragraph 10i.

l. *Replacements.* Future replacement costs will be included in repayment studies by adding the estimated capital cost of replacement to the unpaid Federal investment in the year each replacement is estimated to go into service, and adding it to the allowable unamortized investment. The capital costs of each replacement is determined by estimating the cost at current price levels of the new unit of property, less salvage, if any, at the end of the service life of the unit replaced. The allowable unamortized investment is developed by adding each year's investment as it goes into service and then deducting each increment of investment at the end of its allowable repayment period. Replacements should be accounted for separately from the original investment.

m. *Status of Repayment.* For any year of a power system study, the status of repayment can be determined comparing the allowable unamortized investment with the unamortized investment. For every year that the unamortized investment is equal to or less than the allowable unamortized investment, repayment is on or ahead of schedule. If for any year the unamortized investment exceeds the allowable, the cost recovery criteria are not being met.

n. *Content and Format of Power Repayment Study.* Power repayment studies for all power systems shall be accompanied by a statement of pertinent assumptions used in preparing the studies. Further, there should be submitted a schedule which will show significant changes as compared with the previous study and a comparison of the previous forecast to actual performance for the same period. The format of the power repayment studies prepared by the PMA's will be expected to vary to some extent due to differences in conditions among PMA's, e.g., some have transmission systems, while others do not.

11. INTEREST RATE FORMULA.

a. Except as otherwise provided by law, the interest rate to be used for computing interest during construction and interest on the unpaid balance of the costs of a Federal power project or system transmission facilities, the construction of which is initiated after 1-29-70, which are properly allocated to commercial

power development, shall be the applicable rate, as hereinafter provided, during the fiscal year in which funds are first appropriated to initiate construction of such projects or facilities. For purposes of this paragraph, a Federal power project or system transmission facilities may be any of the following so long as it is treated as a separate entity for repayment purposes:

(1) A Federal reservoir project which includes the generation of electric power that is marketed by a PMA and which may also include a transmission system;

(2) Any unit or separable power feature of such Federal reservoir project; or

(3) Federal transmission lines, substations and appurtenant facilities under the administration of a PMA that are not a part of a Federal reservoir project.

b. Each fiscal year, the Assistant Secretary for Resource Applications will request the Secretary of the Treasury to inform the Office of Power Marketing Coordination of the computations made as of October 1 in accordance with paragraph 11c for the preceding fiscal year. If the yield rate so computed does not differ from the applicable interest rate used by the PMA's for the previous fiscal year by more than $\frac{1}{2}$ percent, the applicable rate to be used by the PMA's shall be equal to the yield rate. If the yield rate differs from the applicable interest rate used by the PMA's for the previous fiscal year by more than $\frac{1}{2}$ percent, the applicable rate to be used by the PMA's shall be the applicable rate used in the previous fiscal year increased or decreased by $\frac{1}{2}$ percent toward the yield rate.

c. For the purposes of this paragraph the yield rate is the average yield during the preceding fiscal year on interest-bearing marketable securities of the United States which, at the time the computation is made, have terms of 15 years or more remaining to maturity. The average yield shall be computed as the average during the fiscal year of the daily bid prices. Where the average rate so computed is not a multiple of one-eighth of 1 percent, the rate of interest shall be the multiple of one-eighth of 1 percent nearest to such average rate.

d. The Assistant Secretary for Resource Applications, through the Office of Power Marketing Coordination, shall annually advise the PMA's of the applicable interest rate for the current fiscal year.

12. *COST RECOVERY CRITERIA.* The current rates for a power system will be adequate if, and only if, a power repayment study indicates that:

a. The expected revenues are at least sufficient to recover annually, except for a possible initial short transition period:

(1) All costs of operating and maintaining the power system during the year in which such costs are incurred; plus,

(2) The cost of acquiring power through purchase and/or exchange agreements, the costs for transmission services, and other costs during the year in which such costs are incurred; plus,

(3) Expensed interest on the unamortized investment in Federal power facilities in the year for which the interest charges are assessed, except that recovery of the annual interest expense may be deferred in unusual circumstances for short periods of time; plus,

(4) Interest and amortization of revenue bonds where PMA's are authorized to issue such bonds.

b. In addition to the recovery of the above costs on a year-by-year basis, the expected revenues are at least sufficient to recover:

(1) Each dollar of power investment at Federal hydroelectric generating plants within 50 years after they become revenue producing, except as otherwise provided by law; plus,

(2) Each annual increment of Federal transmission investment within the average service life of such transmission facilities or within a maximum of 50 years, whichever is less; plus,

(3) The cost of each replacement of a unit of property of a Federal power system within its expected

service life up to a maximum of 50 years; plus,

(4) Each dollar of assisted irrigation investment within the period established for the irrigation water users to repay their share of construction costs; plus,

(5) Other costs such as payments to basin funds, participating projects or States.

13. *SUBMISSION.* Power system financial statements and power repayment studies will be forwarded to the Assistant Secretary for Resource Applications and shall be accompanied by a statement from the PMA Administrator that the financial statements and power repayment studies are in compliance with this order. Any deviation therefrom shall be disclosed and justified. Copies of power system financial statements and power repayment studies will be provided for policy guidance, evaluation of methodology, and compliance review, and shall be delivered within 180 days of the close of the applicable fiscal year.

FOR THE SECRETARY OF ENERGY:

George S. McIsaac
Assistant Secretary for
Resource Applications

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY
COMMISSION

United States Department
of Energy,)
Southwestern Power Admin-) Docket No. EF79-4011
istration)

PETITION FOR RECONSIDERATION

In accordance with the Federal Energy Regulatory Commission's (Commission) specific provision for filing of Petitions for Reconsideration in Docket No. EF79-4011, Order Disapproving and Remanding Rates, and Granting Intervention (Order) issued June 3, 1981, the Southwestern Power Administration (Southwestern) does hereby Petition for Reconsideration in such Order.

Introduction

The Order indicates filing deficiencies in two major areas: underestimating costs of supplying energy and power; and lack of critical information to allow the determination of the adequacy of the rates as regards statutory standards and implementation of those standards. The specific deficiencies discussed in the Order will each be treated in some detail in the ensuing dissertation. We are, however, at a decided disadvantage in responding to certain of the Commission's contentions, inasmuch as we are advised by the Commission's staff that the Commission's rules regarding *ex parte* communication with staff block any attempt at even simple clarification of the meaning of some statements in the Order. While we appreciate the opportunity to Petition for Reconsideration, the effectiveness of the Petition to clarify or correct the deficiencies noted by the Commission is severely diminished by the paucity of detail provided in the Order alone.

Background and Assumptions

A power repayment study (PRS) is prepared to test the adequacy of existing rates to repay expected annual costs over a specified cost evaluation period and at the same time amortize the Federal investment in power production and transmission facilities in a reasonable period of years. The development of such PRS involves many variables, and assumptions or estimates must be made as to the conditions which will persist both over the cost evaluation period and past it.

The first basic assumption which must be made to enable any PRS to commence is that of a cut-off point — a point in time after which no changes in initial conditions or assumptions can be made. This cut-off point is delayed as long as possible to assure the information and data used in the study are the latest and best available. Without such a cut-off point no repayment study could be completed, since every day and month can cause

changes to the conditions assumed, even in the best of faith, only a short time before. In this light, however, regular updates of the PRS and all conditions expected in the ensuing cost evaluation periods, will quickly correct for even major variations in assumptions made previously. Other assumptions, while important to the immediate evaluation of the adequacy of rates, are always subject to the cut-off point and limited to the best information available at the time. The rapidly changing nature of Southwestern's business and the assumptions necessary to review the adequacy of rate levels make imperative the rapid review of filed rates to avoid potential conflicts in assumptions between one study and the next which are self-correcting over the long-term. When a rate awaits approval for a period of some 2 1/4 years after filing, and the accompanying PRS includes some data and estimates made as much as 2 years prior to filing, obviously a great number of changed conditions have occurred in the intervening years. However, if the PRS and the filed rate are evaluated based on the reasonableness and rationality of decisions and estimates made at the time of PRS development, subsequent PRSs and filed rates will correct any actual deficiencies experienced and develop new estimates based on then-current conditions.

Another basic assumption includes the use of average water conditions to simulate both availability and sales of hydroelectric energy and purchases required to supplement such hydroelectric energy. Thus, the estimates of sales and purchases, while projected for each year of the cost evaluation period based on the specific contract and resource conditions predicted at that time, truly represent average results expected assuming a repeat of experienced stream flow. Further assumptions are necessarily predicated on this basic assumption of average water conditions. One assumption primary to the study's determination of repayment of investment is how revenue is distributed to investments after all annual operating expenses are met. This distribution will affect all subsequent calculations of interest expense on unpaid investment. Thus, it should be readily seen that Federal rates supported by a PRS must be evaluated on the basis of their reasonableness and the rationality of decisions supporting the assumptions and estimates made. The time frame and circumstances surrounding the preparation of the PRS must be considered in the evaluation, and the effects of subsequent events out of the control of the estimator, should not be allowed to totally confuse the review of rates, but must be foregone until a subsequent PRS is developed.

Deficiencies

(1) Replacements — Adjustment

When the PRS was prepared as support for Southwestern's current rate filing, concern had been expressed, by both customers and the staff of Southwestern, over the Corps of Engineers' (Corps) apparent practice of expensing replacements as a part of ordinary annual

operation and maintenance (O&M) costs. This concern led to speculation that Corps estimates of future O&M would include a component for replacements and, thus, the estimates of replacements in the PRS would duplicate expenses already predicted in Corps O&M estimates. These concerns, after discussion with the Corps, appeared justified and led to the adjustment of Southwestern's replacement estimates pending further study. However, the adjustment was not made entirely for this reason alone, although the PRS tends to indicate that it was. Previously, Southwestern had been estimating replacements based upon a publication prepared by the U.S. Bureau of Reclamation (Bureau) for projects constructed by the Bureau. The justification for using this data, rather than, for instance, data prepared by the Corps for projects in the Southwest, was that the relatively "young" projects in the Southwest had not had sufficient life to accurately project future replacements, that O&M had been of such high quality that replacements were not yet necessary, and that a major Corps study was pending nationwide to deal with the replacement problem.

While the Bureau study was used as the basis for Southwestern's replacement estimates, doubt lingered as to both its applicability and accuracy for projects in the Southwest. The Corps had agreed to begin a major study of replacements, but could not prepare such a study for use in the current PRS. A study for the Sam Rayburn Dam project had, however, been prepared for use in the Sam Rayburn PRS as justification for that project's rate filing. A significant difference between the Corps' new study and the use of the Bureau's study was that the Corps' study estimated replacement costs at current cost levels, while Southwestern attempted to estimate current cost levels by use of the Handy-Whitman Index of Construction Costs as applied to the total original cost of each project. Replacements were then predicted based on the procedures of the Bureau replacement Study. While the process was the best available at the time, considerable doubt was expressed as to its accuracy. Results obtained from the Corps' replacement study for Sam Rayburn were compared with the results obtained from Southwestern's estimates using the Bureau's replacement study. The Corps' study required replacements only 65% as great as Southwestern's estimates from the Bureau's study with updated costs. The variance in results was too great to overlook. Thus, since the Sam Rayburn project was approximately the average age of most of Southwestern's projects, we decided to use the new study as representative of results expected from a project-by-project study and applied the 35% reduction to each project's estimated replacements. Subsequent to the filing of Southwestern's rates with the Commission, the major project-by-project replacement study was initiated by the Corps and has since been completed. The results of this new study justify a reduction in Southwestern's earlier estimates of major project replacement costs by 30.5%, as compared to the 35% reduction used.

We have included as Exhibit "I", two tables, A and B. Table A shows the replacement data included in the filed PRS by year and service life. Table B shows the results of the Corps' new replacement data as it would appear in similar format. As can be seen, while service lives vary somewhat, total investment in replacements is within 5% of the data used in the filed PRS. Thus, we feel the reduction used was entirely appropriate, justified and reasonable considering the concerns and the data available at that time. The new study results will be used in the development of Southwestern's next PRS.

(2) Interest Charges

The second deficiency spoken to in the Commission's Order relates to Southwestern's estimate of interest expenses. Two significant items are noted as justification for this criticism: the apparent major error in estimating interest in FY 1979 for the Stockton Lake project and the use of project interest rates in calculating interest on deficits rather than current interest rates as required by DOE regulations.

Calculation of interest expense in the PRS uses certain simplifying assumptions to arrive at reasonable estimates of annual interest costs. Among these assumptions is the determination of interest only on the net unrecovered investment each year. Other components of interest expense, such as deficit interest and interest credit are separately calculated from total deficit and net revenue, rather than on a project-by-project basis. Thus, the total results obtained in the PRS may be comparable to total interest accumulated by project, but are not necessarily comparable individually. The interest calculated is also dependent upon such assumptions as the occurrence of average water conditions, which may affect the speed with which a project is repaid. In contrast, actual interest on investment calculated and paid is a result of water conditions actually experienced. Actual water conditions may cause the project to be repaid at a faster or slower pace than average water conditions.

In the case of the noted understatement of interest expense for the Stockton Lake project in FY 1979 in the amount of \$2,719,822, the figure \$2,719,822 is indicated in the Form 1 Annual Report for the project as an adjustment to prior fiscal year interest expense for the period FY 1973-1978, and was not a part of the calculated FY 1979 interest expense. Notes to the Balance Sheet, the Statement of Income for the Year, as well as Notes to the Statement of Income for the project in FY 1979 (attached as Exhibit 2) point out this adjustment, as well as the actual interest expense for the year. Since this adjustment had no relationship to the calculation of the current FY 1979 interest expense; it is inaccurate to classify the variance as indicative of an underestimate of interest expenses for all projects. We would also note that this adjustment to prior years' interest could in no way have been predicted by Southwestern's staff and obviously does not represent any flaw in the method of determining interest expense in the PRS. Instances such

as this occur infrequently as a result of many factors which may require the Corps, from whom we receive project interest expense figures, to recalculate interest.

Another consideration in the case of the Stockton Lake project is its unique situation as a project with both on-site and off-site power investment. Approximately \$18.4 million of on-site power investment, with attendant annual interest expense is to be repaid by Southwestern, while most of the remaining \$6.5 million of off-site power investment and related annual interest expenses are allocated to a power company for repayment. Approximately \$500,000 of this \$6.5 million is allocated to the Harry S. Truman project for repayment. Thus, the interest and investment figures from the Form 1 for the Stockton Lake project must be analyzed with care in comparing them with figures in the PRS. Of the \$2,719,822 prior year interest adjustment made, only \$2,027,697 is attributable to on-site power production repayable by Southwestern. In addition, only \$466,207 of the total interest expense of \$625,110 for FY 1979 is repayable by Southwestern.

For these reasons, we view as highly inappropriate, the comparison of estimated individual project interest expense with interest expense reported in the Form 1. The two sets of figures are simply not comparable in this fashion. The estimates calculated in the PRS by project are based on a simulation of average water conditions and are then totaled for the system. The adjustments for interest credit and deficit interest are subsequently made to account for total system interest expense. Interest expense reported in the Form 1 by project includes adjustments for interest credit, deficit interest and other items. It must be remembered that other factors as noted above can affect the interest estimates both positively and negatively. If a comparison must be made, the total actual system interest expense should be compared with the total estimated system interest expense with appropriate adjustments made to insure meaningful comparisons. Exhibit "3" provides such a comparison.

The Order also notes as accumulated deficit of \$23,843,597 through FY 1977. While the appearance of this "deficit" in the filing accurately reflects the status of repayment of 11 of the 19 operating projects in the integrated system as shown on the Form 1 for individual projects, an actual "deficit" for which funds must be appropriated does not exist. The overall Federal system status of repayment including transmission facilities is positive. The remaining project "deficit" resulted from the retention of funds by Southwestern since 1974, during a disagreement with the Corps of Engineers over distribution of revenues. This disagreement has, in part, been resolved and, as of September 10, 1980, funds were redistributed to eliminate entirely these accounting "deficits".

The PRS, in calculating interest expense on these prior "deficits", applied the same interest rate as the Corps

applies to these "deficits" in its interest calculations. This is the project interest rate as prescribed in Corps regulations (ER37-2-10). All future operating deficits, of which there are none in the Revised PRS, would be calculated at current interest rates in the PRS. This procedure is the same as that regarding replacements to which the Corps applies project interest rates in its interest calculations and Southwestern applies current interest rates in its PRS for future replacements. Since the accounting "deficits" were entirely repaid in both the PRS and actual practice by FY 1980, and the interest rates used in both cases were the same, no significant difference would be seen in expensed interest. The PRS operated under the assumption that the accounting "deficits" could be eliminated at any time with the resolution of the revenue distribution disagreement and since the interest being accumulated by the Corps on those "deficits" was at the project rates, we would be arbitrary to calculate interest at any other rate than that actually experienced.

Therefore, in light of the foregoing information, we feel that interest expenses, as calculated in the PRS, reasonably reflect actual total system interest expenses reported by the Corps and repaid by Southwestern. We also feel that we cannot reasonably be expected to predict adjustments to prior year interest calculations over which we have no control and that, in any event, these cost increases, or decreases, will be accumulated as a part of historical costs to be included in each update of the PRS. We can, in no way, validate the Commission estimate of an annual shortfall of \$2.5 million as the result of so-called deficiencies as stated in the Order.

(3) Replacements — Estimates

The third deficiency addressed in the Order concerns Southwestern's use of a 1963 Bureau replacement publication to predict future project replacements. The Order recommended the use of a March 1968 Bureau replacement publication. As we indicated in our response under (1) Replacements — Adjustment, the Corps' new replacement study justified our earlier 35% downward adjustment of the replacement estimates based on the 1963 Bureau publication. In future PRSs we will be using the Corps' new study to predict future replacements. Since the 35% downward adjustment of the original data proved accurate, the use of the March 1968 Bureau publication, also now outdated, would be unnecessary and unjustified.

(4) Purchased Power Costs

Southwestern's purchased power costs are dependent upon many factors, including contract terms available, surplus thermal generation in the area, fuels used, water conditions, the quantities of power needed, and the periods of time when power is needed. The price for purchased power varies widely as a result of each of these factors. Southwestern is, in many cases, able to mitigate its unit purchase costs by prudent use of its hydro

resources. Of course, Southwestern many at times, be forced to purchase at relatively high prices to conserve project storage to guarantee the availability of capacity, but those times are rare indeed.

Of course, Southwestern many at times, be forced to purchase at relatively high prices to conserve project storage to guarantee the availability of capacity, but those times are rare indeed.

In the PRS, Southwestern made its best estimates of the average cost of direct purchased energy, under average conditions. As stated in the Order, these cost estimates varied from 20.3 mills per kilowatt hour in FY 1979 to 26.1 mills per kilowatt hour in FY 1982. Average conditions assumed that exchanged energy would comprise approximately 35% of total required energy "purchases". Thus, effective costs for obtaining energy (purchasing and exchanging) under average conditions ranged from 13.2 mills per kilowatt hour in FY 1979 to 17 mills per kilowatt hour in FY 1982. Actual costs would be expected to vary depending upon the effects of the various factors listed earlier. Prices for direct purchases of 130.3 GWH in FY 1978 ranged from 14 to 35 mills per kilowatt hour, averaging some 23.5 mills per kilowatt hour. However, through the use of exchange arrangements, for which there is no direct charge, we received 235.4 GWH, causing the effective unit price for obtained energy to be only 8.4 mills per kilowatt hour, far below the estimated average cost of 11 mills per kilowatt hour for FY 1978. In FY 1979, direct purchases reached 330.5 GWH, and prices ranged from 16 to 27 mills per kilowatt hour, averaging 21.5 mills per kilowatt hour. Exchanged energy of 174.1 GWH reduced the average cost of the energy obtained to 14.1 mills per kilowatt hour. While the relationship of exchanged energy to total purchases matched expected average conditions, the quantity of total purchases exceeded average requirements significantly, causing the average unit cost to exceed the estimate of 13.2 mills per kilowatt hour only slightly in FY 1979.

We remain convinced that, considering the various factors affecting Southwestern's purchased power costs, the estimates made in 1976 remain the very best possible, particularly in light of the actual experience gained since that time. We continue to promote exchange energy arrangements which tend to mitigate the effects of rising unit purchase costs.

(5) Replacements — Reporting

The last deficiency noted in the Order is a reporting deficiency concerning replacement costs. We agree that the lack of this detailed information does not have an impact on revenue. For clarification, we have provided as Exhibit "A" a detailed expansion of Table I-A of the Revised PRS and of Statement C of our filing. Table I A is found at Page 67 of Southwestern's field PRS. Attached Exhibit "4" will enable the Commission staff to evaluate in more detail column (6) titled "Amortization" and column (7) titled "Added Investment" as relates to re-

placement investments. This information demonstrates repayment within service life and should satisfy the staff as to the repayment of replacement costs "on a timely basis consistent with statutory standards."

(6) Aluminum Contract

We recognize the problem that exists with the issue of the court order which disallows application of the system rate to the Aluminum Contract and restricts collection of revenues to only the contract rate. However, we contend that issues such as this, which invalidate assumptions valid at the time of filing, should not necessarily be cause for disapproving or remanding the filed rates. Southwestern is undergoing rapid and major contract changes which extend far beyond the final year of the cost evaluation period (FY 1982) in the filed PRS. A new PRS will reflect major contract changes whose net benefits exceed the short-term loss in revenues from the Aluminum Contract. Yet it would defeat the basic purpose of the PRS and its cost evaluation period to change continuously the data and assumptions made earlier. The assumption that the system rates would be applicable under the Aluminum Contract was made on basis that our position with regard to legal challenge was secure.

In addition to the validity of the assumption in the first instance, the magnitude of certain contract changes subsequent to the filing more than offset the potential loss of revenue foreseen in this instance. The Order speaks to "The Record on Other Issues" and mentions specifically the transmission service charge protest of Associated Electric Cooperative, Inc. (Associated). A mutually satisfactory contract was consummated between Southwestern and Associated on March 6, 1981, thus implementing the provisions of Public Law No. 95-456, 92 Stat. 1230, enacted October 13, 1978. Our evaluation of the new contract provisions indicates a net annual benefit to the Government exceeding \$3.6 million over provisions of the old contract. We have now eliminated the transmission service charge as required by the law. We feel this is another example of a major change in conditions not specifically anticipated at the time of the rate filing. However, this change more than compensates for the revenue "lost" under the Aluminum Contract lawsuit.

Both of these issues point to the necessity of timely Commission action on Federal rate filings, of evaluating the rate filings based on conditions anticipated at the time of the filing, and allowing subsequent changes in conditions to be reflected in subsequent PRSs and rate filings. To do otherwise would make any PRS and rate filing deficient from its inception.

Other Issues

Southwestern faces a significant legal problem as a result of the Commission's disapproval and remand of this rate filing. Since the interim rates have been disapproved because they are purportedly "too low", the possibility exists that higher substitute rates may be

approved and placed into effect at some later date by the Commission. This action would forever leave the Assistant Secretary's interim rates lacking final confirmation and approval. While there appears to be no immediate need for the rate to be approved on a final basis as far as collection of revenues goes, we may be trapped in a dilemma involving certain of our contract provisions which limit application of new rates to rates with "final" approval. This is the subject of present litigation. As long as our filed rates are approved, we have no dilemma, since the interim rates are approved on a "final" basis retroactive to the effective date of the interim rates. However, if the interim rates are not approved, as appears may be the case, we are in jeopardy of losing a portion, if not all, of our revenues during the interim period. This is clearly not the intent of the Commission, since it suggests a higher rate is needed.

We also are concerned with the apparent overlap of time frames involving the 30-day period for filing of our Petition for Reconsideration and the concurrent 120-day period for submission of substitute rates. We fear that the Commission's evaluation of our Petition for Reconsideration could use a significant part of the time allowed for submission of substitute rates. Without relief from this arbitrary deadline, we may be forced to submit substitute rates under unrealistic and unfavorable conditions.

Conclusions and Requests

We feel the information and responses included in this Petition for Reconsideration warrant favorable action on this long delayed rate filing. We continue to be persuaded that the filed rates are rational, consistent with, and adequate to satisfy the cost recovery criteria included in Section 5 of the Flood Control Act of 1944.

WHEREFORE, for good cause shown, and for the foregoing reasons, Southwestern respectfully request that the Petition for Reconsideration be granted and the following matters be considered:

1. The Commission place in abeyance the 120-day requirement for filing substitute rates until it has ruled on Southwestern's instant Petition for Reconsideration;
2. The Commission accept Southwestern's responses in its Petition for Reconsideration as adequate support for its original filing, and move to confirm and approve on a final basis the rate filing as submitted March 1, 1979; or
3. If the Commission finds it must still insist on correction of any or all of the noted deficiencies, the Commission grant an informal hearing among Commission staff, Southwestern and the intervenors to consider further amplification and clarification of the issues; and
4. If the Commission, after subsequent hearing, maintains that higher substitute rates must be filed, the Commission will confirm and approve on a final basis the lower interim rates as filed, from the effective date of the interim rates through the date substitute rates are confirmed and approved and placed in effect by the Commission.

Respectfully submitted,

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Southwestern Power Administration
Department of Energy

July 1, 1981

DEPARTMENT OF ENERGY

10 CRF PART 903

Subpart A Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions¹

AGENCY: Department of Energy, Resource Applications

ACTION: Final regulations

SUMMARY: Notice is given that the Assistant Secretary, Resource Applications has adopted regulations establishing common public participation procedures for power and transmission rate adjustments and extensions for four Power Marketing Administrations (PMAs) of the Department of Energy: Alaska Power Administration, Southeastern Power Administration, Southwestern Power Administration, and Western Area Power Administration. The Bonneville Power Administration is not included because the newly enacted Pacific Northwest Electric Power Planning and Conservation Act, P.L. 96-501 (December 5, 1980), establishes unique procedural requirements for Bonneville rate adjustments. The regulations govern the development of rate proposals by the Administrators of the four PMAs and the confirmation and approval of rates on an interim basis, subject to refund, by the Assistant Secretary for Resource Applications pursuant to the authority delegated by the Secretary of Energy in Delegation Order No. 0204-33, 43 FR 60636 (December 28, 1978).

Proposed procedures were published in the *Federal Register* July 5, 1979, 44 FR 39184. Opportunities for oral presentation of views were provided in Washington, D.C., on July 27 and August 17, 1979, and written and oral comments were received from more than 40 individuals and entities.

DATE: The regulations are effective upon publication.²

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SUPPLEMENTARY INFORMATION:

I. Introduction

The Assistant Secretary for Resource Applications by Delegation Order No. 0204-33, 43 FR 60636 (December 28, 1978) has been delegated, effective January 1, 1979, the authority to develop, acting by and through the Administrators, power and transmission rates for the Alaska, Bonneville, Southeastern, Southwestern, and Western Area Power Administrations (PMAs). The Assistant Secretary, by the same delegation order, was given the authority to confirm, approve, and place such rates in effect on an interim basis subject to refund. The order also delegated to the Federal Energy Regulatory Commission (FERC) the authority to confirm and approve such rates on a final basis.

The regulations adopted herewith are designed to establish common procedures for public participation in the development of new, revised, or extended power and transmission rates for four of the five PMAs, for confirming, approving, and placing such rates in effect on an interim basis, and for submittal of the rates and supporting documents to the FERC for confirmation and approval on a final basis. The procedures apply only to the activities of the four PMAs and the Assistant Secretary. The FERC is responsible for the formal or informal procedures it will follow in exercising its authority under the delegation order.

The first formal procedures for public participation by any of the five PMAs were published in the *Federal Register* on August 15, 1975, 40 FR 34431, for the Bureau of Reclamation after review of the public comments on the proposed rules, 40 FR 22156 (May 21, 1975). The other PMAs have followed similar procedures. The Alaska and Southwestern Power Administrations follow an informal practice on a case-by-case basis. The Bonneville Power Administration follows the "Procedures for Public Participation in Marketing Policy Formulation," 42 FR 62950 (December 14, 1977), amended by 45 FR 73531 (November 5, 1980); the Southeastern Power Administration has available the "Procedure for Public Participation in the Formulation of Marketing Policy," 43 FR 29186 (July 6, 1978); and the Western Area Power Administration follows the procedures previously used by the Bureau of Reclamation with amendments to adapt them to the establishment of the Western Area Power Administration in the Department of Energy, 43 FR 12076 (March 23, 1978), amended by 44 FR 7796 (February 7, 1979).

The regulations adopted herewith are in large part based on the experience that has been gained by the PMAs since 1975 in the conduct of 20 or so rate adjustment proceedings. The procedures used in the previous proceedings have received substantial acceptance by the customers. Basically, they have consisted of the preparation of power repayment studies, showing the need for a rate adjustment and the revenue level necessary to meet the repayment requirements; and a rate design

¹Includes corrections made Jan. 16, 1980 (46 FR 6864 dated 1/22/81).

²45FR 86976 dated 12/31/80

study which explains how the unit charges were derived. A consultation and comment period of at least 90 days has been allowed to answer questions concerning the proposed rate and to receive written and oral comments. During this time interested customers and others were supplied with copies of the repayment and rate design studies, a public information forum was typically held at which questions concerning the rate proposal were answered, and a public comment forum was held to afford interested members of the public the opportunity to submit comments to the Department.

A draft of the proposed regulations was published in the *Federal Register* of July 5, 1979, 44 FR 39184. Hearings were held in Washington, D.C., on July 27 and August 17, to receive oral comments, and written comments were invited to be submitted by September 4, 1979. In response to these opportunities, written and oral comments were received from more than 40 individuals or groups, a list of which is included in the notice. Also, written comments were submitted by the PMAs and by staff of the Assistant Secretary for Policy and Evaluation. Subsequent comments were received from staffs of the FERC and the Economic Regulatory Administration (ERA). In addition to reviewing and considering all of the comments, we also have had the benefit of the experience gained in the issuance of several additional rate orders after the proposed regulations were published for comment. Of these, the rate adjustment involving the largest amount of money was Rate Order BPA-2, 44 FR 70517 (December 7, 1979). This also was the most complex rate proceeding.

During this period, the Department converted the Department of the Interior's guidelines for Financial Reporting, which appeared as Chapter 4 of Part 730 for the Departmental Manual (DM), into an order of the Department of Energy, designated RA 6120.2, "Power Marketing Administration Financial Reporting." The provisions of 730 DM 3 relating to the repayment interest rates also have been incorporated into RA 6120.2 as paragraph 11. This conversion was technical only, and no substantive changes were made. RA 6120.2 supplements the regulations adopted today.

Because of the existence of RA 6120.2, it has been decided to eliminate the sections of the proposed regulations which essentially duplicate it; that is, §903.4 (Cost recovery), §903.10 (Corrective action), and the definition of and other references to power repayment studies.

Public commenters indicated strong opposition to portions of the proposed §903.5 on rate design; namely subsection (b) on cost analysis, subsection (d) on conservation, and subsection (e) on the PURPA standards. Rate design is in a continuing stage of development and includes complex issues which have not been fully resolved. We have concluded that these regulations are not the appropriate vehicle to establish

general rate design guidelines which would be followed by the PMAs in their development of various power rates. For these reasons, the section on rate design has been deleted from the regulations. This is discussed further under II(1) and II(2) below.

With the deletion of the cost recovery and rate design criteria sections, these regulations are now essentially limited to their primary purpose—procedures for public participation in the rate adjustment process.

The major issues raised by the oral and written comments are discussed in the next section of this statement followed by a section-by-section commentary explaining and discussing the minor and technical comments, and responses thereto.

Rate adjustments for the Bonneville Power Administration are not covered by these regulations because the newly enacted Pacific Northwest Electric Power Planning and Conservation Act establishes unique procedural requirements for new rate actions for Bonneville. It is anticipated that new regulations will be developed for application to Bonneville's rates only. However, the Act and any new regulations thereunder will not apply to the completion of the pending review of Bonneville's December 20, 1979, system rates and July 1, 1977, transmission rates.

These procedures shall become effective December 31, 1980, except that they will not apply to rate adjustments that have already been announced as required by §903.13.

Historically, many PURPA-type standards have been used in designing wholesale rates for the sale of Federal hydroelectric power. PMAs analyze costs to establish revenue requirements and consider this information in designing rates. Declining block rates for energy were once used by the PMAs but subsequently were found inappropriate and eliminated from rate schedules. Many of the PMAs for years have been effectively using various forms of load management measures in their rate schedules, such as scheduling limitations, loadshaping, capacity and energy overrun charges, etc. BPA has had a history of using seasonal rates for wholesale firm capacity and energy and also offered its direct service industrial customers interruptible rates some time ago. Southwestern has had interruptible capacity rates in effect since 1957. These examples demonstrate the willingness of the PMAs to implement PURPA-type standards where applicable.

Many of these PURPA-type standards, when applied appropriately in the design of PMA rates, can serve to implement the purposes of PURPA by encouraging conservation of energy, efficient use of resources and facilities, and equitable rates. The public participation process will provide an opportunity to examine these and other appropriate concepts.

The PMAs will continue to review and revise their power marketing practices on a system-by-system basis to serve

the PURPA objectives. The Assistant Secretary for Resource Applications, working with the Administrators of the power administrations, and after receiving public comment, will consider the adoption of rate design guidelines, similar in form to the guidelines in RA 6120.2 on financial accounting and ratemaking, which will reflect the experience gained by the PMAs in their system-by-system approach to rate design.

(2) Rate Design — Cost Determination

§903.5(b) of the proposed procedures, after stating that a cost of service analysis should be made, contained the following sentence: "However, cost need not be the sole determinant of price." The fear was expressed that the sentence would be used by the Department arbitrarily to increase rates to market value to promote conservation which would be a radical departure from and in violation of the requirement of the power marketing statutes that rates shall be the lowest possible to recover costs consistent with sound business principles. Others recognized that such an interpretation was ruled out by the provision of §903.5(a) that overall revenue levels were to be determined in accordance with the cost recovery criteria of §903.4(a), but nonetheless urged that the sentence be deleted as misleading in singling out one factor, namely cost, which would not be the sole determinant of price, while failing to recognize that there were numerous other factors which also might be considered but also would not be the sole determinant of the final judgment as to price. One participant in the August 17 hearing pointed out that the sentence dealt not with the determination of the costs to be recovered (this is determined by the power repayment studies) but rather the "allocation" of such cost recovery responsibility to the different units or classes of service.

The deletion of §903.5 moots this controversy. This deletion does not change the intent, however. As the Western Area Power Administration points out in its comments, cost of service is not dispositive for a Federal hydro-system where there are nonpower costs, such as irrigation assistance and desalinization plants, that were statutorily required to be repaid from power revenues and where there are no fuel costs. Also, in rate design, there are other factors to be considered than cost, such as conservation, efficient use of resources, equity, rate continuity, and ease of administration. However, revenue levels will continue to be established to recover costs, as required by law.

(3) Amortization Method

The statement issued with the proposed regulations in July 1979 contained the following explanation on the subject of amortization method:

"The provisions of the paragraph entitled 'Priority of Revenue Application,' 730 DM 4.5C(3), have been incorporated into §903.4(b), except that, in view of the review mentioned above, the following sentence has been omitted: 'To the extent possible, while still complying

with the repayment periods established for each increment of investment and unless otherwise indicated by legislation, amortization of the investment will be accomplished by application to the highest interest bearing investment first.' Although no change in the amortization practices will be made at this time, the omission of this sentence signifies that the subject is under review and that changes may be made following the conclusion of the ongoing study."

The omission of the quoted sentence received widespread criticism. Strong objections were voiced to any change in the present amortization method. The fear was expressed that because of the omission of the sentence, the Department would feel that it was free to go ahead and change the amortization method without affording an opportunity for public comment on any specific change that was under consideration.

The controversy over the omission of the sentence has served the purpose of alerting the customers to the fact that studies of alternative amortization methods are underway. We have decided to delete §903.4, setting forth cost recovery criteria; §903.10, requiring corrective action when studies show that revenues do not recover costs; and the references to power repayment studies, as these subjects are now covered by the Department of Energy guidelines in RA Order 6120.2. Section 8.c(3) of that order includes the same sentence that formerly was in 730 DM 4.5C(3) on the subject of amortizing the highest interest bearing investment first. The Department will not change that practice for any PMA without providing an opportunity for further public participation and comment.

(4) Information Procedures

A number of commenters questioned the adequacy of the opportunities provided in §903.14-16 for customers and other interested members of the public to obtain adequate information concerning the factual and policy basis for the proposed rates. Without this information meaningful and constructive comments would not be possible.

One suggestion was that the holding of at least one public information forum should be mandatory rather than optional. This is a reasonable recommendation and has been adopted for all major rate adjustments.

Another comment was that the public information forums are usually held too early in the comment period to permit meaningful questioning, because the supporting studies are so complex that it takes a long time to become familiar with them and the data and assumptions that are incorporated in them. For this reason, it was suggested that the public comment forum provide an opportunity for questioning of the Government official responsible for preparing these studies.

In general, there are two purposes to be served with respect to providing information about the proposed

rates. One is to acquaint the public generally with the magnitude of the rate increase and with the principal reasons for it. The other is to allow rate experts employed or retained by the customers or other interested parties to have access to the detailed data, assumptions and studies utilized in developing the rates. Sometimes the public information forums serve the first function, sometimes the second, and sometimes a combination of both. The first purpose suggests that the forum should be held early; the second, that it should be held later.

The forums are not the only opportunity provided the public to obtain information about the rate proposal. §903.14 states that the 90-day consultation period is to afford all interested persons "the opportunity to consult with and obtain information from the PMA" and "to examine backup data." §903.15(b) states that "questions that involve voluminous data contained in the PMA records may best be answered by providing an opportunity for consultation and for a review of the records at the PMA offices." In other words, the rate experts may obtain from staff all necessary backup data and may examine all relevant records. In some cases, arrangements have been made for the rate experts to have access to the PMA's computer program so they can run their own alternative computer studies. Members of the public who are not rate experts also are welcome to meet with PMA staff to learn more about the rate proposal.

In many cases the small informal arrangements for informing the customers of the need for and basis for the proposed rate increase, including meetings with the customers, have fully satisfied the customers so that a formal forum is unnecessary. The Southeastern Power Administration, for example, has been particularly successful in utilizing this informal approach. However, to avoid the possibility that a genuine need for an information forum might be overlooked, the regulations have been revised to require that at least one such forum will be held for a major rate adjustment. This may, however, be combined with the public comment forum held in accordance with §903.16. In other words, the one forum provides the opportunity of the PMA staff to explain the proposed rates, answer questions, and receive comments. Southeastern has done this with respect to its rate proceedings and has found that these meetings usually are brief, pro forma, and with very low attendance.

There are several reasons for holding the forum earlier in the process. One is to give the public a general understanding of the need for and the basis for the rate increase; another is to give the experts themselves a general understanding so that they know where to pursue further inquiries into the details. Lastly, as it may not be possible to answer some questions raised at the forum at the time, §903.15 provides that they shall be answered at a subsequent forum or in writing at least 15 days before the end of the consultation and comment period. If

the forum is held late in the process, this requirement to answer the questions might further and unnecessarily extend it. Also, the suggestion that the public comment forum be utilized as an opportunity to ask questions of persons who prepared the rate proposal leads to the dilemma that comments cannot always be made which are meaningful until after all questions are answered. By continually asking new questions at comment forums, the public participation process could be continued indefinitely.

In view of the variety of possible situations that might occur, and in the interest of giving the Administrator adequate flexibility, no minimum time period for holding the information forums has been written into the regulations. Normally, the forum will not be held until at least 30 days after the notice. The Administrator is always free to schedule additional forums upon request. In fact, this has happened on a number of occasions. The date for the second or continuation forum is usually discussed and announced at the first forum thus giving interested parties in attendance adequate notice.

Several commenters complained that the format of the public information forum would not allow for cross-examination because the opportunity to follow up an answer to the first question with a clarifying question generally is not available in open meetings with this format. For this, and other reasons, it was recommended that evidentiary or adjudicatory type hearings be required.

Contrary to the assumption of the suggestion, the public information forums have allowed follow up questioning similar to that which takes place under cross-examination. In the Central Valley Project rate proceedings, for example, one attorney spent many hours questioning the Government representatives. There have been two basic differences, however, between the forum and the normal evidentiary hearings before an administrative law judge. One is that the questions at the forums are addressed to a panel of Government witnesses, rather than just to one individual at a time. This has proven useful because no staff person is knowledgeable about all aspects of the repayment studies and rate design. On occasion, two or more members of the panel have disagreed among themselves as to the correct answer to a question. In such cases, and in cases where none of the members of the panel know the answer, the information is provided subsequently in writing, or at another forum, or, if it requires detailed data, the data is made available to the questioners and to others who might be interested.

The second difference is that the Chairman has interrupted the questioning by one person from time to time as convenient or appropriate, for example, to allow others to question who might not wish to stay for the whole session; or to take up questioning by all persons on each different topic as, for example, to take up all

questions dealing with hydrology, then all questions dealing with purchased power expenses, and so forth.

The normal process of an adjudicatory hearing by which one lawyer cross-examines one witness at a time without interruption, followed by redirect examination and re-cross-examination, can be time consuming and inefficient. The experience of the information forums which have been held since 1975 in ratemaking for the PMAs has proven successful and efficient, in our opinion, in bringing out all of the relevant factual and policy issues without unnecessary delay.

Another suggestion that was made is to add a requirement that the decision of the Assistant Secretary be made on the record of the proceeding developed through the transcripts of the public information and public comment forums, the answers to questions, and the written comments that were received. We believe such a limitation would be unnecessarily restrictive and would harm rather than facilitate proper decisionmaking.

Although the record developed in the proceeding will serve as the principal body of material upon which the decision of the Assistant Secretary is made, there is additional material which might be utilized in reaching this decision. One major category of such additional material is the backup data for the supporting studies. Both the PMA and the Assistant Secretary may wish to question and review some of this data even though it was not questioned by the public during the comment period. A second category is the up-to-date financial entries for the most recent fiscal year for the power system. Not infrequently, the comment period extends from one fiscal year to the next and new historical data is available before the decision is made. A third category of additional material is studies, information and ideas developed by departmental experts in response to comments that are filed during the course of the comment period. A fourth category is a significant event that is known to the public or to power rate experts which may not have been introduced or acknowledged in the record. For example, a flood occurs that causes major damage to a project powerplant; Congress passes legislation authorizing a new project; an appropriation act is passed which cuts back the appropriation for a project under construction to the point that it is evident that the in-service date of a key power plant will be delayed 1 or more years; a court issues an injunction suspending the construction of a major facility pending preparation of an environmental impact statement which, in turn, will delay the in-service date of a powerplant; or a new interest rate is required under RA 6120.2.11. Events of this kind may take place during the consultation and comment period, and prudent financial management would dictate that they be taken into consideration in making the final decision upon which the provisional rates are based.

(5) Role of the Administrator — Consultation

Several commenters suggested that the references in the proposed §903.12 to "consultation" by the Administrator

"with the Assistant Secretary, and through the Assistant Secretary with other departmental officials" before the Administrator develops Proposed Rates, and the reference in §903.17 to "consultation" by the Administrator with the Assistant Secretary before the Administrator develops Revised Proposed Rates, violate the mandate of Section 302(a) of the Department of Energy Organization Act, Public Law 95-91, that the rulemaking function shall be exercised by the Secretary "acting by and through" the Administrators. The argument is that the requirement for prior consultation defeats the intent of Congress that the rates will be developed to reflect regional needs and concerns and furthermore leads to the prospect that ratemaking policy will be set or at least heavily influenced by nameless individuals in Washington who will not be available for questioning at public information forums.

We believe that these concerns are exaggerated. Our interpretation of the Act is that Congress intended that the Secretary would exercise policy supervision over ratemaking but that all of the rate work and the original basic recommendations would be made by the Administrator reflecting the particular needs and concerns of the power systems and the interests of the region. This has been borne out in practice in the case of the 22 rate orders which were issued in the period from March 1, 1979, to July 1, 1980, pursuant to Delegation Order No. 0204-33. Nine of these rate orders approved rate increases, 12 were rate extensions, and one was a rate decrease. In some cases there was consultation between the Administrator and the Assistant Secretary prior to the announcement of a proposed rate or revised proposed rate and in some cases there was not.

In all cases there was consultation with the Assistant Secretary in the development of the rate order. As it turned out, contrary to earlier expectations, there was virtually no consultation on individual rate cases with the Administrator of the Economic Regulatory Administration or the Assistant Secretary for Policy and Evaluation. This occurred in large part because ratemaking for the PMAs is highly specialized and complex and bears little relationship to ratemaking for regulated utilities.

Because of our decision to eliminate provisions relating to rate design, cost recovery criteria, and power repayment studies, we have eliminated §903.12. In doing so, however, policy consultation between the Assistant Secretary and each Administrator will continue at various steps of the ratemaking process as appropriate and that the Assistant Secretary will consult with other policy persons in the Department if special occasions arise where this is appropriate. These consultative processes, however, are internal, and do not need to be spelled out in these procedures. Any such consultations do not detract from the requirement in §903.21 that a statement shall be issued explaining the principal factors leading to the Assistant Secretary's decision. Other

DOE offices have the option of submitting comments in response to the advance announcement, §903.11; or during the consultation and comment period, §903.14.

§903.12 as originally proposed included the description of certain supporting statements A through E which we anticipated would be required by the FERC when rates were approved by the Assistant Secretary for Resource Applications on an interim basis and submitted to the FERC for approval on a final basis. Detailed requirements concerning these statement have not been finally determined. They may be included in future regulations by the FERC.

(6) Need for Common Procedures

The proposal to establish common procedures for all five PMAs was both praised and condemned on the grounds that it might restrict the flexibility of the Administrators to respond to regional concerns. We do not believe this will be a problem for the four PMAs to which these procedures apply because the procedures have been drafted to provide maximum flexibility. Bonneville has been excluded because of the unique procedural provisions in the Pacific Northwest Electric Power Planning and Conservation Act.

Any drawback of this kind is outweighed by the advantage to be gained from establishing standard terminology and standard steps in the ratemaking process. This will facilitate the ability of the public to understand and to make input to rate development and will facilitate the review by the FERC in the exercise of its responsibilities under Delegation Order No. 0204-33.

(7) Minor Rate Adjustments; Rates for minor new services

§903.23 of the proposed regulations waived the notice and comment requirements for rate adjustments designated as "minor," for extensions of existing rates, and for certain rates for "new services." This received considerable criticism. In response to these comments, the regulations adopted herewith include definitions of "new service," "minor new service," and "major rate adjustment," revise the definition of "minor rate adjustment," and eliminate the waiver of all notice and comment requirements; but substitute a requirement for 30 days' notice for minor rate cases, with the holding of forums optional. The distinctions between minor and major rate adjustment procedures have been incorporated in §903.14-16.

III. Section-by-Section Commentary

Title

It was suggested that the title of these regulations be expanded to include reference to rate standards or criteria because of the inclusion of §903.4 on cost recovery and §903.5 on rate design. We recognize that this was a valid suggestion, but it has been rendered unnecessary because the two sections have been deleted.

In view of the fact that the shortened procedures deal almost entirely with the subject of "public participation," we have added those words to the title.

Authority

Western has recommended that the citations to the authority for the regulations be amended to include a reference to Section 9 of the Flood Control Act of 1944. Section 9 authorizes the Pick-Sloan Missouri Basin Program. Thus, it is only one of hundreds of laws which authorizes or otherwise relates to individual projects or power systems. To cite them individually would be a major undertaking. Instead they are now referred to generally under the last phrase "the acts specifically applicable to individual projects or power systems."

§903.1 — Applications

There were several objections to the provision in §903.1(b) authorizing the Administrators to apply these new procedures to pending rate adjustment proceedings. Another comment was that the decision as to whether they should be applied to proceedings should be made by the Assistant Secretary, not by the Administrator.

The new procedures eliminate the requirement applicable only under Western procedures that the proposed decision of the Assistant Secretary be published for a final round of comments before the Assistant Secretary issues a rate order approving rates on an interim basis. To avoid controversy over the objections raised, the provision authorizing the Administrator to apply the new procedures to pending proceedings has been eliminated.

These procedures will supersede those published by Western entirely, and will supersede those published by Southeastern only insofar as those published procedures apply to rate adjustments. They shall become effective immediately except that they will not apply to rate adjustments that have already been announced as required by §903.13.

§903.2 — Definitions

New Service. A new definition has been added for a "new service." It is defined as "service not previously provided." The term "new service" was used in connection with §903.23 of the proposed procedures, which waived all public comment requirements for "rates for a new project or system or rates for a new service." The fear was expressed by several commenters that this would permit a loophole under which existing services would be simply covered by a new rate. This was not the intent, and the new definition would prevent this.

Minor new service. A new definition has been added for a "minor new service," which is included in the definition of a minor rate adjustment. The new definition is employed to describe various situations in which simplified rate procedures may be utilized. Four different situations are described. The first is for a rate for a new service which will produce less than a one percent change in the annual revenues of the power system. Examples include

rates for the provision of emergency service as part of a power pool or a rate for the sale of reserves or standby service.

The second is rates for a new power system which has either annual sales normally less than 100 million kilowatthours or an installed capacity of less than 20,000 kilowatts. It is anticipated that a number of these new power systems may be established as the Army Corps of Engineers or the Water and Power Resources Service install small powerplants at existing Federal dams or at undeveloped sites.

Third, there are services which will not be provided for more than one year. An example is the special contract rate of the Bonneville Power Administration for the sale of withdrawn Hanford energy during the period January 1, 1978, through June 30, 1978, which was approved by order of the ERA and published in the *Federal Register* on October 3, 1978 (43 FR 45630).

The fourth is for the temporary disposition of the output of a new powerplant for not more than one year. An example of this is the rate for the short-term sales of the output of the Laurel Project, Kentucky, which was approved by an order by the ERA, published on April 26, 1978 (43 FR 17857), and extended by ERA orders published on June 15, 1978 (43 FR 25856), September 26, 1978, (43 FR 43547), and January 15, 1979 (44 FR 1445), and by a FERC order published on September 4, 1979 (44 FR 51654).

Minor rate adjustment. The definition of a "minor rate adjustment" has been revised to exclude the continuation of an existing rate, because this is now covered in §903.23 by use of the term "rate extensions," and to add two other conditions which qualify a rate as a minor rate adjustment. These are (1) a rate adjustment for a power system which has either annual sales normally less than 100 million kilowatthours or an installed capacity less than 20,000 kilowatts, or (2) is a rate for a minor new service. The addition numbered (1) above was recommended by Western to take care of the situation of a possible adjustment in the rate for a small project which has a minor impact relative to the overall area power supply.

Major rate adjustment. A new definition has been added for a "major rate adjustment." It is defined as "a rate adjustment other than a minor rate adjustment." The new term is used in connection with §903.14 to make a 90-day consultation and comment period applicable only to major rate adjustments, whereas, a shorter time period of 30 days would be applicable to minor rate adjustments.

Also, the term is used in connection with §903.15 and §903.16 to make public information and public comment forums mandatory for major rate adjustments, but optional for minor rate adjustments.

Power system. The term "project or system" utilized in the proposed regulations to denote the operating unit to which the rate applies is cumbersome and confusing. The term "power system" has been substituted. This phrase

was used in 730 DM 4 and has been continued in RA 6120.2. The change leads to the desirable result that the same term "power system" is used both in the published procedures and in these internal Department of Energy policy guidelines. For clarity, the definition has been modified slightly from that used in RA 6120.2.

Rate adjustment. The definition of "Rate adjustment" has been revised to clarify that it does not include changes in the monetary charge made pursuant to a formula stated in a rate schedule or contract. Some examples are, certain generating charges, fuel replacement sales, purchased power passthrough, and transmission service over a joint transmission system where charges vary as operation and maintenance costs change.

Rate terms. One suggestion was that the use of the terms "Revised Proposed Rate," "Substitute Rate," and "Proposed Substitute Rate" be deleted as unnecessary. The term "Revised Proposed Rate" was recommended by Bonneville to distinguish the proposal coming after the conclusion of the initial public comment period from the proposal at the beginning of that period. This term was utilized by Bonneville in connection with its public comment process which ran for almost a year from August 1978 to August 1979 and has proven to be useful. The term "Substitute Rate" is useful in drafting the regulations to identify a rate which is being put into effect following FERC disapproval of a provisional rate. It is a term that is used in Delegation Order 0204-33. The term "Proposed Substitute Rate" is useful for drafting purposes to denote a proposed rate which responds to FERC disapproval of a provisional rate and which is under consideration while a provisional rate is still in effect.

The heading for former subsection (1) on "Rate definitions" has been changed to "Rate types."

The word [words-Ed.] "by the Assistant Secretary" have been inserted after "submitted" in the definition of "Substitute Rate" for clarification.

One commenter suggested that "rates" be defined the way the FERC defines the term. The FERC definition of "rate schedule" is far too broad for use in these procedures. It covers all classifications, practices, rules, regulations or contracts which in any manner affect or relate to electric service. Use of so broad a definition would require submission to the FERC of matters relating to power and transmission operations and contracts which are reserved by Section 302(a) of the Department of Energy Organization Act to the PMAs. It was not the intent of the delegation order that the FERC review these matters. The review is limited to the monetary charges, as indicated in the definition that is used.

Definitions deleted. The definitions of "power repayment study" and "rate design" have been eliminated.

§903.11 — Advance Announcement of Rate Adjustment

This section provides that the Administrator may give advance notice of his determination that new or revised

rates are under consideration and give the public an opportunity to submit advance comments on the rate adjustment process. Several commenters suggested that the announcement should be made mandatory rather than permissive so that public involvement will always occur prior to the Administrator's notice of proposed rates. This suggestion has not been adopted in order to provide greater flexibility and to reduce the time needed in appropriate cases to place revised rates into effect. The PMAs are in regular communication with their customers and are able to judge whether there is sufficient controversy to justify an advance announcement.

A sentence was added to require consideration of any comments received.

§903.13 — *Notice of Proposed Rates*

It was suggested that to minimize delays, the Administrator should be required to mail copies of all relevant studies to customers at the time notice of proposed rates is given rather than to mail such material upon request. This will be done in most cases, particularly where the customers have previously expressed an interest in rates and ratemaking, but we do not believe it is wise to require it in every case. This could be unnecessarily cumbersome where there are a large number of customers who do not have an interest in detailed rate studies.

Another suggestion was that customers be allowed access to the data base, including computer programs used to prepare the current and revised power repayment studies, Statements A through E, and the rate design study, on reasonable terms and conditions at the time the proposed rate increase is noticed in the *Federal Register*. The PMAs have made and will continue to make backup data available to any interested customer or other person upon request at reasonable times and in a reasonable manner. This is consistent with §903.14; thus, resort to the formalities of the Freedom of Information Act is not necessary.

Subsection (a) has been revised to require that the Notice contain an explanation of the need for and derivation of the Proposed Rates. Subsection (b) has been revised to eliminate the references to specific studies and statements because the provisions relating to these studies and statements have been deleted. Upon request, customers or interested persons will be furnished the principle documents used in developing the Proposed Rates.

§903.14 — *Consultation and Comment Period*

Several commenters suggested that the minimum of 90 days for the consultation and comment period be increased to 180 days, arguing that 90 days is too short a time to enable effective examination by customers of voluminous repayment studies and rate design studies and the backup data. The experience to date has been that when customers have requested more time and have had good reason for their requests, the extension has been granted. We are reluctant to extend the minimum

for all cases because experience has shown that 90 days is ample for most rate adjustments.

It was suggested that this section be revised to require the Administrators to prepare and circulate a service list of all interested parties to the rate proceedings to assure that each person commenting knows what the others have said. This suggestion reflects what has been done in actual practice in some cases. A sentence has been added to the section requiring the Administrator to maintain, and distribute upon request, a list of interested persons. This list is not called a "service list" because this is not an adversary proceeding similar to the normal evidentiary or adjudicatory proceeding before an administrative law judge. Also, a requirement for formal intervention has not been included, nor a requirement that each person submitting comments send copies to everyone else on the list, because such requirements would make the proceedings unnecessarily formal and might discourage some persons with a legitimate interest in the proceedings from participation.

Another suggestion was that a 90-day pre-Federal Register notice to customers be required to allow a knowledgeable exchange of information on an informal basis. Under §903.11 dealing with the advance announcement, we feel that the Administrator has discretion to allow sufficient time for exchange of information and ideas with the customers and other interested parties.

This subsection was revised to require a 90-day consultation and comment period for major rate adjustments and a 30-day consultation and comment period for minor rate adjustments.

§903.15 — *Public Information Forum(s)*

Comments relating to the conduct of the information forums, including recommendations that they be adjudicatory-type hearings with the right of formal cross-examination are discussed under II(4) above. As stated therein, the section has been revised to require that at least one public information forum be held.

Subsection 903.15(a) was revised to make public information forums mandatory for major rate adjustments, but optional for minor rate adjustments.

§903.16 — *Public Comment Forum(s)*

Comments relating to the conduct of public comments forums also are discussed under II(4) above.

Subsection 903.16(a) was revised to make public comment forums mandatory for major rate adjustments, but optional for minor rate adjustments.

§903.17 — *Revised Proposed Rates*

The reference to consultation with the Assistant Secretary has been deleted for the reasons explained under II(5) above.

§903.21 — *Provisional Rates*

The suggestion that the decision should be made on the basis of the record is discussed under II(4) above.

Several commenters questioned the statement in subsection (a) that "The Administrator shall develop rates which, in the Assistant Secretary's judgment, should be confirmed, approved, and placed in effect on an interim basis," on the grounds that this violates the Administrator's statutory authority and responsibility to propose rates. This does not follow. At this state of the proceedings, it is necessary for the Assistant Secretary to exercise the function of policy supervision of ratemaking by approving a rate which is deemed acceptable. Inasmuch as the Assistant Secretary does not have the rate staff, the basic data or the computer capability necessary to develop rates, the rate work itself must be done by the PMA.

One commenter expressed opposition to implementation of provisional rates in every case prior to independent review by the FERC. Instead, it was suggested that the Administrator's proposed rates only go into effect after the FERC's approval. The experience of the last year shows that the FERC may take a relatively long time before approving rate increases on an [a-Ed.] final basis. It would place the financial position of most power systems in jeopardy if revenues from increased rates could not be collected during this delayed period on an interim basis. The customers are protected by the provisions for refunds of any overpayment with interest if the rate finally approved by the FERC is lower than the provisional rate. The Assistant Secretary retains the option to have the rate go into effect upon final approval by the FERC.

§903.22 — *Final Rate Approval*

The comments indicate that the refund provisions under the delegation order and under these regulations are confusing. A new subsection (f) has been added to help eliminate this confusion.

§903.23 — *Rate extensions*

A separate section is included in the regulations to explain how rate extensions are handled. In the proposed regulations, rate extensions were included in the definition of minor rate adjustments, but this led to confusion.

Basically, it is anticipated that rate extensions will fall into three categories. One category would include provisional rates for power systems approved by the Assistant Secretary for Resource Applications on an interim basis for a fixed period and not expected to be approved or disapproved by the FERC within the fixed period. Thus, it becomes necessary to extend the interim approval of provisional rates to give the FERC additional time to act on the original rate approval by the Assistant Secretary for Resource Applications. A second category would be rates for power systems which require a rate adjustment to be in compliance with repayment criteria, but for any one or more of several reasons,

revised rates have not been developed which will be approved by the Assistant Secretary for Resource Applications prior to the expiration of the approval of the existing rates. A third category of rate extension would be rates for power systems which do not need a rate adjustment to be in compliance with repayment criteria.

For a rate extension previously confirmed and approved by the FERC or prior authority, a 30-day notice is required unless shortened for good cause, the consultation and comment period shall be as provided in §903.14, and public forums may be held as provided in §903.15-16. Rate extensions shall be governed by §903.21(d) and §903.22.

Provisional rates may be extended by the Assistant Secretary for Resource Applications without advance notice or comment. Notice of such action shall be published in the *Federal Register*.

Entities who commented

Listed below are the parties that submitted comments in response to the proposed procedures published in the *Federal Register* on July 5, 1979 (44 FR 39184), and those that presented comments at hearings held in Washington, D.C., on July 27 and August 17, 1979:

- *1. American Public Power Association (APPA)
2. Eugene Water and Electric Board, Oregon
3. City of Tacoma, Washington
4. Intercompany Pool Companies, Seattle, Washington
5. Public Power Council, Vancouver, Washington
6. Public Utility District of Clark County, Vancouver, Washington
- *7. Missouri Basin Municipal Power Agency
8. Municipal Electric Authority of Georgia
9. Plains Electric Generation & Transmission Cooperative, Inc., New Mexico
10. City of Doerun, Georgia
11. City of East Point, Georgia
12. City of Barnesville, Georgia
13. City of Thomasville, Georgia
14. City of Griffin, Georgia
15. Big Rivers Electric Corporation, Southern Illinois Power Cooperative, East Kentucky Power Cooperative, & Hoosier Energy Corporation
16. Fitzgerald Water, Light & Bond Commission, Georgia
17. City of Douglas, Georgia
18. City of Moultrie, Georgia
19. Electric Cities of Georgia
20. Tri-State Generation & Transmission Association, Inc.
21. Irrigation & Electrical Districts Association of Arizona (IEDA)
22. San Diego Gas & Electric
23. Northern California Power Agency
24. Intermountain Rural Electric Association, Inc. (IREA)

- 25. National Rural Electric Cooperative Association (NRECA)
- 26. Committee on Power for the Southwest, Inc., Tulsa, Oklahoma
- 27. East River Electric Power Cooperative, Inc.
- 28. Irrigation Districts, Central Valley Project, California
- 29. Intermountain Consumer Power Association (ICPA), Utah
- 30. City of Page, Arizona
- 31. Arizona Power Authority
- 32. Basin Electric Power Cooperative, North Dakota
- 33. Bureau of Reclamation, Department of the Interior
- *34. Mid-West Electric Consumers Association, Inc.
- *35. Department of Water and Power of the City of Los Angeles
- 36. California Energy Commission
- 37. Western Area Power Administration
- *38. Arizona Municipal Power Users' Association (AMPUA)

- *39. Enerjoules Limited, Mukilteo, Washington
- *40. Colorado River Energy Distribution Association, Inc. (CREDA) and Salt River Project Agricultural Improvement and Power District (Salt River)
- *41. R.W. Allin, Oak Harbor, Washington
- *Comments received during hearings on July 27 and August 17, 1979.

In view of the foregoing, the Department of Energy hereby adds a new Part 903 to Title 10, Code of Federal Regulations entitled "Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions" as set forth below:

Issued in Washington, DC December 23, 1980.

Ruth M. Davis
Assistant Secretary
Resource Applications

The Department of Energy hereby adds Subpart A of Part 903 to Title 10, Code of Federal Regulations as set forth below:

Part 903 — POWER AND TRANSMISSION RATES

Subpart A — Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions for the Alaska, Southeastern, Southwestern, and Western Area Power Administrations

Sec.

- 903.1 Purpose and scope; Application
- 903.2 Definitions
- 903.11 Advance announcement of rate adjustment
- 903.13 Notice of Proposed Rates
- 903.14 Consultation and comment period
- 903.15 Public information forum(s)
- 903.16 Public comment forum(s)
- 903.17 Revised Proposed Rates
- 903.21 Provisional Rates
- 903.22 Final rate approval
- 903.23 Rate extensions

Authority: Sections 301(b), 302(a), and 644 of Department of Energy Organization Act P.L. 95-91, (42 U.S.C. 7101 *et seq.*); Section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s); the Reclamation Act of 1902 (43 U.S.C. 372 *et seq.*), as amended and supplemented by subsequent enactments, particularly Section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)); and the acts specifically applicable to individual projects or power systems.

§903.1 Purpose and scope; Application

(a) These regulations establish procedures for the development, and for the confirmation and approval on an interim basis by the Assistant Secretary for Resource Applications, of new, revised, or extended power and transmission rates of the Alaska Power Administration, the Southeastern Power Administration, the Southwestern Power Administration, and the Western Area Power Administration, and opportunities for interested members of the public to participate in the development of such rates. These regulations supplement Delegation Order No. 0204-33 dated December 21, 1978, of the Secretary of Energy, effective January 1, 1979, which was published in the *Federal Register* on December 28, 1978 (43 F.R. 60636), with respect to the activities of the Assistant Secretary for Resource Applications and the Power Marketing Administrators.

(b) These regulations shall apply to all power and transmission rate adjustment proceedings for the four power marketing administrations which are commenced after December 31, 1980. Thus, for all new rate proceedings they supersede the informal practices followed by the Alaska and Southwestern Power Administrations and supersede the following published regulations only as they apply to rate adjustments: (1) for the Southeastern Power Administration, the "Procedure for Public Par-

ticipation in the Formulation of Marketing Policy," 43 F.R. 29186 (July 6, 1978); and (2) for the Western Area Power Administration, the "Procedures for Public Participation in General Adjustments in Rates for Power Marketed by the Western Area Power Administration," 43 F.R. 12076 (March 23, 1978), as amended by 44 F.R. 7796 (February 7, 1979).

§903.2 Definitions

As used herein—

(a) "Administrator" means the Administrator of the Power Marketing Administration (PMA) whose rate is involved in the rate adjustment, or anyone acting in such capacity.

(b) "Assistant Secretary" means the Assistant Secretary for Resource Applications of the Department, or anyone acting in such capacity.

(c) "Department" means the Department of Energy including the PMAs and excluding the Federal Energy Regulatory Commission.

(d) "FERC" means the Federal Energy Regulatory Commission.

(e) "Major rate adjustment" means a rate adjustment other than a minor rate adjustment.

(f) "Minor new service" means a new service which (1) will produce less than a 1 percent change in the annual revenues of the power system, or (2) is for a new power system which has either annual sales normally less than 100 million kilowatthours or an installed capacity of less than 20,000 kilowatts, or (3) will not be provided for more than one year, or (4) is for the temporary disposition, for not more than one year, of the output of a new powerplant.

(g) "Minor rate adjustment" means a rate adjustment which (1) will produce less than a 1 percent change in the annual revenues of the power system, or (2) is for a power system which has either annual sales normally less than 100 million kilowatthours or an installed capacity of less than 20,000 kilowatts, or (3) is a rate for a minor new service.

(h) "New service" means a service not previously provided. The term includes, but is not limited to, service from a new powerplant, where this is sold under a separate rates or service from a new power system.

(i) "Notice" means the statement which informs customers and the general public of Proposed Rates, Revised Proposed Rates, Proposed Substitute Rates, rate extensions or proposed rate extensions, opportunities for consultation and comment, rate extensions, opportunities for consultation and comment, and public information and public comment forums. The Notice shall be by and effective on the date of publication in the *Federal Register*. Whenever a time period is provided, the date of publication in the *Federal Register* shall

determine the commencement of the time period, unless otherwise provided in the Notice. The Notice shall include the name, address, and telephone number of the person to contact if participation or further information is sought.

(j) "Power Marketing Administration" or "PMA" means Alaska Power Administration (APA), Southeastern Power Administration (SEPA), Southwestern Power Administration (SWPA), Western Area Power Administration (WAPA), or such additional PMAs as may be created to administer power marketing functions of the Department.

(k) "Power system" means a powerplant or a group of powerplants and related facilities, including transmission facilities or a transmission system, that the PMA treats as one unit for the purpose of establishing rates and demonstrating repayment.

(l) "Rate" means the monetary charge or the formula for computing such a charge for any electric service provided by the PMA, including but not limited to charges for capacity (or demand), energy, or transmission service, and discounts or surcharges; however, it does not include leasing fees, service facility charges, or other types of facility use charges. A rate may be set forth in a rate schedule or in a contract.

(m) "Rate adjustment" means a change in an existing rate or rates, or the establishment of a rate or rates for a new service. It does not include a change in rate schedule provisions or in contract terms, if such change does not involve a change in the price per unit of service, nor does it include changes in the monetary charge pursuant to a formula stated in a rate schedule or a contract.

(n) "Rate schedule" means a document identified as a "rate schedule," "schedule of rates" or "schedule rate" which designates the rate or rates applicable to a class of service specified therein and may contain other terms and conditions relating to the service.

(o) Rate types:

(1) "Proposed Rate" means a rate revision or a rate for a new service which is under consideration by the Department on which public comment is invited.

(2) "Revised Proposed Rate" means a revision of a Proposed Rate on which, in the Administrator's judgment, further public comment should be invited.

(3) "Provisional Rate" means a rate that has been confirmed and approved on an interim basis by the Assistant Secretary.

(4) "Proposed Substitute Rate" means a proposed substitute for a Provisional Rate that has been disapproved by the FERC on which, in the Administrator's judgment, further public comment should be invited.

(5) "Substitute Rate" means a rate submitted by the Assistant Secretary to the FERC as a proposed substitute for a Provisional Rate or a previous Substitute

Rate that has been disapproved by the FERC.

§903.11 *Advance announcement of rate adjustment*

The Administrator may announce that the development of rates for a new service or revised rates for an existing service is under consideration. The announcement shall (1) specify the rates which are to be developed or revised, and (2) contain any other pertinent information relevant to the rate adjustment process. The announcement may be through direct contact with customers, at public meetings, by press release, by newspaper advertisement, and/or *Federal Register* publication. Written comments relevant to rate policy and design and to the rate adjustment process may be submitted by interested parties in response to the announcement. Any comments received shall be considered in the development of Proposed Rates.

§903.13 *Notice of Proposed Rates*

(a) The Administrator shall give Notice that Proposed Rates have been prepared and are under consideration. The Notice shall include:

(1) the Proposed Rates;

(2) an explanation of the need for and derivation of the Proposed Rates;

(3) the location(s) at which data, studies, reports or other documents used in developing the Proposed Rates are available for inspection and/or copying;

(4) the date(s), time(s) and location(s) of any initially scheduled public information and comment forum(s); and

(5) addresses to which written comments relative to the Proposed Rates may be submitted.

(b) Upon request, customers of the power system and other interested persons will be provided with copies of the principal documents used in developing the Proposed Rates.

§903.14 *Consultation and comment period*

All interested persons will have the opportunity to consult with and obtain information from the PMA, to examine back-up data, and to make suggestions for modification of the Proposed Rates for a period ending (1) 90 days, in the case of major rate adjustments, or 30 days in the case of minor rate adjustments, after the Notice of Proposed Rates is published in the *Federal Register*, except that such periods may be shortened for good cause shown; (2) 15 days after written answer is provided pursuant to §903.15(b); (3) 15 days after the close of the (last) public comment forum described in §903.16 below; or (4) such other time as the Administrator may designate; whichever is later. At any time during this period, interested persons may submit written comments to the PMA regarding the Proposed Rates. The Administrator may also provide additional time for the submission of written rebuttal comments. All written comments shall be available at a designated

location for inspection, and copies also will be furnished on request for which the Administrator may assess a fee. Prior to the action described in §903.21, the Administrator may by appropriate announcement postpone any procedural date or make other procedural changes for good cause shown at the request of any party or on the Administrator's own motion. The Administrator shall maintain, and distribute on request, a list of interested persons.

§903.15 *Public information forum(s)*

(a) One or more public information forums shall be held for major rate adjustments and may be held for minor rate adjustments, to explain, and to answer questions concerning, the Proposed Rates and the basis of and justification for proposing such rates. The number, date(s), and location(s) of such forum(s) will be determined by the Administrator in accordance with the anticipated or demonstrated interest in the Proposed Rates. Notice shall be given in advance of such forum(s) and shall include the purpose, date, time, place, and procedures for such forum(s). A public information forum may be combined with a public comment forum held in accordance with §903.16.

(b) The Administrator shall appoint a forum chairperson. Questions raised at the forum concerning the Proposed Rates and the studies shall be answered by PMA representatives at the forum, at a subsequent forum or in writing at least 15 days before the end of the consultation and comment period. However, questions that involve voluminous data contained in the PMA records may best be answered by providing an opportunity for consultation and for a review of the records at the PMA offices. As a minimum, the proceedings of the forum(s) held at one principal location shall be transcribed. Copies of all documents introduced, and of questions and written answers shall be available at a designated location for inspection and copies will be furnished by the Administrator on request for which a fee may be assessed. Copies of the transcript may be obtained from the transcribing service.

§903.16 *Public comment forum(s)*

(a) One or more public comment forums shall be held for major rate adjustments and may be held for minor rate adjustments, to provide interested persons an opportunity for oral presentation of views, data, and arguments regarding the Proposed Rates. The number, date(s), and location(s) of such forum(s) will be determined by the Administrator in accordance with the anticipated or demonstrated interest in the Proposed Rates. Notice shall be given at least 30 days in advance of the first forum at each location and shall include the purpose, date, time, place, and other information relevant to the forum, as well as the locations where pertinent documents are available for examination and/or copying.

(b) The Administrator shall designate a forum chairperson. At the forum, PMA representatives may question those persons making oral statements and com-

ments. The chairperson shall have discretion to establish the sequence of and time limits for oral presentations and to determine if the comments are relevant and non-cumulative. Forum proceedings shall be transcribed. Copies of all documents introduced shall be available at a designated location for inspection, and copies shall be furnished on request for which the Administrator may assess a fee. Copies of the transcript may be obtained from the transcribing service.

§903.17 *Revised Proposed Rates*

During or after the consultation and comment period and review of the oral and written comments on the Proposed Rates, the Administrator may develop Revised Proposed Rates upon which, in the Administrator's judgment, further public comment should be invited. In such a case, the Administrator shall afford interested persons at least 30 days to submit further written comments to the PMA regarding the Revised Proposed Rates and may convene one or more additional public information and/or public comment forums. The Administrator shall give Notice of any such additional forums and opportunity to submit written comments.

§903.21 *Provisional Rates*

(a) Following completion of the consultation and comment period and review of any oral and written comments on the Proposed Rates, or Revised Proposed Rates, the Administrator shall develop rates which, in the Assistant Secretary's judgment, should be confirmed, approved, and placed in effect on an interim basis. A statement shall be prepared and made available to the public of the principal factors on which the Assistant Secretary's decision was based. It shall include an explanation responding to the major comments, criticisms, and alternatives offered during the comment period.

(b) The Assistant Secretary shall set the effective date for the rates he or she has confirmed and approved on an interim basis (Provisional Rates). The effective date shall be at least 30 days after the Assistant Secretary's decision, except that the effective date may be sooner when appropriate to meet a contract deadline, to avoid financial difficulties, to provide a rate for a new service, or to make a minor rate adjustment.

(c) The effective date of the Provisional Rates for the purpose of billing may be adjusted by the Administrator to coincide with the beginning of the next billing period following the date set by the Assistant Secretary.

(d) The Provisional Rates shall remain in effect until (1) they are confirmed and approved on a final basis by the FERC under §903.22(b), (2) the rates last previously confirmed and approved on a final basis become effective under §903.22(d), (3) higher Substitute Rates are confirmed and approved on a final basis and placed in effect by the FERC under §903.22(e), (4) lower Substitute Rates are confirmed and approved on a final basis by the FERC under §903.22(f), or (5) they are super-

seded by other Provisional Rates placed in effect by the Assistant Secretary, whichever occurs first.

§903.22 *Final rate approval*

(a) Following confirmation and approval of rates on an interim basis, the Provisional Rates shall be submitted promptly to the FERC for confirmation and approval on a final basis, together with such supporting data, studies and documents as the FERC may require, transcripts of forums, written answers to questions, written comments, and the statement of principal factors leading to the Assistant Secretary's decision. A listing of current customers and other participants in the rate proceeding also shall be furnished.

(b) If the FERC confirms and approves Provisional Rates on a final basis, such confirmation and approval shall be effective as of the date such rates were placed in effect by the Assistant Secretary.

(c) In the event Provisional Rates or Substitute Rates are disapproved by the FERC, the Assistant Secretary shall develop, acting by and through the Administrator, and submit to the FERC Substitute Rates which take into consideration the reasons given by the FERC for its disapproval. A statement explaining the Assistant Secretary's decision shall accompany the submission. Prior to such submission, the Assistant Secretary and the Administrator may develop Proposed Substitute Rates on which, in the Administrator's judgment, further public comment should be invited, in which case the Administrator shall afford interested persons at least 30 days to submit written comments to the PMA and may convene one or more additional public information and/or public comment forums. The Administrator shall give Notice of any such additional forums and opportunity to submit written comments.

(d) A Provisional Rate that is disapproved by the FERC shall remain in effect, until one of the events described in §903.21(d) (3), (4) or (5) occurs; *Provided*, that if the Assistant Secretary does not file a Substitute Rate within 120 days of the disapproval or such greater time as the FERC may provide, and if the rate has been disapproved because the FERC determined that it would result in total revenues in excess of those required by law, the rate last previously confirmed and approved on a final basis will become effective on a date and for a period determined by the FERC and revenues collected in excess of such rate during the interim period will be refunded with interest to the extent determined by the FERC.

(e) If a Substitute Rate confirmed and approved on a final basis by the FERC is higher than the rate in effect on an interim basis, such higher rate shall become effective on a subsequent date set by the FERC.

(f) In the case where a Substitute Rate confirmed and approved by the FERC on a final basis is lower than the rate in effect on an interim basis, such lower rate shall become effective as of the date the higher rate was placed in effect on an interim basis by the Assistant Secretary, and the amount of the refund will be the overpayment on all transactions, that is, the difference between the amount paid for the transaction and the amount that would have been paid under the Substitute Rate, unless the FERC determines that there will be no refund because the administrative cost of a refund would exceed the amount to be refunded. In the case covered by the proviso in subsection (d) the amount of the refund is determined by the FERC. In both cases, the amount of the interest on the refund will be determined by the FERC.

(g) A rate confirmed and approved by the FERC on a final basis shall remain in effect for such period or periods as the FERC may provide or until the Assistant Secretary places a new Provisional Rate into effect; *Provided*, That the Assistant Secretary may extend the rate on an interim basis beyond the period specified by the FERC as provided in §903.23.

§903.23 *Rate extensions*

(a) The following regulations shall apply to the extension of rates which were previously confirmed and approved by the FERC, the Federal Power Commission or the Administrator of the Economic Regulatory Administration, or established by the Secretary of the Interior:

(1) The Administrator shall give Notice of the proposed extension at least 30 days before the expiration of the prior confirmation and approval, except that such period may be shortened for good cause shown.

(2) The Administrator shall allow for consultation and comment, as provided in §903.14, for such period as he or she may provide. One or more public information and comment forum(s) may be held, as provided in §903.15 and §903.16, at such time(s) and location(s) and with such advance notice as the Administrator may provide.

(3) Following the conclusion of the consultation and comment period, the Assistant Secretary may extend the rates on an interim basis. Such extension shall be governed by §903.21(d) and §903.22.

(b) Provisional Rates may be extended by the Assistant Secretary without advance notice or comment. The Assistant Secretary shall publish notice in the *Federal Register* of such extension and shall promptly advise the FERC of the extension.

DEPARTMENT OF ENERGY

10 CFR PART 903

Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions; Corrections

AGENCY: Department of Energy, Resource Applications

ACTION: Corrections to Final regulations

SUMMARY: Notice is given of Minor clarifying corrections to the Final regulations as published in the Federal Register on December 31, 1980 (45 FR 86976).

DATE: The corrections to the regulations are effective December 31, 1980.

FOR FURTHER INFORMATION CONTACT:

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Washington, DC 20585 (202) 252-2918

SUPPLEMENTARY INFORMATION:

The corrections are as follows:

Preamble

1. Page 86977 — First column:

In the penultimate paragraph, change the date of "December 31, 1981," to "December 31, 1980."

Regulations

2. Page 86983 — Third column:

In §903.1(b), fifth and sixth lines, delete "these regulations become effective" and insert "December 31, 1980".

3. Page 86984 — First column:

a. In §903.2(e), first line, change "Major adjustment" to "Major rate adjustment".

b. In subsection (j), third and forth lines, delete "Bonneville Power Administration (BPA).".

4. Page 86984 — Third column:

a. In §903.13(4), third line, change "comment forum;" to "comment forum(s);"

b. In §903.14, eighteenth line, which reads "other time as the administrator may," capitalize the first letter of the word "Administrator".

5. Page 86985 — Third column:

In §903.21(d), eighth line, which now reads "are confirmed and approved and placed", change to "are

confirmed and approved on a final basis and placed".

6. Page 86986 — Second column:

In §903.23(b), at the end, delete "Q02". This symbol was added by the printer when published in the Federal Register.

Issued in Washington, D.C., January 16, 1981.

Ruth M. Davis

Assistant Secretary, Resource Applications.

DEPARTMENT OF ENERGY

10 CFR PART 903

Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions

AGENCY: Department of Energy.

ACTION: Amendment to final rule.

SUMMARY: Notice is given that the Department of Energy is amending its regulations on "procedures for public participation in power and transmission rate adjustments and extensions" (45 FR 86976, Dec. 31, 1980) in order to change all references from "Assistant Secretary for Resource Applications" to "Assistant Secretary for Conservation and Renewable Energy." The amendment is necessary as a result of the transfer on February 24, 1981, of the Office of Power Marketing Coordination and the power marketing administrations from the Assistant Secretary for Resource Applications to the Assistant Secretary for Conservation and Renewable Energy.

DATE: This amendment is effective as of February 24, 1981.

FOR FURTHER INFORMATION CONTACT:

James A. Braxdale, Office of Power
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(202) 633-8338
Richard K. Pelz, Office of General
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SUPPLEMENTARY INFORMATION: On March 19, 1981, Delegation Order No. 0204-33, dated December 21, 1978, and effective January 1, 1979, was amended by substituting the "Assistant Secretary for Conservation and Renewable Energy" for the "Assistant Secretary for Resource Applications."

Issued in Washington, D.C., April 28, 1981.

Frank DeGeorge,

Acting Assistant Secretary, Conservation and Renewable Energy.

Part 903 is amended by changing the reference to "Assistant Secretary for Resource Applications" to "Assistant Secretary for Conservation and Renewable Energy" wherever those words appear in Part 903.

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PENALTY FOR PRIVATE USE, \$300**

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