Administrator's Record of Decision

BPA

1989 Final Rate Proposal

U.S. Department of Energy
Bonneville Power Administration

June 1989

WP-89-A-02

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1989 WHOLESALE POWER AND TRANSMISSION RATE PROPOSAL

RECORD OF DECISION

BONNEVILLE POWER ADMINISTRATION

U.S. DEPARTMENT OF ENERGY

JUNE 1989

RECORD OF DECISION

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COMMONLY USED ACRONYMS

AC - Alternating Current
AFDUC - Allowance for Funds Used During Construction
aMW - Average Megawatt
ASC - Average System Cost
ASM - Aluminum Smelter Model
BASC - Bonneville's Average System Cost
bbl - Barrel
BPA - Bonneville Power Administration
Btu - British Thermal Unit
CEM - Computed Energy Maximum
CF - Firm Capacity (rate)
COSA - Cost of Service Analysis
CRAC - Cost Recovery Adjustment Clause
CSPE - Columbia Storage Power Exchange
CT - Combustion Turbine
CWIP - Construction Work in Progress
DC - Direct Current
DOE - Department of Energy
DSIs - Direct Service Industrial Customers
EA - Environmental Assessment
EB - Energy Broker (rate)
ECC - Energy Content Curve
ET - Energy Transmission (rate)
F&O - Financial and Operating (reports)
FBS - Federal Base System
FCRPS - Federal Columbia River Power System
FCRTS - Federal Columbia River Transmission System
FELCC - Firm Energy Load Carrying Capability
FERC - Federal Energy Regulatory Commission
FOB - Freight On Board
FPT - Formula Power Transmission (rate)
FSEA - Federal Secondary Energy Analysis (computer program)
FY - Fiscal Year (BPA's Fiscal Year is October through September)
GCPs - General Contract Provisions
GRSPs - General Rate Schedule Provisions
GTRSPs - General Transmission Rate Schedule Provisions
GW - Gigawatt (1 trillion watts)
GWh - Gigawatthour
IE - Eastern Intertie (rate)
IN - Northern Intertie (rate)
IOUs - Investor-Owned Utilities
IP - Industrial Firm Power (rate)
IR - Integration of Resources (rate)
IRE - Interruptible Replacement Energy
IS - Southern Intertie (rate)
kV - Kilovolt (1000 volts)
kW - Kilowatt (1000 volts)
kWh - Kilowatthour
LDD - Low Density Discount
LTIAP - Long-Term Intertie Access Policy

Modified SL - Modified Long-Term Surplus Firm Power (rate)
MW - Megawatt (1 million watts)
MWh - Megawatthour
NEPA - National Environmental Policy Act
NF - Nonfirm Energy (rate)
NFRAP - Nonfirm Revenue Analysis Program (computer model)
NR - New Resource Firm Power (rate)
O&M - Operations and Maintenance
OY - Operating Year (BPA's Operating Year is July through June)
PF - Priority Firm Power (rate)
PNUCC - Pacific Northwest Utilities Conference Committee
PNW - Pacific Northwest
PSW - Pacific Southwest
PUD - Public (or Peoples') Utility District
PURPA - Public Utility Regulatory Policies Act
RAM - Rate Analysis Model (computer model)
RAP - Risk Assessment Program (computer program)
RDS - Rate Design Study
REVEST - Revenue Estimate (computer program)
ROD - Record of Decision
SI - Special Industrial (rate)
SP - Surplus Firm Power (rate)
SPM - Supply Pricing Model (computer model)
SPOM - Surplus Firm Power Open Market
SS - Share-the-Savings (nonfirm energy rate)
TGT - Townsend-Garrison Transmission (rate)
UFT - Use of Facilities (rate)
VI - Variable Industrial Power (rate)
WNP - Washington Public Power Supply System (Nuclear) Project
WPPSS - Washington Public Power Supply System
WSPP - Western Systems Power Pool
WSCC - Western Systems Coordinating Council

CHAPTER I

INTRODUCTION

Bonneville Power Administration (BPA) has reviewed its current wholesale power and transmission rate schedules and has determined that current rates will produce sufficient revenue for BPA to meet its statutory requirements and provide satisfactory positive net revenue on a projected basis for fiscal years (FY) 1990 and 1991. Thus, BPA is proposing to extend its 1987 rates through FY 1991 by readopting its 1987 rate schedules, with a modified Cost Recovery Adjustment Clause (CRAC), as its 1989 wholesale power and transmission rate schedules. This proposal has received full and complete support from all parties to the 1989 rate proceeding. The proposed 1989 rate schedules would be effective through FY 1991, except for the Short Term Surplus Firm Power rate (SP-89), which would be effective through September 30, 1994. The wholesale power and transmission rate schedules remain unchanged from the Federal Register notices 54 Fed. Reg. 7825 and 7834 (1988) and the amendment 54 Fed. Reg. 18577 and 19218 (1989) with the exception of the clarification that approval for Formula Power Transmission rate (FPT-89.3) is requested only for the period from October 1, 1990 (its current expiration) to September 30, 1991.

The purpose of the Record of Decision (ROD) is to summarize the events leading to BPA's rate proposal and to briefly describe the key conclusions of BPA's Revenue Requirement Study (E-BPA-01) and Revenue Forecast Study (E-BPA-02). The studies provide a detailed explanation of the rationale supporting the Administrator's decision. The ROD also addresses participants' comments and includes the 1990-91 rate schedules.

A. Procedural History of the Rate Proceeding

Several informal processes leading up to the decision to extend rates provided clarifying information on budget levels, financial goals, and rate design issues used in formulating the initial rate proposal.

1. Informal Procedures

a. Rate Case Simplification

During the spring of 1988, BPA staff reviewed BPA's rate development process. BPA and parties to BPA's 1987 rate case were concerned that the formal process was unduly long, contentious, complicated and included issues decided in prior rate cases. A BPA task group evaluated these concerns and reported to the Administrator in July 1988. The task group concluded that opportunities existed to simplify and shorten the formal hearings process by (1) identifying the key issues to be addressed in the rate case and concentrating BPA's and the parties' efforts on those issues; (2) discussing the issues with the parties prior to the formal process in a series of informal rate case workshops; and (3) reviewing analytical and rate development methodologies with the parties in those workshops.

b. Programs in Perspective

Programs in Perspective is an annual BPA public process in which BPA, its customers and other public interests examine program priorities and major issues facing BPA. During the summer and fall of 1988, BPA held a series of meetings around the Northwest that focused on program levels for FY 1990 and 1991 and on BPA's proposed financial goals and objectives for the same period. Attendees found Programs in Perspective to be an effective process for encouraging the exchange of information useful to BPA in developing its rates. The Administrator considered the comments received during Programs in Perspective as he made decisions on program levels and financial objectives leading to the 1989 rate proposal. The financial goals and objectives are detailed in Section II.B. below.

c. Rate Case Workshops

As recommended by the BPA Rate Case Simplification task group, rate case workshops were held prior to the formal hearings process. The workshops were designed to provide an informal and off-the-record forum for all potential rate case parties to discuss the key issues, introduce new issues, resolve issues where possible, and review BPA rate development methodologies. During the workshops, which were held between October 1988 and February 1989, BPA presented and discussed with the parties the issues covered in previous rate cases and some potential new issues. The series of 13 workshops, each attended by an average of 30 party representatives, received enthusiastic support from the parties and from within BPA as being a useful forum for discussion of rate case issues. The workshops sharpened the focus onto key issues and limited the number of issues that might be contested in the formal rate case. Issues were worked through with the potential parties, and a consensus built up around the proposal for BPA to extend its current rates. As BPA reviewed its financial situation and the outlook for FYs 1990 and 1991 of meeting its financial objectives, BPA was able to propose an extension, along with a modified CRAC. BPA expects that rate case workshops will become a key component in preparing for future general rate adjustments.

2. Formal Procedure

As the informal processes described above neared completion, on December 23, 1988, BPA published notices of intent to revise its wholesale power and transmission rates, a formality required by contract. 53 Fed. Reg. 51890 and 51891 (1988). BPA subsequently initiated formal procedures to extend its 1987 rates by proposing to readopt its 1987 rates, with a modified CRAC, as its 1989 rates. BPA published its proposal on February 23, 1989, 54 Fed. Reg. 7825 and 7834 (1988), together with notice of the date, time, and location of the prehearing conference, all in accordance with 16 U.S.C. § 839e(i)(1). BPA published amendments to the initial proposal for transmission rates on May 1, 1989, 54 Fed. Reg. 18577 (1989), and for wholesale rates on May 4, 1989, 54 Fed. Reg. 19218 (1989), which announced changes in the procedural schedule. The proposed effective date for the new rates is October 1, 1989, subject to interim approval of the Federal Energy Regulatory Commission (FERC or Commission). 16 U.S.C. § 839e(a)(2).

BPA's Federal Register notices noted that none of BPA's major customer groups had indicated opposition to the proposal to readopt rates, and expressed the Administrator's consequent expectation that parties would not avail themselves of the opportunity for hearing afforded by the Procedures Governing Bonneville Power Administration Rate Hearings, 51 Fed. Reg. 7611 (1986). Accordingly, the Federal Register notices provide that,

> [U]pon due and appropriate motion, the Hearing Officer will truncate the proceedings so that participants may be quickly heard and parties extended the opportunity to comment on the Administrator's Draft Record of Decision. In the event a truncated procedure is adopted, the Administrator directs the Hearing Officer to incorporate by reference the Official Record compiled in BPA's 1987 Wholesale Power and Transmission Rate Proceeding into the Official Record of this proceeding.

54 Fed. Reg. 7825, 7827 (February 23, 1989); see also 54 Fed. Reg. 7834, 7836 (February 23, 1989). The Federal Register Notices also state as follows:

> Parties appearing at the prehearing conference shall be required to state whether they will oppose BPA's rate proposal, provided that BPA will have first offered satisfactory assurances that no substantive or procedural precedent shall arise by virtue of the substance, manner, or form of BPA's or any other party's action in connection with the rate proposal, and that the extended rates suffer the same entire or partial legality as the 1987 wholesale power rates . . . .

54 Fed. Reg. 7825, 7827 (February 23, 1989); see also 54 Fed. Reg. 7834, 7836 (February 23, 1989). These requirements were reaffirmed in BPA's subsequent Federal Register notices.

In accordance with section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839(e)(i), on May 12, 1989, Hearing Officer Dean F. Ratzman conducted a prehearing conference in the BPA Hearing Room in Portland, Oregon. Hearing Officer Ratzman ruled on intervention petitions and established the procedural schedule. Twenty five intervention petitions were filed by publicly owned and investor-owned utility customers, direct-service industrial customers, State agencies, Federal agencies, and public interest groups.

By Motion dated May 1, 1989, BPA requested the Hearing Officer to, among other things, incorporate the record of BPA's 1987 rate proceeding into the record of the 1989 rate case for specified purposes, admit BPA's testimony and studies into evidence, provide procedures for participants' comments and the issuance of a Record of Decision, and establish such assurances as would be necessary to satisfy parties that no precedent is being set and any errors preserved in the 1987 rates inhere in the proposed rates. BPA accompanied its Motion with a proposed order.

At the prehearing conference, Hearing Officer Ratzman took up BPA's Motion for Prehearing Order and Proposed Order, allowing argument from the parties on the subject and extending parties the opportunity to fully state their objections to BPA's proposed rate extension and its Motion for Prehearing Order and Proposed Order. Based on the assurances and other delineation of rights and obligations set forth in the ordering language of the Proposed

Order, no party opposed either BPA's proposed rate extension or its Motion for Prehearing Order.

Hearing Officer Ratzman, therefore, granted BPA's Motion for Prehearing Order and issued an Order, which included a revised schedule and errata, in substantially the same form as BPA's Proposed Order. The Hearing Officer's Prehearing Order stated in part the following:

> (1) The Official Record of the Bonneville Power Administration's 1987 Wholesale Power and Transmission Rate Proceeding (hereafter the 1987 Official Record) is incorporated by reference in its entirety into the Official Record of this case for the purposes of (a) providing such information as may be necessary to establish and thereafter justify the proposed 1989 Wholesale Power and Transmission rates (hereafter 1989 rates), and (b) preserving to any party to this case any position, and all record bases in support thereof, that party took in the 1987 Official Record, which position shall be deemed taken in this proceeding. In regard to the latter, BPA represents, all parties agree, and it is therefore further ordered that (a) any errors in the 1987 rates inhere in the proposed rates such that a remand of any or all of the 1987 rates or other relief with respect to such rates by the Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the Ninth Circuit or the United States Supreme Court shall also serve as sufficient cause for like relief with respect to the corresponding 1989 rate or rates, which like relief BPA will not oppose and will take the necessary actions to effectuate, and (b) BPA shall make the same representation before FERC and, in the event of appeal, the Ninth Circuit Court of Appeals and the U.S. Supreme Court.
>
> ***
>
> (3) No action taken or not taken by BPA or any party to this case in the establishment of the 1989 rates here or in any subsequent administrative or judicial forum reviewing such rates shall serve to create any procedural or substantive precedent, and neither BPA nor any party shall argue otherwise.
>
> (4) Extension of the 1987 rates via adoption of the 1989 rates herein means that no change will occur in the calculation of BPA's average system cost as defined in the General Rate Schedule Provisions through the rate period October 1, 1989 to September 30, 1991.

1989 Bonneville Power Administration Wholesale Power and Transmission Rate Proceeding, Hearing Officer's Order of May 12, 1989, at 2-3, WP-89-O-01. The Administrator hereby adopts and otherwise confirms the assurances and other matters just quoted, and extends the assurances to include participants as well as parties.

BPA's initial proposal consisted of prefiled written testimony and studies sponsored by three witnesses. No further process was requested by the parties at the Prehearing Conference except to review a draft of the Record of Decision. For interested persons who did not wish to become or were not allowed to become parties to the formal proceeding, BPA received and considered 12 written comments through May 31, 1989. The written comments have become part of the record on which the Administrator bases his decisions.

This document presents the BPA Administrator's decision based on his review of the studies and written comments. The final Record of Decision takes into account all comments. Comments will be received through June 23, 1989.

B. Legal Guidelines Governing Establishment Of Rates

1. Statutory Guidelines

Section 6 of the Bonneville Project Act, 16 U.S.C. § 832e, requires that the Administrator prepare schedules of rates and charges for electric energy sold to purchasers. Rate schedules become effective upon confirmation and approval by the Federal Power Commission (succeeded by FERC). Section 6 directs the Administrator to establish rates with a view to encouraging the widest possible diversified use of electric energy. Section 7 of the Bonneville Project Act, 16 U.S.C. § 832f, provides that rate schedules are to be established having regard to the recovery of the cost of producing and transmitting electric energy, including amortization of the capital investment over a reasonable period of years.

The Federal Columbia River Transmission System Act (Transmission Act), 16 U.S.C. § 838, contains requirements similar to those of the Bonneville Project Act. Section 9 of the Act, 16 U.S.C. § 838g, provides that rates shall be established: (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles; (2) with regard to the recovery of the cost of producing and transmitting electric power, including amortization of the capital investment allocated to power over a reasonable period of years; and (3) at levels that produce such additional revenues as may be required to pay when due the principal, premiums, discounts, expenses, and interest in connection with bonds issued under the Transmission Act. Section 10 of the Transmission Act, 16 U.S.C. § 838h, allows for uniform rates, and specifies that the costs of the Federal transmission system be equitably allocated between Federal and non-Federal power utilizing the system.

The Flood Control Act of 1944 contains ratemaking requirements similar to the Bonneville Project Act and the Transmission Act. Section 5 of the Flood Control Act directs that rate schedules should encourage the most widespread use of power at the lowest possible rates to consumers consistent with sound business principles. 16 U.S.C. § 825s. Section 5 also provides that rate schedules should be drawn having regard to the recovery of the cost of producing and transmitting such electric energy, including the amortization of the Federal investment over a reasonable number of years.

In addition to the Bonneville Project Act, the Transmission Act, and the Flood Control Act of 1944, the Northwest Power Act provides numerous rate directives. Section 7 directs the Administrator to establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Rates are to be set to recover, over a reasonable period of years, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (FCRPS) (including irrigation costs required to be repaid by power revenues). 16 U.S.C. § 839e(a)(1). Section 7 also contains rate directives describing how rates for individual customer groups may be derived.

Section 7 also provides procedural guidelines to be used when developing rates, including publication of notice in the Federal Register of the proposed rates, a hearing before a hearing officer, an opportunity to submit oral and written comment, and an opportunity to refute or rebut other material submitted for the record. 16 U.S.C. 839e(i). BPA has expanded on these statutory directives by promulgating rules of agency procedure to aid in the conduct of these hearings. 51 Fed. Reg. 7611 (1986).

2. The Broad Ratemaking Discretion Vested In The Administrator

The Administrator has broad discretion to interpret and implement statutory standards applicable to ratemaking. These standards focus on cost recovery and do not restrict the Administrator to any particular rate design methodology or theory. *See* *Pacific Power & Light v. Duncan*, 499 F. Supp. 672 (D.C. Or. 1980); *accord* *City of Santa Clara v. Andrus*, 572 F.2d 660, 668 (9th Cir. 1978) ("widest possible use" standard is so broad as to permit "the exercise of the widest administrative discretion"); *ElectriCities of North Carolina v. Southeastern Power Administration*, 774 F. 2d 1262, 1266 (4th Cir. 1985).

The United States Court of Appeals for the Ninth Circuit has also recognized the Administrator's ratemaking discretion. *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1120-29 (9th Cir. 1984) (Upheld BPA on the merits of every rate issue and stated "[b]ecause BPA helped draft and must administer the Act, we give substantial deference to BPA's statutory interpretation."); *Pacificorp v. FERC*, 795 F.2d 816, 821 (9th Cir. 1986) ("BPA's interpretation is entitled to great deference and must be upheld unless it is unreasonable."); *Atlantic Richfield Co. v. Bonneville Power Administration*, 818 F.2d 701, 705 (9th Cir. 1987) (BPA's rate determination upheld as a "reasonable decision in light of economic realities"); *cf.* *Aluminum Company of America v. Central Lincoln Peoples' Utility District*, 467 U.S. 380, 389 (1984) ("The Administrator's interpretation of the Regional Act is to be given great weight."); *Department of Water and Power of the City of Los Angeles v. BPA*, 759 F.2d 684, 690 (9th Cir. 1985) ("Insofar as agency action is the result of its interpretation of its organic statutes, the agency's interpretation is to be given great weight.").

C. Confirmation And Approval of Rates

BPA's rates become effective upon confirmation and approval by FERC. 16 U.S.C. §§ 839e(a)(2) and (k). FERC's review is appellate in nature, based on the record developed by the Administrator. *United States Dep't of Energy, Bonneville Power Admin.*, 13 F.E.R.C. ¶ 61,157, 61,339 (1980). The Commission may not modify rates proposed by the Administrator, but may only confirm, reject or remand them. *United States Dep't of Energy, Bonneville Power Admin.*, 23 F.E.R.C. ¶ 61,378, 61,801 (1983).

With respect to all rates other than those for sales of nonfirm power outside the Pacific Northwest, the Commission determines whether (1) rates are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting BPA's other costs; (2) rates are based on BPA's total system costs; and (3) transmission rates equitably allocate the cost of the Federal transmission system between Federal and non-Federal power using the system. United States Dep't of Energy, Bonneville Power Admin., 39 F.E.R.C. ¶ 61,078, 61,206 (1987). The limited FERC review of all but nonregional nonfirm rates permits the Administrator substantial discretion in the design of rates and the allocation of costs, neither of which are subject to FERC jurisdiction. Central Lincoln Peoples' Utility District v. Johnson, 735 F.2d 1101, 1115 (9th Cir. 1984).

Although both regional and nonregional rates are established by the Administrator under common statutory standards, FERC review of nonregional rates for sales of nonfirm energy is undertaken pursuant to section 7(k) of the Northwest Power Act. 16 U.S.C § 839e(k). The Commission reviews nonregional nonfirm energy rates to ascertain that BPA has designed rates (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 BPA power; (3) to provide the lowest possible rates to consumers consistent with sound business principles; and (4) in a manner that protects the interest of the United States in amortizing its investments in the projects within a reasonable number of years. United States Dep't of Energy, Bonneville Power Admin., 36 F.E.R.C. ¶ 61,335, 61,798 (1986).

Pursuant to section 7(i)(6) of the Northwest Power Act, 16 U.S.C. § 839e(i)(6), FERC has promulgated rules establishing procedures for the approval of BPA rates. 18 C.F.R. 300 (1988).

CHAPTER II

MAJOR CONSIDERATIONS

A. Current Revenue Test

BPA's revenue requirements for the rate approval period FY 1990-FY 1991 are set forth in the Revenue Requirement Study (E-BPA-01). BPA's rates must be prepared consistent with its statutory obligation to set rates to recover, in accordance with sound business principles, all costs of acquiring, conserving, and transmitting electric power, including repayment of the Federal investment in the FCRPS over a reasonable number of years, and all other BPA costs. As required by Department of Energy Order R.A. 6120.2, BPA conducted a test of the adequacy of revenues under current rates to meet the cost recovery criteria. E-BPA-01, 47-56. The current revenue test determines whether the revenues expected from current rates can meet annual expenses and satisfy BPA's repayment obligations.

The amortization payments on Federal investment as determined by the power repayment studies and used in determining revenue requirements for generation and transmission are shown below (E-BPA-01, 6, 117, 163):

AMORTIZATION
CURRENT REPAYMENT STUDIES
($000)

Fiscal Year	Generation (All Other)	Transmission (FCRTS)	Total
1990	51,631	101,503	153,134
1991	60,665	115,652	176,317
Total	112,296	217,155	329,451

The results of the current power repayment studies for generation and transmission demonstrate the adequacy of current rates to repay the Federal investment within the allowable repayment period. In each year of the repayment period, the amount of allowable unamortized investment is greater than the unamortized investment, assuring that repayment of the Federal investment is on or ahead of schedule. E-BPA-01, 108, 116.

As shown below, for the rate approval period FY 1990-1991, revenues under current rates exceed revenue requirements in both the generation and transmission functions of the FCRPS. E-BPA-01, 6, 29-32, 50-53. Thus, projected revenues under current rates are fully sufficient to recover all projected costs and expenses of the FCRPS, including amortization of the Federal investment over a reasonable number of years as required by law.

CURRENT REVENUE TEST
PROJECTED COST RECOVERY USING CURRENT RATES
FY 1990-1991
($000)

Fiscal Year		Generation (All Other)	Transmission (FCRTS)	Total
1990	Projected Revenues From Current Rates	2,388,462	450,376	2,838,838
	Revenue Requirement	2,317,860	431,823	2,749,683
	Revenues Over Minimum Requirements	70,602	18,553	89,155
1991	Projected Revenues From Current Rates	2,465,561	451,749	2,917,310
	Revenue Requirement	2,384,618	444,942	2,829,560
	Revenues Over Minimum Requirements	80,943	6,807	87,750

BPA also assessed the adequacy of revenues under current rates to determine its ability to meet additional financial objectives described in Section II.B. BPA performed a Risk Analysis, discussed in Section II.C., to determine the sufficiency of revenues from current rates to satisfy those financial objectives. E-BPA-02, 21-26. The Risk Analysis determined a base case probability of meeting the financial objectives by determining the variability of projected revenues compared to BPA's projected base case expenses and financial obligations over the FY 1989-FY 1991 period. In addition, the Risk Analysis analyzed the sensitivity of the base case probabilities to changes in projected costs to obtain a sensitivity range of probabilities.

As discussed in Section II.C., the Risk Analysis demonstrates that projected revenues at current rates allow BPA to meet its financial objectives within a reasonable range of certainty. Projected revenues at current rates are sufficient to meet minimum revenue requirements as well as to provide the desired level of assurance that BPA will meet its financial objectives, including timely repayment to the U.S. Treasury. E-BPA-01, 57-61.

B. Financial Goals and Objectives

Before beginning the 1989 rate proceeding, BPA conducted an extensive public involvement process to consider program priorities to be used in determining revenue requirements for the FY 1990-91 rate approval period. This public process, called Programs in Perspective, began in January of 1988 and provided a context in which BPA made its decisions in planning for the FY 1990-1991 rate approval period. Initial discussions focused on broad issues facing the agency. Subsequent discussions focused on specific program levels to be included in revenue requirements.

After discussions throughout the Pacific Northwest with BPA's customers and other interested parties, BPA adopted financial goals as it planned for the FY 1990-1991 rate approval period. The goals were established to enable BPA to maintain stable rates into the long term and thereby secure BPA's status as a sound business partner. To this end, BPA resolved to restore and maintain its financial strength, and reaffirmed that its ability to meet its annual payments to the U.S. Treasury is among the highest of its priorities. E-BPA-01, 22.

BPA also determined that it must increase its financial flexibility to better position itself to cope with unexpected fluctuations in revenues and to keep its costs under control. BPA weighed numerous considerations and then set financial objectives specifying that revenue levels in the FY 1989-1991 cost evaluation period should be sufficient to:

- provide at least a 95 percent probability of meeting annual amortization payments to the U.S. Treasury each year;
- provide at least an 80 percent probability that current revenues cover current expenses; and
- provide a reasonable likelihood of reducing BPA's negative accumulated net revenue position by $300 million by the end of FY 1991, toward eliminating the negative accumulated net revenues by the mid-1990s (i.e., with a 50 percent or greater probability). Achieving this objective would move BPA toward full recovery of FCRPS expenses over time, and help reduce BPA's fixed costs and debt burden.

E-BPA-01, 22. The adequacy of revenues under current rates to allow BPA to meet these financial objectives was evaluated by means of the Risk Analysis discussed in the next section.

C. Revenue Forecast and Risk Analysis

The Revenue Forecast Study (E-BPA-02) presents BPA's revenue forecast used in the 1989 BPA rate proposal. It details BPA's expected revenue based on current rates for FY 1989 and the extension of current rates through FY 1991. E-BPA-02, 38-43. The study describes the process and the major assumptions used to forecast revenues and the significant changes since the 1987 rate proposal. E-BPA-02, 1-21.

The revenue forecast and its assumptions were issues that received significant public review during the Programs in Perspective process and during the rate case workshops. As a result, this revenue forecast is more realistic in many respects than forecasts used in past rate proposals. The assumptions used in this forecast include the following: aluminum prices declining from current prices near $1.00 per pound to 75 cents per pound in FY 1990 and to 72 cents per pound in FY 1991 (E-BPA-02, 7); little load growth from BPA's generating and nongenerating public utility customers (E-BPA-02, 3-4); a small increase in the price of natural gas (E-BPA-02, 19); only contractually committed surplus power sales (E-BPA-02, 5); and a 15 percent reduction from incremental fuel cost in the price BPA would receive for spot market sales (E-BPA-02, 12).

This revenue forecast is based on the average of the revenues from fifty historical streamflows. E-BPA-02, 2. In the 1985 and 1987 rate proposals, BPA used the 1939 streamflow assumption (which reflected below average conditions) to determine rate levels as a part of BPA's risk protection measures. However, the assumption of 1939 streamflow was confusing and contentious, and provided an uncertain amount of risk protection. Rather than use the 1939 streamflow assumption, BPA decided to shift the risk protection to more direct measures, including projected net revenue levels. This change was supported by the participants in BPA's rate case workshops. Therefore, BPA used the average of the fifty historical streamflows as the most reasonable assumption in the revenue forecast, without forgoing the desired total level of risk protection.

BPA developed the Risk Analysis Program and conducted the risk analysis to determine if BPA's rates meet BPA's established financial objectives as described in Section II.B, and to test different formulations of the CRAC. The risk analysis measures the impact of the variability of five risk factors on BPA revenue. These five factors--economic conditions (including regional employment and aluminum prices), thermal resource performance, fuel prices/SP contract sales, streamflows, and the level of the WNP-1 Exchange contract charge--have a significant influence on BPA revenue. BPA defined three levels for each of these factors--high, medium, and low. High and low levels were chosen for each factor based on a reasonable chance of occurrence. BPA decided that more extreme values for one factor would not be appropriate because the cumulative risk of several moderately adverse effects occurring simultaneously would better define the total risk to BPA and the Treasury. E-BPA-02, 22-24.

BPA assumed that risks due to regional employment and aluminum prices are linked, since both are dependent upon economic conditions. In previous rate proposals these risks were assumed to be independent. Some parties have commented that the sales assumption for the low economic factor appeared to be too low for the probability assigned to it. BPA believes that, due to the potential adverse risks it faces because of economic conditions, the sales forecast for the low economic factor is prudent for use in the risk analysis.

BPA estimated the revenue from 243 possible scenarios for FYs 1989-91, which encompass all the possible combinations of the identified risk factors. BPA assumed that each of the risk factors was independent and that the factors were independent from year to year. Because the values of the risk factors were assumed to be independent from year to year, the revenue was also assumed to be independent except to the extent it was influenced by the CRAC. E-BPA-02, 44-45. The risk analysis demonstrates that BPA can extend its current rates with a modified CRAC for two years and have a high probability of meeting its financial objectives. E-BPA-02, 25-27.

The risk due to changes in expenses was not treated as a risk factor in the risk analysis, but rather the level of expenses is an input variable. In order to assess the impact of expenses on meeting BPA's financial objectives, expense levels input into the risk analysis were assumed to vary from \$54 million higher than base case expenses to \$85 million below base case expenses, E-BPA-02, 26-27, 46, yielding sensitivity ranges for the probabilities of meeting the financial objectives. As a result of the recent developments regarding the settlement of WPPSS lawsuits, which improve the likelihood of debt-financing Supply System capital investment and refinancing existing debt, BPA estimates that the low expense scenario has a greater likelihood of occurring than the high expense scenario. E-BPA-01, 58-61.

The financial objectives and the results of the risk analysis with the sensitivity ranges due to expense variation are shown on the table below.

ABILITY TO MEET FINANCIAL OBJECTIVES
WITH PROJECTED REVENUES FROM CURRENT RATES

(Probabilities for the Cost Evaluation Period, FY 1989-FY 1991)

		Current Revenue Test Risk Analysis Results	
Financial Objective	Target Probability	Base Case	Sensitivity Range
Meeting Annual Amortization Payments to the U.S. Treasury	95%	98%	95-99%
Current Revenues will meet Current Expenses	80%	89%	84-94%
Reducing BPA's Negative Accumulated Net Revenue by $300 Million	50%	43%	34-57%

While the probability of reducing the negative accumulated net revenue by $300 million by the end of FY 1991 is less than the goal of 50 percent in the base case, the goal is within the sensitivity range. For the reasons set forth in BPA's Revenue Requirement Study, E-BPA-01, the Administrator has determined that the probability that the financial objective will be met is within a reasonable range of certainty.

The standards for meeting BPA's financial objectives are comparable to those stated in the 1987 rate proposal. In the 1987 rate proposal, for the rate period BPA estimated the probability of making its scheduled Treasury payments at 90 percent and the probability of covering expenses at 56 percent. WP-87-FS-BPA-06, B15. However, the risk analysis has been modified since the 1987 rate proposal. The most significant difference is that only negative revenue risks were considered in the 1987 proposal. Many parties encouraged BPA to consider a range of positive and negative outcomes, which BPA has done for the 1989 rate proposal.

In the 1987 rate proposal, the total risk protection available over the FY 1988-89 period to make the Treasury payment (before consideration of the CRAC) was $414 million. E-BPA-02, 48. In the 1989 rate proposal, the total risk protection available over the FY 1990-91 period to make the Treasury payment (before consideration of the CRAC) is $415 million. Id. In the 1987 rate proposal, a large portion of the protection was provided by the 1939 water assumption. In this proposal, the majority of the protection is provided through revenue in excess of expenses.

The results of the risk analysis allow the Administrator to conclude that BPA can meet its established financial objectives through the extension of current rates through FY 1991.

D. Cost Recovery Adjustment Clause

With the extension of the 1987 rates through FYs 1990 and 1991, BPA is proposing a modified 1989 Cost Recovery Adjustment Clause similar to the 1987 CRAC. A CRAC was first incorporated in the 1987 wholesale power rate schedules to provide BPA added assurance of cost recovery from current customers without substantially overrecovering costs during the rate period. WP-87-A-02, 53.

The 1989 CRAC will continue to help assure that BPA can make Treasury payments and meet expenses during the rate period while maintaining rates at the lowest possible levels. In addition, it will prevent deterioration of BPA's financial position as measured by its accumulated net revenue. E-BPA-02, 27-28.

The basic structure of the 1989 CRAC is the same as the 1987 CRAC with three key differences. The first difference is the definition of the trigger point. The 1987 CRAC was designed to trigger when the difference between actual and planned funds from operations was greater than $45 million. The 1989 CRAC will instead measure the difference between actual revenues and actual expenses (net revenues). If net revenues fall below zero, the CRAC will trigger. The amount of the revenue to be recovered through the CRAC will equal the amount that the net revenue falls below zero, up to a maximum defined by a 10 percent increase in the five affected rates. E-BPA-02, 28-29. Should CRAC trigger to the maximum, the five affected rate schedules (PF-89, IP-89, VI-87, CF-89, and NR-89) will recover $127.0 million in FY 1990 and $138.4 million in FY 1991. E-BPA-02, 34, G19 and G20.

The second difference is the period of coverage. The 1987 CRAC was limited to one evaluation and one adjustment period. The 1989 CRAC has two evaluation periods (12 months each) and two adjustment periods (9 months each). Net revenues will be measured for FY 1989 and, if they are less than zero, the CRAC may be implemented in the last 9 months of FY 1990. Similarly, net revenues will be measured in FY 1990 and, if less than zero, the CRAC will be implemented in the last 9 months of FY 1991. The latter evaluation will be adjusted for any CRAC adjustment made based on FY 1989 financial results. E-BPA-02, 29-30.

The third difference is that the 1989 CRAC does not provide for a downward adjustment in rates. In the 1989 rate period, if net revenue is greater than zero, BPA currently plans to use the available funds to improve its financial position rather than adjusting rates downward. Any adjustment to rates (PF-89, IP-89, VI-87, CF-89, and NR-89) will be upward only and will not exceed 10 percent. E-BPA-02, 31.

The formulas to determine the percent of increase to rates are the same as those used for the 1987 CRAC except that they have been simplified. A small irrigation discount term has been added to the 1989 formulas. E-BPA-02, G5-G18. Regardless of the result of the calculation of the level of a CRAC adjustment, the Administrator has the discretion to not implement an adjustment for either period. E-BPA-02, 30-31.

CHAPTER III
COMMENTS OF PARTICIPANTS

Introduction

This chapter summarizes the comments of "participants" in BPA's 1989 rate proceeding. Participants are persons and organizations who comment on BPA's rate proposal but do not take part in the formal proceeding. Participants' comments are made part of the Official Record of the proceeding, the same as official comments of the parties.

Comments addressed in this chapter are those received by BPA after the initial rate proposal was published February 22, 1989. Twelve participants submitted comments to the Official Record:

Springfield Utility Board (SUB)
Glacier Electric Cooperative, Inc.
The City of McCleary
Upper Columbia United Tribes Fisheries Research Center
Public Utility District of Clark County
City of Burley Electrical Department
Northwest Irrigation Utilities (NIU)
Public Utility District 3 of Mason County
Western Montana Electric Generating & Transmission Cooperative
Rural Electric Company
Southern California Edison Company (SCE)
Pacific Gas and Electric Company

Summary of Comments

Comment: All of the participants supported BPA's decision to extend current (1987) rates through FYs 1990 and 1991. The participants expressed their appreciation for BPA's efforts to stabilize rates.

Comment: The Upper Columbia United Tribes Fisheries Research Center stated that BPA should consider the costs of implementing the Northwest Power Planning Council's Fish and Wildlife Program to be fixed, rather than discretionary, costs. WP-89-W-04.

Response: BPA bases its decisions on program spending levels (for programs such as conservation and fish and wildlife) on information developed by its staff and obtained in public processes, including Programs in Perspective. BPA set its program budget levels (on which the FY 1990-1991 rates would be based) prior to the rate proceeding. BPA's Administrator announced those program levels in a letter dated December 1, 1988. Program levels are not at issue in the rate proceeding. See the Revenue Requirement Study, WP-89-E-BPA-01, page 22 and Appendix A.

Comment: Northwest Irrigation Utilities stated its concern about "BPA's continued movement away from seasonally defined wholesale power rates." WP-89-W-07.

Response: Since BPA is extending its 1987 rates through FYs 1990 and 1991, rate design is not at issue in this proceeding.

Comment: Southern California Edison Company stated that the Hearing Officer should issue the Proposed Prehearing Order as submitted by BPA with its Motion for Prehearing Order (May 1, 1989), except that the word "party" should be changed to "party or participant."

Response: BPA filed its Motion for Prehearing Order with the Hearing Officer May 1; BPA made the Motion available with its studies, documentation, and testimony the same day. The Hearing Officer heard arguments concerning BPA's Motion at the prehearing conference May 12. After considering the arguments, the Hearing Officer issued an Order with substantially the same form as BPA's Proposed Prehearing Order. See Chapter II.2. Since the Order has already been issued, SCE's comment is untimely. Addressing the substance of SCE's comment, though, this Record of Decision extends the assurances to participants as well as parties. See section I.A.2.

CHAPTER IV

CONCLUSION

As required by law, BPA's rates have been set to recover the costs associated with the production, acquisition, conservation, and transmission of electric power. Costs include the amortization of the Federal investment in the Federal Columbia River Power System over a reasonable period of years, and other costs and expenses incurred in carrying out the requirements of the Northwest Power Act and other provisions of law. In addition, these rates have been designed to be as low as possible, consistent with sound business principles, to encourage the widest possible use of electricity, and to satisfy BPA's other ratemaking obligations.

In performing his duties under section 7(i) of the Northwest Power Act, the Hearing Officer has assured that all interested parties and participants were given the opportunity for a full and fair evidentiary hearing. Due to the high level of support for BPA's proposal to extend rates, parties accepted the Prehearing Order outlining a truncated process; a full process was not considered necessary by the parties.

In accordance with FERC regulation section 300.10(g), 18 C.F.R. § 300.10(g), I hereby certify that the proposed Wholesale Power and Transmission Rate Schedules are consistent with applicable laws and that they will result in the lowest possible rates consistent with sound business principles.

After considering all comments in this proceeding, and based upon the record compiled in this proceeding, I hereby adopt the attached Wholesale Power and Transmission Rate Schedules as final Bonneville Power Administration rates.

Issued at Portland, Oregon, this 28th day of June 1989.

Jack Robertson

Jack Robertson
Administrator

APPENDICES

APPENDIX A

List of Parties and Abbreviations

Association of Public Agency Customers	APAC
Atlantic Richfield Company	ARCO
Bonneville Power Administration	BPA
California Energy Commission	CEC
California Public Utilities Commission	CPUC
Chelan County PUD No. 1	Chelan
Cowlitz County PUD No. 1	Cowlitz Co.
Direct Service Industries	DSIs
Eugene Water & Electric Board	EWEB
Fall River Rural Electric Cooperative, Inc.	Fall River
Grant County PUD No. 2	GRT
Non-Generating Public Utilities	Non-generating
Oregon Public Utility Commissioner	OPUC
Pacific Northwest Generating Company	PNGC
PacifiCorp	PacifiCorp
Portland General Electric Company	PGE
Public Generating Pool	PGP
Public Power Council	PPC
Puget Sound Power & Light Company	PSP&L
Seattle City Light	SCL
Tacoma City Light	TCL
Washington Water Power Company	WWPC
Western Public Agencies Group	WPAG

APPENDIX B

WHOLESALE POWER RATE SCHEDULES

and

GENERAL RATE SCHEDULE PROVISIONS

WHOLESALE POWER RATES AND GENERAL RATE SCHEDULE PROVISIONS

TABLE OF CONTENTS

SCHEDULE PF-89

PRIORITY FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of firm power or capacity to be used within the Pacific Northwest. Priority Firm Power may be purchased by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers, for direct consumption, construction, test and start-up, and station service.

Utilities participating in the exchange under section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to their Residential Purchase and Sale Agreements.

In addition, Bonneville Power Administration (BPA) may make power available to those parties participating in exchange agreements which use this rate schedule as the basis for determining the amount or value of power to be exchanged.

This schedule supersedes Schedule PF-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

This rate schedule includes the Preference rate and the Exchange rate. The Preference rate is available for the general requirements of public body, cooperative and Federal agency customers and includes credit attributed to the provision of section 7(b)(2) of the Northwest Power Act. The Exchange rate is available for all purchases of residential and small farm exchange power pursuant to the Residential Purchase and Sale Agreements.

A. Preference Rate

1. Demand Charge

   a. $3.46 per kilowatt of billing demand occurring during all Peak Period hours.

   b. No demand charge during Offpeak Period hours.

2. Energy Charge

   a. 18.4 mills per kilowatthour of billing energy for the billing months September through March;

   b. 14.4 mills per kilowatthour of billing energy for the billing months April through August.

B. Exchange Rate

1. Demand Charge

a. $3.56 per kilowatt of billing demand occurring during all Peak Period hours.

b. No demand charge during Offpeak Period hours.

2. Energy Charge

a. 19.1 mills per kilowatthour of billing energy for the billing months September through March;

b. 15.1 mills per kilowatthour of billing energy for the billing months April through August.

SECTION III. BILLING FACTORS

In this section, billing factors are listed for each of the following types of purchasers: computed requirements purchasers (section III.A), purchasers of residential exchange power pursuant to the Residential Purchase and Sale Agreements (section III.B), and metered requirements purchasers and those Priority Firm Power purchasers not covered by sections III.A and III.B (section III.C).

A. Computed Requirements Purchasers

Purchasers designated by BPA as computed requirements purchasers pursuant to power sales contracts shall be billed in accordance with the provisions of this subsection.

1. Billing Demand

The billing demand for actual, planned, and contracted computed requirements purchasers shall be the higher of the billing factors "a" and "b," below:

a. the lower of:

(1) the larger of the Computed Peak Requirement or the Computed Average Energy Requirement; or

(2) the Measured Demand, before adjustment for power factor.

b. the lower of:

(1) the Computed Peak Requirement, or

(2) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).

2. Billing Energy

The billing energy for actual, planned, and contracted computed requirements purchasers shall be:

a. for the months September through March, the sum of:

(1) 78 percent of the Measured Energy (excluding unauthorized increase), and

(2) 22 percent of the Computed Energy Maximum;

b. for the months April through August, the sum of:

(1) 57 percent of the Measured Energy (excluding unauthorized increase), and

(2) 43 percent of the Computed Energy Maximum.

B. Purchasers of Residential Exchange Power

Purchasers buying Priority Firm Power under the terms of a Residential Purchase and Sale Agreement shall be billed as follows:

1. Billing Demand

The billing demand shall be the demand calculated by applying the load factor, determined as specified in the Residential Purchase and Sale Agreement, to the billing energy for each billing period.

2. Billing Energy

The billing energy shall be the energy associated with the utility's residential load for each billing period. Residential load shall be computed in accordance with the provisions of the purchaser's Residential Purchase and Sale Agreement.

C. Metered Requirements Purchasers, Other Purchasers Not Covered by Sections III.A and III.B, Above

Purchasers designated as metered requirements customers and purchasers taking or exchanging power under this rate schedule who are not otherwise covered by sections III.A and III.B shall be billed as follows:

1. Billing Demand

The billing demand shall be the Measured Demand as adjusted for power factor, unless otherwise specified in the power sales contract.

2. Billing Energy

The billing energy shall be the Measured Energy, unless otherwise specified in the power sales contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Low Density Discount (LDD)

BPA shall apply a discount to the charges for all Priority Firm Power sold to purchasers who are eligible for an LDD. Eligibility for the LDD and the amount of the discount (3, 5, or 7 percent) shall be determined pursuant to section III.C.3 of the GRSPs.

C. Irrigation Discount

BPA shall apply an irrigation discount, equal to 4.6 mills per kilowatthour, to the charges for qualifying energy purchased under this rate schedule. The irrigation discount shall be applied after calculation of the Low Density Discount. The discount shall apply only to energy purchased during the billing months of April through October. Eligibility for the irrigation discount and reporting requirements shall be determined pursuant to section III.C.4 of the GRSPs.

D. Conservation Surcharge

The Northwest Power Planning Council has recommended that a conservation surcharge be imposed on those customers subject to such surcharge as determined by the Administrator in accordance with BPA's Policy to Implement the Council-Recommended Conservation Surcharge. The Conservation Surcharge shall be applied pursuant to section III.C.7 of the GRSPs and subsequent to any other rate adjustments.

E. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all purchases and exchanges under this rate schedule. The percentage increase calculated in section III.C.5.c of the GRSPs shall be applied uniformly to the demand and energy charges contained in sections II.A and II.B and the irrigation discount contained in section IV.C of this rate schedule. An additional increase of .046 mills per kilowatthour shall be made to the irrigation discount for each percentage increase in the PF rates due to the Cost Recovery Adjustment Clause.

F. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Priority Firm Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

G. Unauthorized Increase

BPA shall apply the charge for Unauthorized Increase to any purchaser of Priority Firm Power taking demand and energy in excess of its contractual entitlement.

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Calculation of the Amount of Unauthorized Increase

Each 60-minute clock-hour integrated or scheduled demand shall be considered separately in determining the amount that may be considered an unauthorized increase. BPA first shall determine the amount of unauthorized increase related to demand and shall treat any remaining unauthorized increase as energy-related.

a. Unauthorized Increase in Demand

That portion of any Measured Demand during Peak Period hours, before adjustment for power factor, which exceeds the demand that the purchaser is contractually entitled to take during the billing month and which cannot be assigned:

(1) to a class of power that BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or

(2) to a type of power that the purchaser acquires from sources other than BPA and that BPA delivers during such hour, shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) if such exhibit does not apply or is not a part of the purchaser's power sales contract, at the rate for Unauthorized Increase, based on the amount of energy associated with the excess demand.

b. Unauthorized Increase in Energy

The amount of Measured Energy during a billing month which exceeds the amount of energy which the purchaser is contractually entitled to take during that month and which cannot be assigned:

(1) to a class of power which BPA delivers during such month pursuant to contracts between BPA and the purchaser; or

(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such month, shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

H. Coincidental Billing Adjustment

Purchasers of Priority Firm Power who are billed on a coincidental basis and who have diversity charges or diversity factors specified in their power sales contracts shall have their charges for billing demand adjusted according to the provisions of section III.C.6 of the GRSPs. Computed requirements purchasers are not subject to the Coincidental Billing Adjustment for scheduled power.

I. Energy Return Surcharge

Any purchaser who preschedules in accordance with sections 2(a)(4) and 2(c)(2) of Exhibit E of the power sales contract and who returns, during a single offpeak hour, more than 60 percent of the difference between that purchaser's computed peak requirement and computed average energy requirement for the billing month shall be subject to the following surcharge for each additional kilowatthour so returned:

1. 3.49 mills per kilowatthour for the months of April through October;

2. 1.48 mills per kilowatthour for the months of November through March.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the PF-89 rate is 78.5 percent FBS and 21.5 percent Exchange.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE IP-89

INDUSTRIAL FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available to direct-service industrial (DSI) customers for both the contract purchase of Industrial Firm Power and the purchase of Auxiliary Power if requested by the DSI customer and made available by BPA. If a DSI customer purchasing power under this rate schedule requests and BPA makes available power under another applicable wholesale rate schedule the IP-89 rate schedule is available for that portion of power purchased not covered under the alternative rate schedule. This rate schedule supersedes Schedule IP-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

The following rates shall be applied when first quartile service is provided under this rate schedule in accordance with the terms of a purchaser's Power Sales Contract dated August 25, 1981. A separate billing adjustment for the reserves provided by the purchasers of Industrial Firm Power is not contained in this rate schedule; the value of reserves credit has been included in the determination of the demand and energy charges.

Any contractual reference to the IP Premium Rate shall be deemed to refer to the demand and energy charges set forth below. Any reference to the IP Standard Rate shall be deemed to refer to the same demand and energy charges minus the Discount for Quality of Service.

A. <u>Demand Charge</u>

1. $4.14 per kilowatt of billing demand occurring during all Peak Period hours.

2. No demand charge during Offpeak Period hours.

B. <u>Energy Charge</u>

1. 19.5 mills per kilowatthour of billing energy for the billing months September through March;

2. 15.6 mills per kilowatthour of billing energy for the billing months April through August.

SECTION III. BILLING FACTORS

A. Billing Demand

The billing demand shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the BPA Operating Levels during the Peak Period for the billing month. The BPA Operating Level is defined in section III.A.10 of the General Rate Schedule Provisions (GRSPs). If BPA has agreed to serve a portion of a DSI load under an alternative rate schedule, the billing demand under the IP-89 rate schedule shall be specified in the contract initiating such arrangement.

However, if BPA has agreed, pursuant to section 4 of the direct-service industrial power sales contract, to sell Industrial Firm Power on a daily demand basis (transitional service), this section of the rate schedule shall not apply, and BPA shall bill the purchaser in accordance with the provisions of section V.C.3 of the GRSPs.

B. Billing Energy

The billing energy shall be the Measured Energy for the billing month, minus any kilowatthours on which BPA assesses the charge for unauthorized increase.

However, if BPA has agreed to serve only a portion of the DSI's load under the IP rate schedule, the billing energy for the power purchased under the IP rate shall be specified in the contract initiating such arrangement.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Discount for Quality of First Quartile Service

1. Application and Amount of First Quartile Discount

If a purchaser requests discounted rate service, a discount of 0.6 mills per kilowatthour of billing energy shall be granted. This billing credit shall be applied to the monthly billing energy under section III.B for all power purchased under this rate schedule. No credit shall be applied to those purchases subject to unauthorized increase charges under section IV.D of this rate schedule.

2. Eligibility Requirements for First Quartile Discount

To qualify for the First Quartile Discount the purchaser must request discounted rate service in writing by April 2 of each calendar year. By virtue of making such request, the Purchaser is agreeing to accept the level and quality of First Quartile service described in section 6 of the Variable Industrial Rate contract. Such acceptance includes the waiver of contract rights provided in section 6.a(2)(a) of said contract.

B. Curtailments

BPA shall charge the DSI for curtailments of the lower three quartiles in accordance with the provisions of section 9 of the power sales contract. BPA shall apply the demand charge in effect at the time of the curtailment in the computation of the amount of the curtailment charge. In the event that a purchaser is found to be eligible to have a portion of their load served under an alternative rate schedule, application of the curtailment charge shall be specified in the contract instituting such arrangement.

C. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all power purchases under this rate schedule.

Application of the Cost Recovery Adjustment Clause shall result in a uniform adjustment applied to the demand and energy charges, contained in sections II.A and II.B of this rate schedule, and the first quartile discount, if applicable, contained in section IV.A.1 of this rate schedule.

The uniform percentage (CRAC%) determined in Section III.C.5.c. of the GRSPs shall be applied in the following manner:

$$\left(1 + \frac{CRAC\%}{100}\right) * \frac{22.8}{23.5}$$ times the demand, energy, and first quartile discount charges.

where: 22.8 represents the average IP-89 margin-based rate in mills per kilowatthour, and 23.5 represents the average IP-89 floor rate in mills per kilowatthour.

D. Unauthorized Increase

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatthours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

E. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

F. <u>Outage Credit</u>

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any DSI for those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Industrial Firm Power. Such credit shall not be provided if BPA is able to serve the DSI's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the IP-89 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE SI-89

SPECIAL INDUSTRIAL POWER RATE

SECTION I. AVAILABILITY

This rate schedule is available to any DSI purchaser using raw minerals indigenous to the region as its primary resource and qualifying for this special power pursuant to the procedures established in section 7(d)(2) of the Northwest Power Act. This schedule is available for the contract purchase of this special class of industrial power and also for the purchase of Auxiliary Power if requested by the DSI and made available by BPA. The Special Industrial Offpeak rate available for Hanna Nickel Smelting Company pursuant to the Amendatory Agreement executed July 1, 1985, remains in force and is retained herein. Except for the Special Industrial Offpeak rate, schedule SI-89 supersedes schedule SI-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

This rate schedule contains the Standard Special Industrial Power Rate and the Special Industrial Offpeak Rate. The Standard Special Industrial Power Rate is available to any qualifying DSI for full service provided during all hours of the day. The Special Industrial Offpeak Rate is a lower rate available to the Hanna Nickel Smelting Company (Hanna) for service during periods specified by BPA. A separate billing adjustment for the value of the reserves provided by purchasers of this special class of Industrial Power is not contained in the rate schedule; the adjustment is reflected in the Standard Special Industrial Power Rate.

A. Standard Special Industrial Power Rate

1. Demand Charge

a. $3.08 per kilowattmonth of billing demand occurring during all Peak Period hours.

b. No demand charge during Offpeak Period hours.

2. Energy Charge

a. 16.9 mills per kilowatthour of billing energy for the billing months September through March;

b. 12.9 mills per kilowatthour of billing energy for the billing months April through August.

B. Special Industrial Offpeak Rate

1. Demand Charge

No demand charge in any hour of the day.

2. Energy Charge

7.0 mills per kilowatthour of billing energy during all billing months.

SECTION III. BILLING FACTORS

A. Billing Demand

1. Standard Special Industrial Power Rate

The billing demand for power purchased under the Standard Special Industrial Power Rate shall be the BPA Operating Level during the Peak Period as adjusted for power factor. If there is more than one BPA Operating Level during the Peak Period within a billing month, the billing demand shall be a weighted average of the Peak Period BPA Operating Levels for the billing month. The BPA Operating Level is defined in section III.A.10 of the General Rate Schedule Provisions (GRSPs).

However, if BPA has agreed, pursuant to section 4 of the direct-service industrial power sales contract, to sell Special Industrial Power on a daily demand basis (transitional service), this section of the rate schedule shall not apply, and BPA shall bill the purchaser in accordance with the provisions of section V.C of the GRSPs.

2. Special Industrial Offpeak Rate

There is no billing demand for purchases under the Special Industrial Offpeak rate.

B. Billing Energy

The billing energy under both the Standard Special Industrial and Special Industrial Offpeak Rates shall be the Measured Energy for the billing month, minus any kilowatthours on which BPA assesses the charge for unauthorized increase.

The kilowatthours of billing energy shall be prorated among the respective billing demands for the billing month.

SECTION IV. SELECTION OF THE SI-89 RATE FOR THE HANNA NICKEL SMELTING COMPANY

All purchasers, except for Hanna, shall purchase power under the Standard Special Industrial Power rate. Hanna shall have the option to select one of two types of service, standard service or offpeak service. In this case, BPA will provide standard service under the Standard Special Industrial Power Rate and offpeak service under the Special Industrial Offpeak Rate. Unless BPA receives a formal request from Hanna for service under the Special Industrial Offpeak Rate, all service will be standard service provided under the Standard Special Industrial Power Rate. To change the type of service provided and the associated rate, Hanna shall submit a formal request for service under the preferred rate option in accordance with the terms of the power sales contract providing for purchases under this rate schedule. Once Hanna has elected to purchase under one of the two options, all purchases of Special Industrial Power shall be subject to the terms and conditions of that rate option until such time that Hanna requests the other type of service.

SECTION V. SERVICE UNDER THE SPECIAL INDUSTRIAL OFFPEAK RATE

BPA shall designate the hours during which offpeak service will be available, and shall provide at least 2 weeks' notice before changing those designated hours. BPA shall identify at least 10 and up to 13 hours on each day Monday through Friday, 15 hours on Saturday, and 24 hours on Sunday, during which offpeak service will be available to the purchaser.

If Hanna has elected to be served under the Special Industrial Offpeak Rate, Hanna may request, during the designated offpeak periods, service in an amount not to exceed the purchaser's Contract Demand. During all other hours Hanna shall curtail service to a level not to exceed 15 percent of Contract Demand.

SECTION VI. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Curtailments

BPA shall charge the DSI for curtailments in accordance with the provisions of the DSI's power sales contract. Any curtailment charge levied shall be computed using the Standard Special Industrial Power Rate.

B. Unauthorized Increase Charge

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatthours associated with the DSI Measured Demand in any one 60-minute clock-hour, before adjustment for power factor, that exceed the BPA Operating Level for that clock-hour, regardless of whether such Measured Demand occurs during the Peak or Offpeak Period.

If BPA is providing service to Hanna under the Special Industrial Offpeak Rate, the amount by which Hanna's Measured Demand exceeds 15 percent of its Contract Demand during any hour other than the specified special hours shall be considered unauthorized increase.

C. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the GRSPs. The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment for service under the Standard Special Industrial Power Rate, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. For service under the Special Industrial Offpeak Rate, BPA shall increase the billing energy by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

D. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for those hours for which BPA is unable to deliver the full billing demand during that billing month due to an outage on the facilities used by BPA to deliver Special Industrial Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. In addition, no credit shall be applied to purchases under the Special Industrial Offpeak Rate. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

E. Extended Service Provision

The terms of this rate schedule may be extended for a period not to exceed June 30, 1990, in accordance with the Amendatory Agreement effective July 1, 1985, with the Hanna Nickel Smelting Company (Hanna). The Amendatory Agreement contains Hanna's agreement to make certain investments in a wet screening process at its Riddle facility.

SECTION VII. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The SI-89 rate is not based on the cost of resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE CF-89

FIRM CAPACITY RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of Firm Capacity without energy on a Contract Demand basis. This schedule is available only to those purchasers holding Firm Capacity contracts executed prior to July 1, 1985. It supersedes Schedule CF-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

$42.48 per kilowatt per year of Contract Demand, billed monthly at the rate of $3.54 per kilowattmonth of Contract Demand.

SECTION III. BILLING FACTORS

The billing demand shall be the Contract Demand.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Conservation Surcharge

The Conservation Surcharge shall be applied in accordance with section III.C.7 of the General Rate Schedule Provisions (GRSPs) and subsequent to any other rate adjustments.

B. Extended Peaking Surcharge

The monthly capacity rate specified in section II above shall be increased by the following extended peaking surcharge to compensate BPA for each hour that the purchaser's monthly demand duration exceeds 8 hours:

1. $0.0908 per kilowatt per hour of extended peaking for the months April through October;
2. $0.0512 per kilowatt per hour of extended peaking for the months November through March.

The charge shall be adjusted pro rata for each portion of an hour of extended peaking supplied to the purchaser.

The purchaser's monthly demand duration shall be determined by dividing:

1. the kilowatthours supplied to the purchaser under this rate schedule between the hours of 7 a.m. and 10 p.m. on the day of maximum kilowatthour use during those hours, provided such day is not a Sunday, by

2. the purchaser's Contract Demand for such month.

The purchaser's extended peaking shall be the amount by which the purchaser's monthly demand duration exceeds 8 hours. The extended peaking surcharge shall not be applied during periods when BPA does not require the delivery of peaking replacement energy by the purchaser.

C. Energy Return Surcharge

The energy associated with the delivery of Firm Capacity must be returned to BPA in accordance with the terms of the purchaser's Firm Capacity Contract. Unless waived by BPA, any purchaser whose energy returns during any single hour exceed 60 percent of the purchaser's Contract Demand during any single hour shall be subject to the following surcharge for each additional kilowatthour so returned:

1. 3.49 mills per kilowatthour for the months April through October, and

2. 1.48 mills per kilowatthour for the months November through March.

D. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all purchases under this rate schedule. The percentage increase calculated in sections III.C.5.c of the GRSPs shall be applied to the demand charges contained in section II of this rate schedule.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the CF-89 rate is 75.1 percent FBS and 24.9 percent Exchange for contract year service.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE CE-89

EMERGENCY CAPACITY RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of capacity:

A. when an emergency exists on the purchaser's system, or

B. when the purchaser wishes to displace higher-cost firm capacity resources which are otherwise available to meet the purchaser's load, provided the purchaser requests such capacity and BPA has capacity available for such purpose.

This schedule supersedes Schedule CE-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. Demand Charge

$1.06 per kilowatt of demand per calendar week or portion thereof.

B. Intertie Charge

The demand charge specified above shall be increased by $0.15 per kilowatt per week for capacity made available at the Oregon-California or Oregon-Nevada border for delivery over the Pacific Northwest-Pacific Southwest (Southern) Intertie.

SECTION III. BILLING FACTORS

The billing demand shall be the maximum amount requested by the purchaser and made available by BPA during a calendar week. If BPA is unable to meet subsequent requests by a purchaser for delivery at the demand previously established during such week, the billing demand for that week shall be the lower demand which BPA is able to supply.

SECTION IV. BILLING PERIOD

Bills shall be rendered monthly.

SECTION V. SPECIAL PROVISION

Energy delivered with such capacity shall be returned to BPA within 7 days of the date of delivery and shall be returned at times and rates of delivery agreed to by both the purchaser and BPA prior to delivery. BPA may agree to accept the return energy after the normal 7 day return period provided that such delay has been mutually agreed upon prior to delivery.

SECTION VI. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the CE-89 rate is 75.1 percent FBS and 24.9 percent Exchange.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE NR-89

NEW RESOURCE FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of firm power or capacity to be used within the Pacific Northwest. New Resource Firm Power is available to investor-owned utilities (IOUs) under net requirements contracts for resale to ultimate consumers, direct consumption, or use in construction, test and start up, and station service. New Resource Firm Power also is available to any public body, cooperative, or Federal agency to the extent such power is needed to serve any New Large Single Load. In addition, BPA may make this rate available to those parties participating in exchange agreements that use this rate schedule as the basis for determining the amount or value of power to be exchanged. This schedule supersedes Schedule NR-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. Demand Charge

1. $4.13 per kilowatt-month of billing demand occurring during all Peak Period hours.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

1. 25.5 mills per kilowatthour of billing energy for the billing months September through March;

2. 21.2 mills per kilowatthour of billing energy for the billing months April through August;

SECTION III. BILLING FACTORS

In this section billing factors are listed for computed requirements purchasers (section III.A) metered requirements purchasers, and those purchasers not covered by section III.A. (section III.B.).

A. Computed Requirements Purchasers

Purchasers designated by BPA as computed requirements purchasers pursuant to power sales contracts shall be billed in accordance with the provisions of this section.

1. Billing Demand

The billing demand for actual, planned, and contracted computed requirements purchasers shall be the higher of the billing factors "a" and "b," below:

a. the lower of:

(1) the larger of the Computed Peak Requirement or the Computed Average Energy Requirement;

(2) the Measured Demand, before adjustment for power factor; or

b. the lower of:

(1) the Computed Peak Requirement; or

(2) 60 percent of the highest Computed Peak Requirement during the previous 11 billing months (Ratchet Demand).

2. Billing Energy

The billing energy for actual, planned, and contracted computed requirements purchasers shall be:

a. for the months September through March, the sum of:

(1) 56 percent of the Measured Energy, and

(2) 44 percent of the Computed Energy Maximum;

b. for the months April through August, the sum of:

(1) 39 percent of the Measured Energy, and

(2) 61 percent of the Computed Energy Maximum.

B. Metered Requirements Purchasers and Other Purchasers Not Covered By Section III.A, Above

Purchasers designated as metered requirements customers and purchasers taking power under this rate schedule who are not otherwise covered by section III.A shall be billed as follows:

1. Billing Demand

The billing demand shall be the Measured Demand as adjusted for power factor, unless otherwise specified in the power sales contract. However, purchasers who previously used the Firm Energy rate schedule, FE-2, either in the computation of their power bills or in the determination of the value of an exchange account, shall not be charged for demand under this rate schedule.

2. Billing Energy

The billing energy shall be the Measured Energy, unless otherwise specified in the power sales contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

A. Power Factor Adjustment

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

B. Cost Recovery Adjustment Clause

The Cost Recovery Adjustment Clause described in section III.C.5 of the GRSPs shall be applied to all purchases and exchanges under this rate schedule. The percentage increase calculated in section III.C.5.c of the GRSPs shall be applied uniformly to the demand and energy charges contained in section II.A and II.B and the irrigation discount contained in section IV.C of this rate schedule. An additional increase of .046 mills per kilowatthour shall be made to the irrigation discount for each percentage increase in the NR rates due to the Cost Recovery Adjustment Clause.

C. Irrigation Discount

BPA shall apply an irrigation discount, equal to 4.6 mills per kilowatthour, to the charges for qualifying energy purchased under this rate schedule. The irrigation discount shall be applied after calculation of the Low Density Discount. The discount shall apply only to energy purchased during the billing months of April through October. Eligibility for the irrigation discount and reporting requirements shall be determined pursuant to section III.C.4 of the GRSPs.

D. Conservation Surcharge

The Conservation Surcharge shall be applied in accordance with section III.C.7 of the GRSPs and subsequent to any other rate adjustments.

E. Unauthorized Increase

BPA shall apply the charge for Unauthorized Increase to any purchaser of New Resource Firm Power taking demand and/or energy in excess of its contractual entitlement.

1. Rate for Unauthorized Increase

67.3 mills per kilowatthour.

2. Calculation of the 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. BPA shall first determine the amount of unauthorized increase related to demand and shall then treat any remaining unauthorized increase as energy-related.

a. Unauthorized Increase in Demand

That portion of any Measured Demand during Peak Period hours, before adjustment for power factor, that exceeds the demand which the purchaser is contractually entitled to take during the billing month and that cannot be assigned:

(1) to a class of power which BPA delivers on such hour pursuant to contracts between BPA and the purchaser; or

(2) to a type of power which the purchaser acquires from sources other than BPA and which BPA delivers during such hour, shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) if such exhibit does not apply or is not a part of the purchaser's power sales contract, at the rate for Unauthorized Increase, based on the amount of energy associated with the excess demand.

b. Unauthorized Increase in Energy

The amount of Measured Energy during a billing month that exceeds the amount of energy which the purchaser is contractually entitled to take during that month and that cannot be assigned:

(1) to a class of power that BPA delivers during such month pursuant to contracts between BPA and the purchaser; or

(2) to a type of power that the purchaser acquires from sources other than BPA and that BPA delivers during such month, shall be billed:

(1) in accordance with the provisions of the "Relief from Overrun" exhibit to the power sales contract; or

(2) as unauthorized increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

F. Coincidental Billing Adjustment

Purchasers of New Resource Firm Power who are billed on a coincidental basis and who have diversity charges or diversity factors specified in their power sales contracts shall have their charges for billing demand adjusted according to the provisions of section III.C.6 of the GRSPs. Computed requirements purchasers are not subject to the Coincidental Billing Adjustment for scheduled power.

G. Outage Credit

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any purchaser for those hours for which BPA is unable to deliver the full billing demand during the billing month due to an outage on the facilities used by BPA to deliver New Resource Firm Power. Such credit shall not be provided if BPA is able to serve the purchaser's load through the use of alternative facilities or if the outage is for less than 30 minutes. The amount of the credit shall be calculated according to the provisions of section III.C.2 of the GRSPs.

H. Energy Return Surcharge

Any purchaser who preschedules in accordance with sections 2(a)(4) and 2(c)(2) of Exhibit E of the Power Sales contract and who returns, during a single offpeak hour, more than 60 percent of the difference between that purchaser's estimated computed peak requirement and estimated computed average energy requirement for the billing month shall be subject to the following surcharge for each additional kilowatthour so returned:

1. 3.49 mills per kilowatthour for the months of April through October, and

2. 1.48 mills per kilowatthour for the months of November through March.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the NR-89 rate is 100.0 percent Exchange.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE SP-89

SHORT-TERM SURPLUS FIRM POWER RATE

SECTION I. AVAILABILITY

This rate schedule is available for the purchase of Surplus Firm Power for the period ending September 30, 1994, including purchases under the Western Systems Power Pool (WSPP) agreements. BPA is not obligated to make power or energy available under this rate schedule if such power or energy would displace sales under the IP-89, VI-87, PF-89, or NR-89 rate schedules. Schedule SP-89 supersedes schedule SP-87 and associated GRSPs, except in the case of contracts for sales under schedule SP-87 which become effective on or before September 30, 1989. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. Contract Rate

1. Demand Charge

a. For contracts that specify 12 months of service per year, \$51.48 per kilowatt per year of Contract Demand billed monthly at the rate of \$4.29 per kilowatt of Contract Demand occurring during all Peak Period hours in each billing month.

b. For contracts that specify service for fewer than 12 months per year, the monthly demand charge shall be assessed only for the specified service months at the rate of \$4.29 per kilowatt of Billing Demand occurring during the Peak Period plus:

$$\frac{\$4.29\ (12 - \text{specified service months})\ .25}{\text{specified service months}}$$

c. No demand charge during Offpeak Period hours

2. Energy Charge

24.3 mills per kilowatthour of Billing Energy.

B. Flexible Rate

Energy charges or demand and energy charges may be specified at a higher or lower average rate as mutually agreed by BPA and the purchaser. In no case shall the rate exceed 100 percent of the fixed and variable unit costs of generation and transmission of BPA's highest cost resource including exchange resources. No resource cost determination is needed for sales at less than or equal to the Contract rate.

C. Intertie Charge

Rates in sections II.A and II.B that equal or exceed the Contract rate shall be increased by the following charges for transactions over the Pacific Northwest-Pacific Southwest Intertie.

1. $.36 per kilowatt per month of billing demand and

2. 0.69 mills per kilowatthour of billing energy.

Rates in section II.B having an energy-only charge that equals or exceeds 30.2 mills per kilowatthour shall be increased by 1.4 mills per kilowatthour for transactions over the Pacific Northwest-Pacific Southwest Intertie.

SECTION III. BILLING FACTORS

The billing factors shall be the Measured Demand and Measured Energy, unless otherwise specified in the contract.

SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

Power Factor Adjustment

The adjustment for power factor for BPA customers that are billed for Short-Term Surplus Firm Power on metered amounts, when specified in this rate schedule or in the contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand or energy by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the SP-89 rate is 99.3 percent Exchange and 0.7 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE NF-89

NONFIRM ENERGY RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of nonfirm energy to be used both inside and outside the United States including sales under the Western Systems Power Pool (WSPP) agreements and sales to consumers. This schedule also applies to energy delivered for emergency use under the conditions set forth in section V.A of the General Rate Schedule Provisions (GRSPs). BPA is not obligated to offer nonfirm energy to any purchaser that results in displacement of firm power purchases under BPA's Power Sales Contracts. The offer of nonfirm energy under this schedule shall be determined by BPA. Schedule NF-89 supersedes Schedule NF-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATES

The average cost of nonfirm energy is 18.0 mills per kilowatthour. The NF-89 rate schedule provides for upward and downward pricing flexibility from this average nonfirm energy cost. All rates and any subsequent adjustments contained in this rate schedule shall not exceed in total the NF Rate Cap defined in section IV.C of the GRSPs.

A. Standard Rate

The Standard rate is any offered rate not to exceed 21.6 mills per kilowatthour.

B. Market Expansion Rate

The Market Expansion rate is any offered rate below the Standard rate in effect. BPA may have one or more Market Expansion rates in effect simultaneously.

C. Incremental Rate

The Incremental rate is the Incremental Cost of energy plus 2.0 mills per kilowatthour, where the Incremental Cost is defined as all identifiable costs (expressed in mills per kilowatthour) that BPA would have avoided had it not produced or purchased the energy being sold under this rate.

D. Contract Rate

The Contract rate is 14.9 mills per kilowatthour of billing energy.

SECTION III. ADJUSTMENTS TO RATES

A. Guaranteed Delivery Surcharge

A surcharge of 2.0 mills per kilowatthour of billing energy is applied to guaranteed delivery of nonfirm energy under the Standard rate and Market Expansion rate.

B. Intertie Charge

Rate offers, under any of the rates specified above, greater than or equal to 18.0 mills per kilowatthour shall be increased by 1.4 mills per kilowatthour for nonfirm energy scheduled for delivery over the Pacific Northwest-Pacific Southwest Intertie.

SECTION IV. BILLING FACTORS

The billing energy for nonfirm energy purchased under this rate schedule shall be the Measured Energy unless otherwise specified by contract.

SECTION V. APPLICATION AND ELIGIBILITY

Any time that BPA has nonfirm energy for sale, the Standard rate, the Market Expansion rate, the Incremental rate, the Contract rate, or a combination of these rates may be in effect.

A. Standard Rate

The Standard rate:

1. is available for all purchases of nonfirm energy; and

2. applies to nonfirm energy purchased pursuant to the Relief from Overrun Exhibit to the power sales contract.

B. Market Expansion Rate

1. Application of the Market Expansion rate

The Market Expansion rate applies when BPA determines that all markets at the Standard rate have been satisfied and BPA offers additional nonfirm energy.

2. Market Expansion Rate Qualification Criteria

In order to purchase nonfirm energy at the Market Expansion rate, a purchaser must:

a. have a displaceable resource, displaceable purchase of electricity, or

b. be an end-user load with a displaceable alternative fuel source.

In addition, a purchaser must demonstrate one of the following:

a. shutdown or reduction of the output of the displaceable resource in an amount equal to the amount of Market Expansion rate energy purchased; or

b. reduction of a displaceable purchase and the output of the resource associated with that purchase, in an amount equal to the amount of Market Expansion rate energy purchased; or

c. shutdown or reduction of the identified output of the resource(s) indirectly in an amount equal to the amount of Market Expansion rate energy purchased (for example, the purchase may be used to run a pumped storage unit); or

d. decrease of an end-user alternate fuel source in an amount equivalent to the amount of Market Expansion rate energy purchased.

3. <u>Eligibility Criteria for Market Expansion rate</u>

a. When only one Market Expansion rate is offered:

Purchasers qualifying under section V.B.2. who purchased nonfirm energy directly from BPA are eligible to purchase power under the Market Expansion rate offered if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.0 mills per kilowatthour.

Purchasers qualifying under section V.B.2. who purchase nonfirm energy through a third party are eligible to purchase power under the Market Expansion rate offered if the cost of the qualifying alternative fuel source is lower than the Standard rate in effect plus 4.0 mills per kilowatthour.

b. When more than one Market Expansion rates are offered:

Purchasers qualifying under section V.B.2. who purchase nonfirm energy directly from BPA are eligible to purchase power under the Market Expansion rate if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.0 mills per kilowatthour. The rate applicable to a purchaser shall be the highest Market Expansion rate offered that is below the purchaser's qualifying decremental cost minus 2.0 mills per kilowatthour.

Purchasers qualifying under section V.B.2. who purchase nonfirm energy through a third party are eligible to purchase power under the Market Expansion rate if the decremental cost of the qualifying alternative fuel source is lower than the Standard rate plus 4.0 mills per kilowatthour. The rate applicable to a purchaser shall be the highest Market Expansion rate offered that is below purchaser's qualifying decremental cost minus 4.0 mills per kilowatthour.

C. Incremental Rate

The Incremental rate applies to sales of energy:

1. that is produced or purchased by BPA concurrently with the nonfirm energy sale;

2. that BPA may at its option not produce or purchase; and

3. that has an Incremental Cost greater than the Standard rate (plus the Intertie Charge, if applicable) less 2.0 mills per kilowatthour.

D. Contract Rate

The Contract rate applies to contracts (except power sales contracts offered pursuant to sections 5(b), 5(c), and 5(g) of the Northwest Power Act) that refer to the Contract rate:

1. for the sale of nonfirm energy; or

2. for determining the value of energy.

E. Western Systems Power Pool Transactions

BPA may make available nonfirm energy for transactions under the Western Systems Power Pool (WSPP) agreement. WSPP sales shall be subject to the terms and conditions specified in the WSPP agreement and shall be consistent with regional and public preference. The rate for transactions under the WSPP agreement is any rate within the limits specified by the Standard, Market Expansion, and Incremental rates but may differ from the actual rate offered for non-WSPP transactions in any hour. The rate for WSPP transactions is independent of any other rate offered concurrently under this rate schedule outside that agreement.

F. End-User Rate

BPA may agree to a rate or rate formula for nonfirm energy purchases by end-users. Such rate or rate formula shall be within the limits specified for the Standard and Market Expansion rates but may differ from the actual rates offered during any hour.

SECTION VI. DELIVERY

A. Rate of Delivery

BPA shall determine the amount of nonfirm energy to be made available for each hour. Such determination shall be made for each applicable nonfirm energy rate.

B. Guaranteed Delivery

1. Availability

BPA will determine the amount and duration of nonfirm energy to be offered on a guaranteed basis. Such daily or hourly amounts may be as small as zero or as much as all the nonfirm energy that BPA plans to offer for sale on such days.

2. Conditions

Scheduled amounts of guaranteed nonfirm energy may not be changed except:

a. when BPA and the purchaser mutually agree to increase or decrease the scheduled amounts; or

b. when BPA must reduce nonfirm energy deliveries in order to serve firm loads because of unexpected generation or transmission losses.

SECTION VII. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The approximate cost contribution of different resource categories to the average cost of nonfirm energy is 99.6 percent FBS and 0.4 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE SS-89

SHARE-THE-SAVINGS RATE

SECTION I. AVAILABILITY

This rate schedule is available for the contract purchase of Nonfirm Energy under an experimental rate and is limited to the term of the rate experiment. Nonfirm Energy will be made available under this rate schedule for use both inside and outside the United States for the displacement of a qualifying resource, displaceable purchase of electricity, or end-user load that can be served with alternate fuel sources. This rate schedule is only available to purchasers who execute a contract with BPA specifying use of the Share-the-Savings Rate. BPA is not obligated to offer Nonfirm Energy to any purchaser that results in displacement of firm power purchases under BPA's Power Sales Contracts. Schedule SS-89 supersedes Schedule SS-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

The rate shall be a formula rate based solely or in part on decremental cost information submitted by the purchaser. The rate formula and decremental cost, for purposes of establishing charges under this rate schedule, shall be defined in the applicable contract. The rate formula agreed upon by BPA and the purchaser shall in no event result in a rate higher than the NF Rate Cap defined in section IV.C. of the GRSPs or lower than 1 mill per kilowatthour.

SECTION III. BILLING FACTORS

The billing energy for Nonfirm Energy purchased under this rate schedule shall be the Measured Energy unless otherwise specified in the Share-the-Savings Rate contract.

SECTION IV. APPLICATION AND ELIGIBILITY

A. <u>General Requirements</u>

In order to purchase Nonfirm Energy under the Share-the-Savings Rate, the purchaser must:

1. have executed a contract specifying application of the Share-the-Savings Rate Schedule.

2. have a displaceable resource, displaceable purchase of electricity, or be an end-user load with a displaceable alternate fuel source. End-user loads with alternate fuel sources may not use the Decremental Cost of a displaceable purchase of electricity to qualify for this rate.

B. <u>BPA Service Priority</u>

Offers of Nonfirm Energy under this rate schedule shall be made pursuant to the terms and conditions set forth in the Share-the-Savings rate contract. BPA will sell Nonfirm Energy under this rate schedule consistent with regional and public preference.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The SS-89 rate is not based on the cost of BPA resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

SCHEDULE RP-89

RESERVE POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of power:

A. in cases where a purchaser's power sales contract states that the rate for Reserve Power shall be applied;

B. for which BPA determines no other rate schedule is applicable; and

C. to serve a purchaser's firm power load in circumstances where BPA does not have a power sales contract in force with such purchaser, and BPA determines that this rate should be applied.

This rate schedule may be applied to power purchased by entities outside the United States. This rate schedule supersedes Schedule RP-87 which went into effect on an interim basis on October 1, 1987. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

SECTION II. RATE

A. Demand Charge

1. $3.64 per kilowatt of billing demand occurring during all Peak Period hours.

2. No demand charge during Offpeak Period hours.

B. Energy Charge

25.3 mills per kilowatthour of billing energy.

SECTION III. BILLING FACTORS

The factors to be used in determining the billing for power purchased under this rate schedule are as follows:

A. Billing Demand

If applicable, the billing demand shall be the Contract Demand as specified in the power sales contract. Otherwise the billing demand shall be the Measured Demand as adjusted for power factor.

B. Billing Energy

The billing energy shall be the Contract Demand multiplied by the number of hours in the billing month, if use of the Contract Demand for determining billing energy is specified in the power sales contract. Otherwise the billing energy for such purchasers shall be the Measured Energy.

SECTION IV. POWER FACTOR ADJUSTMENT

The adjustment for power factor, when specified in this rate schedule or in the power sales contract, shall be made in accordance with the provisions of both this section and section III.C.1 of the General Rate Schedule Provisions (GRSPs). The adjustment shall be made if the average leading power factor or average lagging power factor at which energy is supplied during the billing month is less than 95 percent.

To make the power factor adjustment, BPA shall increase the billing demand by 1 percentage point for each percentage point or major fraction thereof (0.5 or greater) by which the average leading power factor or average lagging power factor is below 95 percent. BPA may elect to waive the adjustment for power factor in whole or in part.

SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

A. The RP-89 rate is not based on the cost of resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 17.7 mills per kilowatthour.

C. The forecasted cost of resources to meet load growth is 28.7 mills per kilowatthour.

OUTLINE FOR GENERAL RATE SCHEDULE PROVISIONS

SECTION I. ADOPTION OF REVISED RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A. Approval of Rates

These 1989 rate schedules and General Rate Schedule Provisions (GRSPs) shall become effective upon interim approval or final confirmation and approval by the Federal Energy Regulatory Commission (FERC). BPA will request FERC approval effective October 1, 1989. BPA proposes that the following schedules, and the GRSPs associated with these schedules, be effective for 2 years: PF-89, IP-89, SI-89, CE-89, CF-89, NR-89, SS-89, SP-89, NF-89, and RP-89. The VI-87 rate schedule reflects adjustments of and supplements to the rate schedule VI-86 and associated GRSPs (which are to be in effect for 7 years). Sections III.A and VI.J of the VI-87 rate schedule are to be in effect for an additional 2 years. BPA proposes that rate schedule SI-89 be effective 2 years, except for the Special Industrial Offpeak rate provision, which is to remain in effect through June 30, 1990, pursuant to an Amendatory Agreement between BPA and Hanna Nickel Smelting Company executed July 1, 1985. BPA proposes that the SP-89 rate schedule, and the GRSPs associated with this schedule, be effective for 5 years.

B. General Provisions

These 1989 rate schedules, and the GRSPs associated with these rate schedules, supersede BPA's 1987 rate schedules (which became effective October 1, 1987) to the extent stated in the Availability section of each 1989 rate schedule. These schedules and GRSPs shall be applicable to all BPA contracts, including contracts executed both prior to and subsequent to enactment of the Northwest Power Act. All sales of power made under these rate schedules are subject to the following acts as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Northwest Power Act.

SECTION II. TYPES OF BPA SERVICE

A. Priority Firm Power

Priority Firm Power is electric power (capacity, energy, or capacity and energy) that BPA will make continuously available for resale to ultimate consumers, or for direct consumption, construction, test and start-up, and station service by public bodies, cooperatives, and Federal agencies. (Construction, test and start-up, and station service are defined in section V.B of these GRSPs.)

Utilities participating in the exchange under section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to their Residential Purchase and Sale Agreements.

In addition, BPA may make Priority Firm Power available to those parties participating in exchange agreements specifying use of the Priority Firm rate for determining the amount or value of power to be exchanged.

Power purchased under the power rate schedule is to be used to meet the purchaser's actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSPs (section V.E). However, BPA shall not restrict Priority Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSPs.

Priority Firm Power is not available to serve New Large Single Loads.

B. <u>New Resource Firm Power</u>

New Resource Firm Power is electric power (capacity, energy, or capacity and energy) that BPA will make continuously available:

1. for any New Large Single Load,

2. for firm power purchased by investor-owned utilities pursuant to power sales contracts with BPA, and

3. for construction, test and start-up, and station service for facilities owned or operated by investor-owned utilities.

New Resource Firm Power is to be used to meet the purchaser's actual firm load within the Pacific Northwest. Such power may be restricted in accordance with the Restriction of Deliveries section of these GRSPs (section V.E). However, BPA shall not restrict New Resource Firm Power until Industrial Firm Power has been restricted in accordance with the provisions of section II.C of these GRSPs.

C. <u>Industrial Firm Power</u>

Industrial Firm Power is electric power that BPA will make continuously available to a direct-service industrial (DSI) purchaser pursuant to the DSI's power sales contract and subject to:

1. the restriction applicable to deliveries of all firm power pursuant to the Uncontrollable Forces and Continuity of Service provisions of the General Contract Provisions of the power sales contract, and

2. the restrictions given in the Restriction of Deliveries section of the power sales contract.

D. <u>Special Industrial Power</u>

Special Industrial Power is electric power which BPA will make continuously available to any DSI that qualifies for the Special Industrial Power rate pursuant to section 7(d)(2) of the Northwest Power Act. This power is similar in nature to Industrial Firm Power, but is subject to greater restriction by BPA. Special Industrial Power is made available to the qualifying DSI upon adoption of, and subject to, an amendment modifying its power sales contract.

E. Auxiliary Power

Auxiliary Power is that power which a DSI requests and which BPA agrees to make available to serve that portion of the DSI's load which is in excess of the DSI's Operating Demand for Industrial Firm Power or Special Industrial Power.

F. Firm Capacity

Firm Capacity is capacity that BPA assures will be available in the amount(s) and during the period(s) specified in the power sales contract. The energy associated with this capacity must be returned to BPA. Firm Capacity may be restricted pursuant to the Restriction of Deliveries section of these GRSPs (section V.E).

G. Surplus Firm Power

Surplus Firm Power is firm energy, firm power (firm energy with capacity), and firm capacity (capacity with energy return requirements) in excess of the amount required to meet BPA's existing contractual obligations to provide firm service. Surplus Firm Power may be used either for resale or direct consumption by purchasers both inside and outside the United States. Such power, however, may be restricted pursuant to the Restriction of Deliveries section of these GRSPs (section V.E).

H. Nonfirm Energy

Nonfirm Energy is supplied or made available by BPA to a purchaser under an arrangement that does not have the guaranteed continuous availability feature of firm power. Nonfirm energy is mostly sold under the Nonfirm Energy rate schedule, NF-89. Nonfirm energy also may be supplied under the Share-the-Savings rate schedule, SS-89, which is available as an experimental rate for contract purchase.

In addition, BPA also can make nonfirm energy available under the Nonfirm Energy rate schedule to the Western Systems Power Pool (WSPP) subject to terms and conditions agreed upon by the members participating in the WSPP and in accordance with BPA policy for such arrangements.

However, Nonfirm Energy that has been purchased under a guarantee provision in the Nonfirm Energy rate schedule shall be provided to the purchaser in accordance with the provisions of that schedule and the power sales contract if applicable. BPA may make Nonfirm Energy available to purchasers both inside and outside the United States.

I. Reserve Power

Reserve Power is firm power sold to a purchaser:

1. in cases where the purchaser's power sales contract states that the rate for Reserve Power shall be applied;

2. to provide service when no other type of power is deemed applicable; and

3. to serve the purchaser's firm power loads under circumstances where BPA does not have a power sales contract in force with the purchaser.

Sales of Reserve Power are subject to the Restriction of Deliveries section of these GRSPs (section V.E).

SECTION III. BILLING FACTORS AND BILLING ADJUSTMENTS

A. Billing Factors for Demand

1. Measured Demand

The purchaser's Measured Demand shall be determined in the manner described in this section. Measured Demand shall be that portion of the metered or scheduled demand that is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and that 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 clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract. The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power.

The Measured Demand shall be determined from the metered demand or the scheduled demand, as hereinafter defined. The Measured Demand shall be determined on either a coincidental or a noncoincidental basis, as provided in the purchaser's power sales contract.

a. Metered Demand

The metered demand in kilowatts shall be the largest of the 60-minute clock-hour integrated demands, adjusted as specified in the power sales contract, at which electric energy is delivered to a purchaser:

(1) at each point of delivery for which the metered demand is the basis for determination of the Measured Demand,

(2) during each time period specified in the applicable rate schedule, and

(3) during any billing period.

Such largest integrated demand shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.A herein. In determining the metered demand, BPA shall exclude any abnormal integrated demands due to or resulting from:

(1) emergencies or breakdowns on, or maintenance of, the Federal system facilities, and

(2) emergencies on the purchaser's facilities, provided that such facilities have been adequately maintained and prudently operated, as determined by BPA.

b. Scheduled Demand

The scheduled demand in kilowatts shall be the largest of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

(1) to each system for which scheduled demand is the basis for determination of the Measured Demand,

(2) during each time period specified in the applicable rate schedule, and

(3) during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining billing demand.

2. Ratchet Demand

The Ratchet Demand in kilowatts shall be the maximum demand established during a specified period of time either during or prior to the current billing period. The demand on which the ratchet is based is specified in the relevant rate schedule or in these GRSPs. For utilities purchasing under the PF or NR rate schedules, the Ratchet Demand is based on the highest demand during prior billing months. When the Ratchet Demand is used as a billing factor, BPA shall have specified in the appropriate schedules or GRSPs:

a. the period of time over which the ratchet shall be calculated,

b. the type of demand to be used in the calculation, and

c. the percentage (if any) of that demand which will be used to calculate the Ratchet Demand.

3. Contract Demand

The Contract Demand shall be the maximum number of kilowatts that the purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the power sales contract. BPA may agree to make deliveries at a rate in excess of the Contract Demand at the request of the purchaser, but shall not be obligated to continue such excess deliveries. Any contractual or other reference to Contract Demand as expressed in kilowatthours shall be deemed, for the purpose of these GRSPs, to refer to the term "Contract Energy."

4. Computed Peak Requirement

For purchasers designated to purchase on the basis of computed requirements, the Computed Peak Requirement shall be determined as specified in the purchaser's power sales contract. That specification is provided in:

a. sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers;

b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers; and

c. sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

5. Computed Average Energy Requirement

For computed requirements purchasers, the Computed Average Energy Requirement shall be determined as specified in the purchaser's power sales contract. That specification is provided in:

a. sections 16, 17(c), and 17(f), as adjusted by other sections of the contract, for actual computed requirements purchasers;

b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for planned computed requirements purchasers; and

c. sections 16 and 17(b), as adjusted by other sections of the contract, for contracted computed requirements purchasers.

6. Operating Demand

The Operating Demand is that demand which is established by each DSI in accordance with section 5(b) of the DSI's power sales contract. Unless the DSI has requested, and BPA has granted, an Auxiliary Demand, the Operating Demand establishes a limit with respect to:

a. the demand which the purchaser may impose on BPA; and

b. the total amount of energy during a billing month which the DSI is entitled to purchase from BPA.

7. Curtailed Demand

A Curtailed Demand is the number of kilowatts of industrial power (Industrial Firm Power or Special Industrial Power) during the billing month which results from the DSI's request for such power in amounts less than the Operating Demand therefor. Each purchaser of industrial power may curtail its demand according to the terms of its power sales contract (which permits up to three levels of Curtailed Demand each month).

8. Restricted Demand

Restricted Demand is the number of kilowatts of industrial power (either Industrial Firm Power or Special Industrial Power) that results when BPA has restricted delivery of such power for one clock-hour or more. BPA shall make such restrictions according to the terms of the DSI's power sales contract. In a given billing month, there are as many possible levels of Restricted Demand for a DSI as there are number of restrictions.

9. Auxiliary Demand

Auxiliary Demand is the number of kilowatts of Auxiliary Power that a DSI requests and that BPA agrees to make available to serve a portion of the DSI's load during the period specified in the DSI's request. The DSI may request up to three levels of Auxiliary Demand during a billing month.

If BPA agrees to a request for Auxiliary Power but later becomes unable to supply such demand, the Restricted Demand for Auxiliary Power is deemed to be the Auxiliary Demand for such period of restriction. Auxiliary Power may be curtailed by the DSI according to the provisions of section 9(a) of the DSI's power sales contract.

BPA shall make Auxiliary Power available to Industrial Firm Power purchasers under the Industrial Firm Power Rate Schedule at the Standard Industrial Rate. Auxiliary Power sales to DSIs electing to purchase under the Variable Industrial Power Rate Schedule (VI-87) shall be made at the rate determined pursuant to section III of the VI-87 rate schedule. Auxiliary Power sales to DSIs purchasing under the Special Industrial Rate will be made only at the Standard Special Industrial Power Rate.

10. BPA Operating Level

The BPA Operating Level is, for the purpose of these rate schedules and GRSPs, an hourly amount of industrial power (Industrial Firm Power or Special Industrial Power) for a DSI that is equal to the lowest of the following demands during that hour:

a. Operating Demand plus Auxiliary Demand, if any;

b. Curtailed Demand; or

c. Restricted Demand.

The weighted average BPA Operating Level for each DSI can be determined by summing the hourly BPA Operating Levels and dividing by the number of hours in the billing month.

Each DSI must request service from BPA for each billing month in accordance with the terms of the power sales contract. The requested level of service will be the BPA Operating Level, provided BPA does not need to restrict the DSI and provided BPA agrees to supply any requested Auxiliary Demand. Each requested level of service may include a designation for both the Peak Period and the Offpeak Period. A DSI may request and BPA may agree to a level of service for the Offpeak Periods other than that in the Peak Period. If a DSI does not separately designate a requested level of service for the Peak and Offpeak Periods, the BPA Operating Level is the basis for determining if a DSI has incurred an unauthorized increase.

Any DSI whose Measured Demand, before adjustment for power factor, during any 1 hour exceeds the BPA Operating Level for that hour shall be subject to unauthorized increase charges for each kilowatthour of unauthorized increase associated with each overrun.

Only the BPA Operating Level applicable during the Peak Period will be used in determining the Billing Demand for power purchased under the Industrial Firm Power rate schedule, the Variable Industrial Power rate schedule, and the Standard Rate under the Special Industrial rate schedule. During the Peak Period the BPA Operating Level may be no greater than the Operating Demand for the billing month unless the customer has requested, and BPA has agreed to supply, the Auxiliary Demand.

B. Billing Factors for Energy

1. Measured Energy

Measured Energy shall be that portion of the metered or scheduled energy that is purchased from BPA under the applicable rate schedule. For those contracts to which BPA is a party and that 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 clock-hour integrated demand assigned to any class of power shall be determined pursuant to the power sales contract. The sum of the portions of the demands so assigned shall constitute the Measured Energy for each such class of power.

The Measured Energy shall be determined from the metered energy or the scheduled energy, as hereinafter defined.

a. Metered Energy

The metered energy for a purchaser shall be the number of kilowatthours that are recorded on the appropriate metering equipment, adjusted as specified in the power sales contract, and delivered to a purchaser:

(1) at all points of delivery for which metered energy is the basis for determination of the Measured Energy, and

(2) during any billing period.

The metered energy shall be determined from measurements made either in the manner specified in the power sales contract or as provided in section VI.A herein.

b. Scheduled Energy

The scheduled energy in kilowatthours shall be the sum of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

(1) for each system for which scheduled energy is the basis for determination of the Measured Energy, and

(2) during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining billing energy.

2. Computed Energy Maximum

The Computed Energy Maximum equals the product of the number of hours in the billing month and the Computed Average Energy Requirement.

3. Contract Energy

The Contract Energy shall be the maximum number of kilowatthours that the purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the power sales contract.

C. Billing Adjustments

1. Power Factor Adjustment

The formula for determining average power factor is as follows:

$$\text{Average Power Factor} = \frac{\text{Kilowatthours}}{\sqrt{(\text{Kilowatthours})^2 + (\text{Reactive kilovoltamperehours})^2}}$$

The data used in the above formula shall be obtained from meters that are ratcheted to prevent reverse registration. These data then shall be adjusted for losses, if applicable, before determination of the average power factor.

When deliveries to a purchaser at any point of delivery either:

a. include more than one class of power, or

b. are provided under more than one rate schedule and it is impracticable to meter the kilowatthours and reactive kilovoltamperehours for each class or rate schedule separately, the average power factor of the total deliveries for the month will be used, where applicable, as the power factor for all power delivered to such point of delivery.

To maintain acceptable operating conditions on the Federal system, BPA may, unless specifically otherwise agreed, restrict deliveries of power to a purchaser with a low power factor. Such restriction may be made to a point of delivery or to a purchaser's system at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 75 percent.

2. Outage Credit

To the extent that BPA is unable to provide full service to a purchaser during the billing month as a result of interruptions in service due to reasons cited in the General Contract Provisions, BPA shall adjust the charges for those hours for billing demand for such purchaser to reflect BPA's inability to provide full service, provided such adjustment is mandated by the purchaser's power sales contract. The adjustment is provided on a point of delivery basis. To compute the adjustment for noncoincidentally billed systems, BPA shall determine the monthly demand charge(s) for the point(s) of delivery where the outage(s) occurred, multiply by the number of hours of outage, and divide by the total number of hours in the billing month. For coincidentally billed points of delivery, the adjustment shall apply only to those points of delivery at which BPA was unable to provide full service. For partial outages (such as an outage on one feeder in a substation with several feeders), BPA shall determine an equivalent interruption in order to arrive at the number of hours to be used in the calculation of the credit.

3. Low Density Discount (LDD)

a. Basic LDD Principles

A predetermined discount shall be applied each billing month to the charges for all power purchased under the Priority Firm Power rate schedule by eligible purchasers as defined in section b, below. The discount shall be calculated on an annual basis and shall become effective with the first billing period in the calendar year. Retroactive billing for the LDD may be required if the data are not available by the January billing date. The level of the discount shall be determined from the following ratios:

(1) the purchaser's total electric energy requirements during the previous calendar year (the purchaser's firm sales, nonfirm sales to firm retail loads, sales for resale, and associated losses, but excluding nonfirm sales to nonfirm retail loads, such as boiler loads served under BPA's alternate fuel policy) divided by the value of the purchaser's depreciated electric plant (excluding generation plant) at the end of such year, and

(2) the average number of consumers (annual and seasonal consumers with residential, industrial, commercial, and irrigation accounts, but excluding separately billed services for water heating, electric space heating, and security lights) during the previous calendar year divided by the number of pole miles of distribution line at the end of such year. Distribution lines are defined as those that deliver electric energy from a substation or metering point, at a voltage of 34.5 kV or less,

to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities.

These calculations shall be based on data provided in the purchaser's annual financial and operating report. In calculating these ratios, BPA shall use data pertaining to the purchaser's entire electric utility system within the region. Results of the calculations shall not be rounded.

Customers who have not provided BPA with all four requisite pieces of annual data (see a.(1) and a.(2) above) by June 30 of each year shall be declared ineligible for the LDD effective with the June billing period for that year. BPA shall extend a customer's eligibility from the previous year through the June billing period of the following year and shall make any necessary retroactive adjustments once the new data have been processed. If no data have been received by December 31 for the previous calendar year, BPA shall assume that the utility did not qualify for an LDD for that year. Low Density Discounts issued from January 1 to June 30 shall be assumed to have been in error, and the utility shall be billed for any such discounts issued.

Revisions to the data used to calculate the amount of the LDD may be made by the purchaser for a period of up to 2 years from the first day to which the data apply. However, such revisions shall not apply to periods when the customer was ineligible for a discount due to late data submission.

b. <u>Eligibility Criteria</u>

To qualify for a discount, the purchaser must meet all six of the following eligibility criteria:

(1) the purchaser must serve as an electric utility offering power for resale;

(2) the purchaser must agree to pass the benefits of the discount through to the purchaser's consumers within the region served by BPA;

(3) the purchaser's average retail rate for the reporting year must exceed the average Priority Firm Power rate in effect for the qualifying period by 10 percent. For CY 1989, the average Priority Firm Power rate shall be the average of the PF-87 Preference rate for 9 months and the PF-89 Preference rate for 3 months. For CY 1990, the average Priority Firm Power rate shall be the PF-89 Preference rate.

(4) the purchaser's kilowatthour-to- investment ratio (Ratio 3.a.(1)) must be less than 100;

(5) the purchaser's consumers-per-mile ratio (Ratio 3.a.(2)) must be less than 12; and

(6) the purchaser must qualify for a discount based on the criteria in section c, below.

c. Discounts

The purchaser shall be awarded the greatest discount for which that purchaser qualifies. The discounts and the qualifying criteria for those discounts are listed below.

(1) Three percent, for any purchaser for whom:

(a) the kilowatthour-to-investment ratio is equal to or greater than 25 but less than 35; or

(b) the consumers-per-mile ratio is equal to or greater than 5 but less than 7.

(2) Five percent, for any purchaser for whom:

(a) the kilowatthour-to-investment ratio is equal to or greater than 15 but less than 25; or

(b) the consumers-per-mile ratio is equal to or greater than 3 but less than 5.

(3) Seven percent, for any purchaser for whom:

(a) the kilowatthour-to-investment ratio is less than 15; or

(b) the consumers-per-mile ratio is less than 3.

4. Irrigation Discount

a. Basic Irrigation Discount Principles

A discount of 4.6 mills per kilowatthour shall be applied to the charges for qualifying irrigation energy purchased under the Priority Firm Power and New Resource Firm Power rate schedules, during the billing months of April through October. This discount shall be applied subsequent to calculation of the Low Density Discount, if applicable. Any energy on which the irrigation discount is claimed shall be metered separately by the Purchaser, and used exclusively for agricultural irrigation or drainage pumping.

b. Qualifying Energy Purchases

The qualifying irrigation energy shall be determined as follows:

(1) All irrigation energy must be used exclusively for the purpose of irrigation and drainage pumping on agricultural land and be measured at the end-use irrigation customer's meter. The discount shall apply to the measured energy sales at the end-use.

(2) Energy subject to the discount must be purchased during the billing months of April through October.

(3) Purchasers of exchange energy under the Residential Purchase and Sale Agreement (RPSA) are eligible for the irrigation discount for the portion of their irrigation sales qualifying for the exchange under the RPSA contracts.

(4) General requirements customers are eligible for an irrigation discount for a portion of their irrigation sales equal to the share of their total sales served by BPA firm purchases (i.e., total irrigation and drainage pumping sales multiplied by BPA billing energy for Priority Firm or New Resources firm purchases divided by the total firm utility system requirements for the billing month).

c. Initial Reporting Requirements

Requests for the Irrigation Discount must include the following information:

(1) To receive an irrigation discount, a purchaser must file a request for the discount with its local BPA Area or District office by April 1 each year.

(2) In the request, the purchaser must certify that the irrigation energy is sold exclusively for use in irrigation and drainage pumping on agricultural land and that the discount is passed, in its entirety, to the irrigation consumer, regardless of whether the utility has raised its rates. BPA retains the right to verify, in a manner satisfactory to the Administrator, that the discounted energy is used for the sole benefit of the purchaser's irrigation load.

d. Annual Reporting Requirements

Purchasers shall submit an annual irrigation report to their local BPA Area or District office in order to receive the irrigation discount. Purchasers are required to report information related to monthly irrigation energy sales. If a utility does not read its irrigation meters monthly, the utility must estimate its monthly irrigation sales. These estimates shall be reviewed by BPA area and/or district offices. Purchasers must read their meters within 3 working days of the beginning and ending of the irrigation discount period (April-October). In order to qualify for the discount, the purchaser must submit all data to BPA by December 31 of the calendar year in which the sales occurred. Irrigation reports to BPA shall include the following monthly information for the reporting period:

(1) utility name and period for which the report is being made;

(2) total irrigation sales and total qualifying irrigation energy sales (in kilowatthours) by month;

(3) total qualifying irrigation sales (in kilowatthours) by month under 400 horsepower, for exchanging utilities;

(4) total utility firm system requirements for other than full requirement customers by month (in kilowatthours);

(5) total energy purchased from BPA under the Priority Firm or New Resource rate by month in kilowatthours ; and

(6) the Purchaser shall list each irrigation and drainage account number in its annual report and whether each irrigation consumer is billed monthly, bimonthly, or seasonally. If the Purchaser is an exchanging utility, the Purchaser shall also identify the size (in horsepower) of the connected load for each active account. A utility may submit monthly reports, if it chooses. In that case, the active list of accounts should be included in the last monthly report submitted.

5. Cost Recovery Adjustment Clause

a. Applicable Rate Schedules

The Cost Recovery Adjustment Clause (CRAC) applies to the Priority Firm Power (Exchange and Preference) (PF-89), Industrial Firm Power (IP-89), Variable Industrial Power (VI-87), Firm Capacity (CF-89), and New Resource Firm Power (NR-89) rate schedules. A percentage adjustment, labeled as CRAC%, is calculated for specific periods and applied to these rates by various formulas.

b. Evaluation and Adjustment Periods

There are two evaluation and adjustment periods for the Cost Recovery Adjustment Clause.

(1) Period 1

Period 1 is comprised of an evaluation period covering FY 1989 (October 1, 1988, through September 30, 1989) and an adjustment period of January 1, 1990, through September 30, 1990.

After September 30, 1989, BPA shall evaluate its preliminary, unaudited financial position by measuring its FY 1989 net revenues (BPA's total FY 1989 revenues less FY 1989 expenses).

Any resulting rate adjustment shall be at the Administrator's discretion, shall be upward only, and shall not be greater than 10.0 percent.

If the net revenues are less than zero for the evaluation period (FY 1989) as specified herein, BPA may adjust the applicable rates (PF-89, IP-89, VI-87, CF-89, and NR-89) upward over an adjustment period beginning January 1, 1990, and ending September 30, 1990.

(2) Period 2

Period 2 is comprised of an evaluation period covering FY 1990 and an adjustment period of January 1, 1991, through September 30, 1991.

Any resulting rate adjustment shall be at the Administrator's discretion, shall be upward only, and shall not be greater than 10.0 percent.

After September 30, 1990, BPA shall evaluate its preliminary, unaudited financial position by measuring its FY 1990 net revenues (BPA's total FY 1990 revenues less FY 1990 expenses). The amount of any CRAC adjustment resulting from Period 1 evaluation shall be subtracted from FY 1990 revenues to obtain the adjusted FY 1990 revenues. The adjusted FY 1990 revenues less FY 1990 expenses equals the adjusted FY 1990 net revenues. If adjusted FY 1990 net revenues are less than zero for Period 2, BPA may adjust the applicable rates (PF-89, IP-89, VI-87, CF-89, and NR-89) upward over an adjustment period beginning January 1, 1991, and ending September 30, 1991.

c. Formulas for the Cost Recovery Adjustment Clause

(1) Adjustment Calculation

BPA shall determine the net revenue for each evaluation period using the following formulas:

(a) Period 1:

NR1 = revenues - expenses

where:

revenues = total operating revenues (in millions of dollars) from the FCRPS Statements of Revenues and Expenses;

expenses = sum of total operating expenses, net interest expense, and any litigation settlement expenses or other extraordinary expenses shown separately on the FCRPS Statements of Revenues and Expenses (in millions of dollars);

NR1 = FY 1989 net revenues (in millions of dollars).

If NR1 is zero or greater, then there will be no rate adjustment; and

CR1 = zero

If NR1 is less than zero:

CR1 = absolute value of NR1, for Period 1.

The following formulas apply for the calculation of the percent that the Cost Recovery Adjustment Clause could increase the applicable rates during January 1, 1990, through September 30, 1990:

(i) If CR1 is greater than $29.7 million, then the CRAC% equals the lesser of:

(A) (CR1+12.015)/13.899; or

(B) 10.0 percent.

(ii) If CR1 is less than or equal to $29.7 million, then, for PF, CF, and NR rate schedules (IP and VI are not adjusted):

CRAC% = CR1/9.902

(b) Period 2:

NR2 = (revenues-ACR1) - expenses

where:

NR2 = Adjusted FY 1990 net revenues (in millions of dollars); and

ACR1 = The lesser of CR1 or $127.0 million; or equals zero if rates were not adjusted, at the discretion of the Administrator, in Period 1.

If NR2 is zero or greater, then there will be no rate adjustment.

If NR2 is less than zero, then:

CR2 = absolute value of NR2 for Period 2.

The following formulas apply for the calculation of the percent that the Cost Recovery Adjustment Clause could increase the applicable rates during January 1, 1991, through September 30, 1991:

(i) If CR2 is greater than \$33.1 million, then the CRAC% equals the lesser of:

(A) (CR2+12.083)/15.056; or

(B) 10.0 percent.

(ii) If CR2 is less than or equal to \$33.1 million, then, for PF, CF, and NR rate schedules (IP and VI are not adjusted):

CRAC% = CR2/11.014

d. <u>Application to Irrigation Discount</u>

In addition to the direct application of the cost recovery adjustment percentage (CRAC%) to the irrigation discount, an additional adjustment shall be made so that irrigation loads are not disproportionately affected by a 9-month adjustment period as compared to a 12-month adjustment period. The direct and additional adjustments are reflected in the following formula:

Adjusted Irrigation Discount (in mills per kilowatthour)

$$= 4.6 * (1 + \frac{CRAC\%}{100}) + (0.046 * CRAC\%)$$

where:

4.6 = Irrigation discount applicable to PF-89 and NR-89, in mills per kilowatthour; and

0.046 = adjustment to account for the disproportionate impact of CRAC on irrigation loads, in mills per kilowatthour per percentage CRAC adjustment.

e. <u>Cost Recovery Adjustment Clause Implementation Process</u>

(1) Within 30 days after the end of FY 1989 and within 30 days after the end of FY 1990, BPA shall make an initial calculation to identify the preliminary, unaudited net revenues.

(2) On or about November 1 of each of the years 1989 and 1990, BPA shall notify interested persons and the purchasers under each applicable rate schedule of BPA's initial findings concerning the net revenues for the evaluation period.

(a) If no adjustment is required, or if the Administrator waives implementation of an adjustment, BPA shall state in the notice the basis for its decision, and no further process will be required.

(b) If BPA determines that an adjustment to applicable rates is required, BPA shall state in the notice the amount of the adjustment, the calculation of the adjustment, and the resulting level of the adjustment to each applicable rate schedule. The notice shall also contain the data and assumptions prepared and relied upon by BPA, with references to additional documentation, if any, prepared and relied upon by BPA. Such documentation, if nonproprietary and/or nonprivileged, shall be available upon request unless unduly burdensome. The notice shall also contain the tentative schedule for the remainder of the implementation process.

(3) On or about November 6, 1989, and November 5, 1990, BPA shall conduct a public meeting in which interested persons and purchasers under each applicable rate schedule may seek off-the-record clarification, calculation, and application of the adjustment amount to specific rate schedules. For the purpose of further mailings, a list of the names and addresses of interested persons and purchasers (hereafter referred to as "mailing list") shall be compiled at this meeting.

(4) On or about November 10, 1989, and November 9, 1990, purchasers under each applicable rate schedule may submit information requests to BPA regarding the adjustment. The requests shall also be mailed to all persons on the mailing list. BPA shall respond to the requests within 2 working days of their receipt, or as soon as practicable if 2 days is insufficient time within which to respond.

(5) On or about November 17, 1989, and November 16, 1990, interested persons and purchasers under each applicable rate schedule may submit written comments to BPA regarding the adjustment. The comments shall also be mailed to all persons on the mailing list.

(6) On or about December 1, 1989, and November 30, 1990, commenters may respond to any comments.

(7) On or about December 1, 1989, and November 30, 1990, BPA may release, if available, revised preliminary unaudited net revenues and any resulting revised adjustment to applicable rate schedules.

(8) On or about December 15, 1989, and December 14, 1990, BPA shall conduct an on-the-record public comment forum in which interested persons and purchasers under each applicable rate schedule may present oral comments to BPA.

(9) On or about December 20, 1989, and December 19, 1990, BPA shall notify interested persons and purchasers under each applicable rate schedule of the audited net revenue balance, the amount of the adjustment, the calculation of the adjustment, and the resulting level of the adjustment to each applicable rate schedule. The notice shall also contain the data and assumptions prepared and relied upon by BPA, with references to additional documentation, if any, prepared and relied upon by BPA.

(10) If there is a rate adjustment due the CRAC following the FY 1989 evaluation period, it shall be in effect from January 1, 1990, through September 30, 1990.

If there is a rate adjustment due to the CRAC following the FY 1990 evaluation period, it shall be in effect from January 1, 1991, through September 30, 1991.

6. Coincidental Billing

Purchasers of Priority Firm Power and New Resource Firm Power shall be billed on a noncoincidental demand basis for power purchased at each point of delivery under the applicable rate schedule(s) unless the power sales contract specifically provides for coincidental demand billing among particular points of delivery. For the purpose of these rate schedules and GRSPs, the purchaser's noncoincidental demand is the sum of the highest hourly peak demands during the billing month for each of the purchaser's points of delivery. The purchaser's coincidental demand is the highest demand for the billing month calculated by summing, for each hour of every day, the purchaser's demands for power purchased under the applicable rate schedule at all coincidentally billed points of delivery. See the Special Provisions Exhibits of the Power Sales Contract, GCP, E, 17.

7. Conservation Surcharge

The Conservation Surcharge shall be applied monthly and shall equal 10 percent of the customer's total monthly charge for all power purchased under each rate schedule subject to the surcharge. The PF, CF, and NR rate schedules are subject to the Conservation Surcharge. If only a portion of the customer's service area is subject to the surcharge, then the amount of the surcharge shall equal 10 percent of the total charge for all power purchases multiplied by: (a) the portion of the customer's total retail load that is subject to the surcharge, divided by (b) the customer's total retail load.

D. Billing-Related Definitions

1. Peak Period

The Peak Period includes the hours from 7 a.m. through 10 p.m. on any day Monday through Saturday inclusive. There are no exceptions to this definition; that is, it does not matter whether the day is a normal working day or a holiday. Any charges based on Peak Period hours shall be computed starting with the 8 a.m. meter reading since this reading applies to the 7 o'clock hour (7 a.m. to 8 a.m.). The 10 p.m. meter reading (for the 9 p.m. to 10 p.m. period) is the last meter reading of the day applicable to the Peak Period.

2. Offpeak Period

The Offpeak Period includes all hours which do not occur during the Peak Period. Thus, the Offpeak Period consists of the hours from 10 p.m. to 7 a.m., Monday through Saturday and all hours on Sunday. This definition does not apply to the Special Industrial Offpeak Rate.

SECTION IV. OTHER DEFINITIONS

A. Computed Requirements Purchasers

1. Designation as a Computed Requirements Purchaser

A purchaser shall be designated as a computed requirements purchaser if it is so designated pursuant to the provisions of its power sales contract.

When a purchaser operates two or more separate systems, only those systems designated by BPA will be covered by this section.

2. Purpose of the Computed Requirements Designation

Use of the computed requirements designation is intended to assure that each purchaser who purchases power from BPA to supplement its own firm resources will purchase amounts of firm capacity and firm energy substantially equal to that which the purchaser would otherwise have to provide on the basis of normal and prudent operations.

The amount of capacity and energy required for normal and prudent operations shall be determined pursuant to the purchaser's power sales contract.

B. Definitions Relating to Nonfirm Energy

Decremental Cost

Unless otherwise specified in a contractual arrangement, decremental cost as applied to Nonfirm Energy transactions shall be defined as:

1. All identifiable costs (expressed in mills per kilowatthour) associated with the use of a displaceable thermal resource or end-user load with alternate fuel source to serve a purchaser's load that the purchaser is able to avoid by purchasing power from BPA, rather than generating the power itself or using an alternate fuel source; or

2. All identifiable costs (expressed in mills per kilowatthour) to serve the load of a displaceable purchase of energy that the purchaser is able to avoid by choosing not to make the alternate energy purchase.

All identifiable costs as used in the above definition may be reduced to reflect costs of purchasing BPA energy such as transmission costs, losses, or loopflow constraints that are agreed to by BPA and the purchaser.

C. NF Rate Cap

1. Application of the NF Rate Cap

The NF Rate Cap defines the maximum nonfirm energy price for general application. At no time shall the total price for nonfirm energy, including any applicable service charges or rate adjustment, sold under any applicable rate schedule exceed the NF Rate Cap. The level of the NF Rate Cap is based on formula tied to BPA's system cost and California fuel costs. The NF Rate Cap applies to all sales of nonfirm energy under any applicable rate schedule for a 12-year period beginning October 1, 1987.

2. Monthly Notification of the NF rate Cap

Prior to the beginning of a calendar month BPA shall perform the calculations contained in section IV.C.3. of these GRSPs to determine the effective NF Rate Cap for that calendar month. BPA is obligated to provide advance notification of the NF Rate Cap level to purchasers of nonfirm energy. BPA may waive this requirement only if BPA does not intend to offer Nonfirm Energy at prices above BASC at any time during a month. The notification will be given at least 10 calendar days prior to the first day of any calendar month in which the NF Rate Cap applies. BPA shall also maintain, on file for public review, a record of the NF rate Cap by month throughout the period the cap is in effect.

3. NF Rate Cap Formula

The NF Rate Cap shall be equal to the greater of the following:

a. BASC; or

b. BASC + .30(DEC - BASC)

Where:

BASC = BPA's average system cost, determined by dividing BPA's total system costs by BPA's total system sales. For this rate period BASC has been determined to be 23.2 mills per kilowatthour.

DEC = The Decremental Fuel Cost as determined in accordance with section IV.C.5. of these GRSPs.

4. Determination of BPA's average system cost

For purposes of determining BPA's average system cost (BASC), the following definition shall apply:

a. BPA's total system costs shall be the sum of all BPA's costs forecasted in each general rate case for the applicable rate period, including total transmission costs, Federal base system costs, new resource costs, exchange resource costs, and other costs not specifically allocated to a rate pool, such as section 7(g) costs.

b. BPA's total annual system sales shall be the sum of all BPA's system firm and nonfirm sales forecasted each general rate case for the applicable test period.

BASC shall be redetermined in each subsequent general rate case according to the above formula and will be in effect for the entire rate period over which the rates are in effect.

5. Determination of Decremental Fuel Cost

The Decremental Fuel Cost shall be determined monthly by BPA. For purposes of calculating the NF Rate Cap, a weighted average of gas and petroleum prices for California will be used for approximating decremental fuel costs. The monthly decremental fuel cost shall be:

a. the sum of:

(1) the average California price for gas determined by multiplying the monthly gas use (WGU) developed pursuant to section IV.C.8.a. times the monthly California gas price (MGP) determined pursuant to section IV.C.6 rounded to the nearest tenth of a mill; and

(2) the average California price for petroleum determined by multiplying the monthly petroleum use (WOU) developed pursuant to section IV.C.8.b times the monthly California petroleum price (MOP) determined pursuant to section IV.C.7. rounded to the nearest tenth of a mill.

b. divided by the sum of the monthly gas use (WGU) and monthly petroleum use (WOU) developed in section IV.C.8.a. and b. respectively rounded to the nearest tenth of a mill.

6. California Gas Price

The monthly gas price (MGP) for purposes of calculating the decremental cost component of the rate cap shall based on the following formula:

$$MGP = \frac{AGP * HGP}{10}$$

Where:

AGP = the average gas price for California electric utility plants expressed in cents per million Btu as reported in the most recent monthly issue of Electric Power Monthly (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy. Prices shall be rounded to the nearest one-tenth of a cent.

HGP = the historical relationship between gas prices in the effective month of the NF Rate Cap (month t) and the month in which the gas prices are reported in EPM (month r) using the following procedures:

a. summing all California gas prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California gas prices shall be divided by the number of years for which monthly gas prices were reported and rounded to the nearest one-tenth of a cent.

b. summing all California gas prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California gas prices shall be divided by the number of years for which monthly gas prices were reported and rounded to the nearest one-tenth of a cent.

c. dividing the average monthly California gas price in a. above, by the average monthly California gas price in b. above, and rounding to the nearest one-tenth, or three significant places.

10 = the factor for converting gas prices stated in cents per million Btu to mills per kWh. The factor assumes a heat rate of 10,000 Btu per kilowatthour.

7. <u>California Petroleum Price</u>

The monthly petroleum price (MOP) for purposes of calculating the decremental cost component of the rate cap shall based on the following formula:

$$MOP = \frac{AOP * HOP}{10}$$

Where:

AOP = the last available average oil price for California electric utility plants expressed in cents per million Btu reported in <u>Electric Power Monthly</u> (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy. Prices shall be rounded to the nearest one-tenth of a cent.

HOP = the historical relationship between petroleum prices in the effective month of the NF Rate Cap (month t) and the last month in which the petroleum prices are reported in EPM (month r) using the following procedures:

a. summing all California petroleum prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California petroleum prices shall be divided by the number of years for which monthly petroleum prices were reported and rounded to the nearest one-tenth of a cent.

b. summing all California petroleum prices, expressed in the nearest one-tenth of a cent per million Btu, reported in EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of the historical monthly California petroleum prices shall be divided by the number of years for which monthly petroleum prices were reported and rounded to the nearest one-tenth of a cent.

c. dividing the average monthly California petroleum price in a. above, by the average monthly California petroleum price in b. above, and rounding to the nearest one-tenth of a percent, or three significant places.

10 = the factor for converting petroleum prices stated in cents per million Btu to mills per kWh. The factor assumes a heat rate of 10,000 Btu per kilowatthour.

8. Weighting Factors

For purposes of determining California fuel prices for the month, gas and petroleum prices will be weighted based on California's historical use of these two alternative fuels.

a. Historical Gas Use in California

The following formula shall be used to determine the weighting factor for gas prices (WGU):

$$WGU = CGU * HGU$$

Where:

CGU = the monthly net gas-fired generation, expressed in gigawatthours, for California in the most recent monthly issue of Electric Power Monthly (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy.

HGU = the historical relationship between gas consumptions in the effective month of the NF Rate Cap (month t) and the month for which gas consumption is reported in EPM (month r) using the following procedures:

(1) summing the reported net-gas fired generation for California, expressed in gigawatthours, from EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which gas consumption was reported and rounded to the nearest gigawatthour.

(2) summing the reported net gas-fired generation for California, expressed in gigawatthours, from EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which gas consumption was reported and rounded to the nearest gigawatthour.

(3) dividing the average consumption of gas in California for the month t as determined in (1) above by the average consumption of gas for the month r as determined in (2) above and rounding to the nearest one-tenth, or three significant places.

b. Historical Petroleum Use in California

The following formula shall be used to determine the weighting factor for petroleum prices (WOU):

$$WOU = COU * HOU$$

Where:

COU = the monthly net petroleum-fired generation, expressed in gigawatthours, in California in the most recent monthly issue of Electric Power Monthly (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy.

HOU = the historical relationship between petroleum consumptions in the effective month of the NF Rate Cap (month t) and the month for which petroleum consumption is reported in EPM (month r) using the following procedures:

(1) summing the reported net-petroleum generation for California, expressed in gigawatthours, from EPM for month t for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which petroleum consumption was reported and rounded to the nearest gigawatthour.

(2) summing the reported net-petroleum generation for California, expressed in gigawatthours, from EPM for month r for the years beginning with calendar year 1982 up to and including the prior calendar year. The sum of California's historical monthly consumption shall be divided by the number of years for which petroleum consumption was reported and rounded to the nearest gigawatthour.

(3) dividing the average consumption of petroleum in California for the month t as determined in (1) above by the average consumption of petroleum for the month r as determined in (2) above and rounding to the nearest one-tenth, or three significant places.

D. Determination of BPA's Average System Cost.

For purposes of determining BPA's average system cost (BASC), the following definition shall apply:

1. BPA's total system costs shall be the sum of all BPA's costs forecasted in each general rate case for the applicable rate period, including total transmission costs, Federal base system costs, new resource costs, exchange resource costs, and other costs not specifically allocated to a rate pool, such as section 7(g) costs.

2. BPA's total annual system sales shall be the sum of all BPA's system firm and nonfirm sales forecasted in each general rate case for the applicable test period.

BASC shall be redetermined in each subsequent general rate case according to the above formula and will be in effect for the entire rate period over which the rates are in effect.

SECTION V. APPLICATION OF RATES UNDER SPECIAL CIRCUMSTANCES

A. Energy Supplied for Emergency Use

A purchaser taking Priority Firm or New Resource Firm Power shall pay in accordance with the Nonfirm Energy rate schedule, NF-89, and Emergency Capacity rate schedule, CE-89, for any electric energy or capacity which has been supplied:

1. for use during an emergency on the purchaser's system, or

2. following an emergency to replace energy secured from sources other than BPA during such emergency.

Mutual emergency assistance may, however, be provided and payment therefore settled under exchange agreements.

B. Construction, Test and Start-Up, and Station Service

Power for the purpose of construction, test and start-up, and station service shall be made available to eligible purchasers under the Priority Firm and New Resource Firm Power Rate Schedules. Such power must be used in the manner specified below:

1. Power sold for construction is to be used in the construction of the project.

2. Power sold for test and start-up may be used prior to commercial operation both to bring the project on line and to ensure that the project is working properly.

3. Power sold for station service may be purchased at any time following commercial operation of the project. Station service power may be used for project start-up, project shut-down, normal plant operations, and operations during a plant shut-down period.

C. Application of Rates During Initial Operation Period--Transitional Service

1. Eligibility for Transitional Service

For an initial operating period, as specified in the power sales contract, 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 to bill the purchaser in accordance with the provisions of this section. This section shall apply to both:

a. DSIs having new, additional or reactivated plant facilities, and

b. utility purchasers serving industrial purchasers with power purchased from BPA. BPA will provide transitional service to utilities for only those industrial loads for which the demand can be separately metered by the utility and recorded on a daily basis.

2. Calculation of the Daily Demand

If the purchaser requests billing on a Daily Demand basis pursuant to its power sales contract and if BPA agrees to such billing, the billing demand for the billing month shall be the average of the Daily Demands as adjusted for power factor.

Demand for each day shall be defined as 100 percent of the Measured Demand for the day (regardless of whether such Measured Demand occurs during the Peak Period or the Offpeak Period).

3. Billing for Transitional Service

Utilities receiving transitional service shall provide BPA with Daily Demand information for the industrial consumer for whom transitional service is provided. To compute the power bill for the point of delivery which includes the load being served with transitional service, BPA shall, at its discretion, either:

a. determine the demand for the pertinent point of delivery without the industrial load and then add the average daily demand for such industrial load; or

b. bill the entire point of delivery on a daily demand basis.

Daily demand billing shall not affect the level of any curtailment charge or energy charge assessed by BPA.

D. Changes in a DSI's BPA Operating Level

If a DSI requests a waiver regarding the notice requirements specified in the DSI's power sales contract for a voluntary change in its BPA Operating Level, and if BPA does not grant the waiver, or if the DSI fails to give notice of such a change and does not request a waiver, the DSI shall be billed as if no notice has been provided until such time as the number of days in the notice period have passed. If, however, BPA agrees to waive the notice requirement, the power bill shall reflect the requested changes as of the requested effective date specified in the notice or, at BPA's discretion, a date of BPA's choosing within the notice period.

E. Restriction of Deliveries

Deliveries of capacity or energy to any purchaser may be restricted when operation of the facilities used by BPA to serve such purchaser is:

1. suspended,

2. interrupted,

3. interfered with,

4. curtailed, or

5. restricted

by the occurrence of any condition described in the Uncontrollable Forces or Continuity of Service sections of the General Contract Provisions of the power sales contract.

SECTION VI. BILLING INFORMATION

A. Determination of Estimated Billing Data

If the amounts of capacity, energy, or the 60-minute integrated demands for energy purchased from BPA must be estimated from data other than metered or scheduled quantities, historical patterns, and pertinent weather data, 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, derived by any method, a determination binding on both parties shall be made in accordance with the arbitration provisions of the power sales contract.

B. Load Shift and Outage Reports

Load shift and outage reports must be submitted to BPA within 4 days of the corresponding load shift or outage. Reports may be made by telephone, mail, or other electronic processes where available. If customer reports are not received in a timely manner, BPA has the option to withhold load shift or outage credit.

C. Billing for New Large Single Loads

Any BPA customer whose total load includes one or more New Large Single Loads (NLSL) shall be billed for the NLSL(s) at the New Resource Firm Power Rate. The power requirements associated with the NLSL shall be established in a manner consistent with the provisions of this section.

The purchaser shall warrant to BPA that NLSLs are separately metered. The metering must include provisions for determining:

1. the NLSL demand during BPA's diurnal capacity billing periods,

2. the NLSL energy during BPA's energy billing periods, and

3. the NLSL reactive energy for the billing month.

The design for the metering equipment for the NLSL must be approved by BPA. Testing and inspections of such metering installations shall be as provided in the General Contract Provisions.

On a monthly basis, each purchaser of New Resource Firm Power shall report to BPA the quantity of power used by the NLSL during the purchaser's billing period. Data provided to BPA by the purchaser must be submitted to BPA within 2 normal working days of the date the purchaser reads the meters. BPA may elect to adjust the NLSL data for losses from the point of metering to the closest BPA point of delivery for the purchaser.

D. Determination of Measured Demand

1. For points of delivery with fully operational metering under the Revenue Metering System (RMS), demand shall be measured from 0000 hours on the first day of the billing period through 2400 hours on the last day of the billing period.

2. For points of delivery that do not have RMS metering, demand shall be measured from 0000 hours on the first complete (24 hour) day of the available metering data through 2400 hours on the last complete day of the available metering data. Billing demand will be determined from the period of available metering data that most closely matches the official billing period of the customer.

E. Determination of Measured Energy

1. For points of delivery with fully operational metering under RMS, energy shall be measured from 0000 hours on the first day of the billing period through 2400 hours on the last day of the billing period.

2. For points of delivery that do not have RMS metering, measured energy shall be the quantity of usage recorded on the meter between meter readings.

F. Billing Month

Meters normally will 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 than or more than the normal billing month, the monthly charges stated in the applicable rate schedule shall be adjusted appropriately.

The calendar month in which the purchaser's meter is scheduled to be read determines the billing month. (Thus, a bill associated with a meter scheduled to be read on April 10 would be an April bill.) The charges for the winter and summer periods identified in the rate schedules apply to the purchaser's billing months.

G. Payment of Bills

Bills for power shall be rendered monthly by BPA. Failure to receive a bill shall not release the purchaser from liability for payment. Bills for amounts due BPA of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

   Demand and energy billings for power purchased under each rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amount from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

   At its option, BPA 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 shall have the validity of and be subject to the same payment provisions as a final bill.

3. Due Date

   Bills shall be due by close of business on the 20th day after the date of the bill (due date). This requirement holds also for revised bills (see section 6 below). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the purchaser), the due date shall be the next following business day.

4. Late Payment

   Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

   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 due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the purchaser. However, such cancellation shall not affect the purchaser's liability for any charges accrued prior thereto under such contract.

5. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the purchaser is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

6. Revised Bills

As necessary, BPA may render a revised bill. A revised bill shall replace all previous bills issued by BPA that pertain to a specified customer for a specified billing period if the amount of the revised bill is less than the amount of the original bill. If the amount of the revision causes an additional amount to be due BPA beyond the original bill, a revised bill will be issued for the difference.

The date of the revised bill shall be determined as follows:

a. If the amount of the revised bill is equal to or less than the amount of the bill which it is replacing, the revised bill shall have the same date as the replaced bill.

b. If the amount of the revised bill is greater than the amount of the bill which it is replacing, the additional amount will be billed on a separate bill, and the date of the revised bill shall be its date of issue.

SECTION VII. VARIABLE INDUSTRIAL RATE PARAMETERS AND ADJUSTMENTS

A. Monthly Average Aluminum Price Determination

1. Calculation of the Monthly Billing Aluminum Price

The monthly billing aluminum price shall be determined by BPA for each billing month. For purposes of this rate schedule, the monthly billing aluminum price shall be based on the average price of aluminum in U.S. markets during the third calendar month prior to the billing month. The average price of aluminum in U.S. markets shall be defined as the average U.S. Transaction Price reported for the month by Metals Week, in cents per pound, rounded to the nearest tenth of a cent.

2. Notification of the Monthly Average Aluminum Price

BPA shall provide, 45 days prior to the billing month, written notification to purchasers under this rate schedule of the monthly billing aluminum price to be used for billing purposes. Upon written request supporting documentation shall be provided.

3. Changes in Aluminum Price Indicators

In the event that BPA determines that factors outside its control render the monthly average U.S. Transaction Price unusable as an approximation of U.S. market prices, BPA may develop and substitute another indicator for prices in U.S. markets. BPA shall notify interested parties of its intent to do so at least 120 days prior to the billing month in which the change would become effective. In this notification, BPA shall explain the reason for the substitution and specify the replacement indicator it intends to use. BPA also shall describe the methodology to determine the monthly billing aluminum price to be used for billing purposes under this rate schedule and shall provide the necessary data to be used in the calculation. Interested persons will have until close of business 3 weeks from the date of the notification to provide comments. Consideration of comments and more current information may cause the final methodology and the substitute aluminum price index to differ from those proposed. BPA shall notify all affected parties, and those parties that submitted comments, of its final determination 90 days prior to the billing month the new indicator shall be effective.

B. Annual Adjustments to the Lower and Upper Pivot Aluminum Prices

On July 1, 1987, and every July 1 thereafter, the Lower and Upper Pivot Aluminum Prices, as stated in section III.B of the rate schedule, shall be subject to change for billing purposes as herein described. The term "annual adjustment date" shall refer to July 1 of each year.

1. Implementation Procedures

Beginning in 1987 and every year thereafter, prior to April 1 of that year, BPA shall provide the purchasers under this rate schedule preliminary written estimates of proposed adjustments to the Lower and Upper Pivot Aluminum Prices. By the last working day of the month of April, BPA shall notify interested parties in writing of BPA's revised determinations concerning changes to the Lower and Upper Pivot Aluminum Prices. BPA shall describe how the adjustments were determined and provide the data used in the calculations. In addition to written notification, BPA may, but is not obligated to, hold a public comment forum to clarify its determinations and solicit comments. Interested persons may submit comments on the determinations to BPA and other parties. Comments will be accepted until close of business on the last working Friday in May. Consideration of comments and more current information may result in the final adjustment differing from the proposed adjustment. By June 30 of each year, BPA shall notify all VI purchasers, those parties that submitted comments, and parties that requested notification, of the final determination.

2. Annual Adjustment Procedures

a. Annual Adjustment of the Lower Pivot Aluminum Price

Beginning with the July 1, 1987, annual adjustment date, for each year that the Variable Industrial rate is in effect, the Lower Pivot Aluminum Price as stated in section III.B.1 of the rate schedule shall be adjusted on the July 1 annual adjustment date. The Lower Pivot Aluminum Price shall be revised by multiplying 59 cents per pound by the Cost Escalation Index described in section VII.B.3.b of these GRSPs and rounded to the nearest tenth of a cent. The revised Lower Pivot Aluminum Price shall replace the Lower Pivot Aluminum Price as stated in section III.B.1 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 billing months.

b. Annual Adjustment of the Upper Pivot Aluminum Price

For each year that the Variable Industrial rate is in effect, the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule shall be adjusted on the July 1 annual adjustment date.

(1) Annual adjustment for the period beginning July 1, 1987, and ending June 30, 1991

The Upper Pivot Aluminum Price shall be revised by multiplying 72 cents per pound by the Cost Escalation Index described in section VII.B.3.c of these GRSPs and rounded to the nearest tenth of a cent. The revised Upper Pivot Aluminum Price shall supersede the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 billing months.

(2) Annual Adjustment for the period beginning July 1, 1991, and ending June 30, 1993

The Upper Pivot Aluminum Price will be adjusted such that the Average Historical Aluminum Price described in section VII.B.4 of these GRSPs is the midpoint between the adjusted Upper Pivot Aluminum Price and the Average Historical Lower Pivot Aluminum Price described in section VII.B.5 below, except as limited to the greater of 65 cents per pound or the adjusted Lower Pivot Point for the year.

The Upper Pivot Aluminum Price shall equal the greater of:

(a) (2)(AAP) - ALP:

where

AAP = the Average Historical Aluminum Price described in section VII.B.4 of these GRSPs.

ALP = the Average Historical Lower Pivot Aluminum Price described in section VII.B.5 of these GRSPs.

(b) 65.0 cents per pound escalated to current dollars using the Cost Escalator for the Upper Pivot Aluminum Price described in section VII.B.3.c of these GRSPs.

or

(c) The adjusted Lower Pivot Aluminum Price for the year.

The revised Upper Pivot Aluminum Price shall supersede the Upper Pivot Aluminum Price as stated in section III.B.2 of the rate schedule and shall be used to determine the energy rate in the subsequent 12 months.

3. <u>Cost Escalators</u>

a. The cost indices described below shall be used in calculating the appropriate cost escalators. Each index shall be rounded to the nearest one-tenth of a percent, or three significant places.

(1) <u>Electricity Cost Index</u>

The average VI-86 rate in mills per kilowatthour based on the Plateau Energy Charge and the Discount for Quality of First Quartile Service in effect on the April 1 preceding the annual adjustment date and a load factor of 98.5 percent; divided by 22.8 mills per kilowatthour (the average VI-86 rate assuming the plateau energy charge and the Discount for Quality of First Quartile Service in 1986).

(2) <u>Labor Cost Index</u>

The annual average hourly earnings for the U.S. primary aluminum industry (SIC 3334) over the previous complete calendar year, from the Employment and Earnings, published by the U.S. Department of Labor, Bureau of Labor Statistics (BLS), divided by $14.20 per hour (the value of SIC 3334 earnings reported for 1985).

(3) Alumina Cost Index

The annual average of the monthly billing aluminum prices described in section VII.A of the GRSPs for the previous 1-year period beginning July 1 through June 30 divided by 50.8 cents per pound (the average U.S. Transaction price over the period April 1985 through March 1986).

(4) Other Costs Index

The annual average GNP Implicit Price Deflator for the previous complete calendar year, as published by the U.S. Department of Commerce, Bureau of Economic Analysis, divided by 1.115 (the value of the GNP Implicit Price Deflator for 1985 with 1982 = 1.000).

In the event the indices delineated above are discontinued or revised in a manner that BPA determines renders them unusable for calculating a consistent cost index, BPA will adjust or substitute another similar price index, following advance notification and opportunity for public comment as described in section VII.B.1 of these GRSPs.

b. The Cost Escalator for the Lower Pivot Aluminum Price shall be a weighted average of the four indices contained in section VII.B.3.a above. The following weights shall be assigned each index:

Electricity Cost Index	.30
Labor Cost Index	.20
Alumina Cost Index	.20
Other Costs Index	.30

c. The Cost Escalator for the Upper Pivot Aluminum Price shall be a weighted average of the Electricity Cost and Other Cost Escalators as stated in sections VII.B.3.a.(1) and VII.B.3.a.(4) above. The following weights shall be assigned each index:

Electricity Cost Index	.25
Other Costs Index	.75

4. Average Historical Aluminum Price

Prior to the July 1, 1991, annual adjustment date and every annual adjustment date thereafter, an average historical aluminum price shall be calculated for the period the Variable rate has been in effect. The average historical aluminum price shall be determined following the procedures set forth below:

a. Each monthly billing aluminum price determined pursuant to section VII.A of these GRSPs for the period August 1, 1986, through June 30 immediately preceding the annual adjustment date, shall be escalated to the current year dollars using the Price Deflator procedures described in section VII.B.6 below.

b. The sum of the escalated monthly billing aluminum prices shall be divided by the number of months in the period and rounded to the nearest tenth of a cent to obtain the Average Historical Aluminum Price.

5. Average Historical Lower Pivot Aluminum Price

Prior to the July 1, 1991, annual adjustment date and every annual adjustment date thereafter, the average of the Lower Pivot Aluminum Prices for the period the Variable Industrial rate has been in effect shall be calculated following the procedures set forth below:

a. The Lower Pivot Aluminum Price in each month for the period August 1, 1986, through June 30 of the calendar year preceding the annual adjustment date, shall be escalated to the current year's dollars using the Price Deflator procedures described in section VII.B.6 below.

b. The sum of the escalated monthly Lower Pivot Aluminum Prices shall be divided by the number of months in the period, and rounded to the nearest tenth of a cent to obtain an Average Historical Lower Pivot Aluminum Price.

6. Price Deflator Procedures

For purposes of converting nominal dollars to real dollars in the calculation of the Average Historical Aluminum Price and the Average Historical Lower Pivot Aluminum Price, the following Price Deflator procedures shall be used:

a. Monthly billing aluminum prices and Lower Pivot Aluminum Prices for any calendar months July through December shall be inflated by multiplying the price by the ratio of the GNP Implicit Price Deflator for the calendar year prior to the annual adjustment date divided by the Implicit Price Deflator for the calendar year in which the price occurred.

b. Monthly billing aluminum prices and Lower Pivot Aluminum Prices for any calendar months January through June shall be inflated by multiplying the price by the ratio of the Implicit Price Deflator for the calendar year prior to the annual adjustment date divided by the Implicit Price Deflator for the calendar year prior to the year in which the price occurred. Each price shall be rounded to the nearest tenth of a cent.

APPENDIX C

TRANSMISSION RATE SCHEDULES

and

GENERAL TRANSMISSION RATE

SCHEDULE PROVISIONS

TRANSMISSION RATE SCHEDULES
AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS

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SCHEDULE FPT-89.1

FORMULA POWER TRANSMISSION

SECTION I. AVAILABILITY

This schedule is identical to and supersedes schedule FPT-87.1 for all firm transmission agreements which provide that rates may be adjusted not more frequently than once a year. It is available for firm transmission of electric power and energy using the Main Grid and/or Secondary System of the FCRTS. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm availability of service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. Full-Year Service

The monthly charge per kilowatt of billing 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 component factors as specified in the Agreement:

a. Main Grid Distance Factor: The amount computed by multiplying the Main Grid Distance by $0.0250 per mile;

b. Main Grid Interconnection Terminal Factor: $0.20;

c. Main Grid Terminal Factor: $0.25;

d. Main Grid Miscellaneous Facilities Factor: $1.04;

2. Secondary System Charge

The Secondary System Charge shall be the sum of one or more of the following component factors as specified in the Agreement:

a. Secondary System Distance Factor: The amount determined by multiplying the Secondary System Distance by $0.1255 per mile;

b. Secondary System Transformation Factor: $1.95;

c. Secondary System Intermediate Terminal Factor: $0.72;

d. Secondary System Interconnection Terminal Factor: $0.36;

3. Intertie Charge

For use of the Southern Intertie facilities: $5.21.

B. Partial-Year Service

The monthly charge per kilowatt of billing demand shall be as specified in Section II.A for all months of the year except for agreements whose term is 5 years or less and which specify service for fewer than 12 months per year, the monthly charge shall be:

1. during months for which service is specified, the monthly charge defined in Section II.A, and

2. during other months, the monthly charge defined in Section II.A multiplied by 0.2.

SECTION III. BILLING FACTORS

Unless otherwise stated in the Agreement, the billing demand shall be the largest of:

A. the Transmission Demand;

B. the highest hourly Scheduled Demand for the month; or

C. the Ratchet Demand.

SCHEDULE FPT-89.3

FORMULA POWER TRANSMISSION

SECTION I. AVAILABILITY

This schedule is identical to and supersedes schedule FPT-87.3 for all firm transmission agreements which provide that rates may be adjusted not more frequently than once every 3 years. It is available for firm transmission of electric power and energy using the Main Grid and/or Secondary System of the FCRTS. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm availability of service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. <u>Full-Year Service</u>

The monthly charge per kilowatt of billing 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. <u>Main Grid Charge</u>

The Main Grid Charge shall be the sum of one or more of the following component factors as specified in the Agreement:

a. Main Grid Distance Factor: The amount computed by multiplying the Main Grid Distance by $0.0250 per mile;

b. Main Grid Interconnection Terminal Factor: $0.20;

c. Main Grid Terminal Factor: $0.25;

d. Main Grid Miscellaneous Facilities Factor: $1.04;

2. <u>Secondary System Charge</u>

The Secondary System Charge shall be the sum of one or more of the following component factors as specified in the Agreement:

a. Secondary System Distance Factor: The amount determined by multiplying the Secondary System Distance by $0.1255 per mile;

b. Secondary System Transformation Factor: $1.95;

c. Secondary System Intermediate Terminal Factor: $0.72;

d. Secondary System Interconnection Terminal Factor: $0.36;

3. Intertie Charge

For use of the Southern Intertie facilities: $5.21.

B. Partial-Year Service

The monthly charge per kilowatt of billing demand shall be as specified in Section II.A for all months of the year except for agreements whose term is 5 years or less and which specify service for fewer than 12 months per year, the charge shall be:

1. during months for which service is specified, the monthly charge defined in Section II.A, and

2. during other months, the monthly charge defined in Section II.A multiplied by 0.2.

SECTION III. BILLING FACTORS

Unless otherwise stated in the Agreement, the billing demand shall be the largest of:

A. the Transmission Demand;

B. the highest hourly Scheduled Demand for the month; or

C. the Ratchet Demand.

SCHEDULE IR-89

INTEGRATION OF RESOURCES

SECTION I. AVAILABILITY

This schedule is identical to and supersedes IR-87 and is available for firm transmission service for electric power and energy using the Main Grid and/or Secondary System of the FCRTS. The definitions of Main Grid and Secondary Systems are the same as for the FPT-89.1 and FPT-89.3 rate schedules and are contained in the General Transmission Rate Schedule Provisions. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The monthly charge shall be the sum of A and B where:

A. The Demand Charge shall be:

1. $0.2600 per kilowatt of billing demand; or

2. for Points of Integration (POI) specified in the Agreement as being short distance POI's, for which Main Grid and Secondary System facilities are used for a distance of less than 75 circuit miles, the following formula applies:

   [0.2 + (0.8/75 x transmission distance)] ($0.2600 per kilowatt of billing demand)

Where:

the billing demand for a short distance POI is the demand level specified in the Agreement for such POI, and the transmission distance is the circuit miles between the POI for a generating resource of the customer and a designated Point of Delivery (POD) serving the load of the customer. Short distance POI's are determined by BPA after considering factors in addition to transmission distance.

B. The Energy Charge shall be:

0.85 mills/kWh of billing energy.

SECTION III. BILLING FACTORS

To the extent that the Agreement provides for the customer to be billed for transmission in excess of the Transmission Demand or Total Transmission

Demand, as defined in the Agreement, at the nonfirm transmission rate (currently ET-89), such transmission service shall not contribute to either the Billing Demand or the Billing Energy for the IR rate provided that the customer requests such treatment and BPA approves in accordance with the prescribed provisions in the Agreement.

A. Billing Demand

The billing demand shall be the largest of:

1. the Transmission Demand, except under General Transmission Agreements where a Total Transmission Demand is defined;
2. the highest hourly Scheduled Demand for the month; or
3. the Ratchet Demand.

B. Billing Energy

The billing energy shall be the monthly sum of scheduled kilowatthours.

SCHEDULE IS-89

SOUTHERN INTERTIE TRANSMISSION

SECTION I. AVAILABILITY

This schedule is identical to and supersedes IS-87 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

A. <u>Nonfirm Rate</u>

The charge for nonfirm transmission of non-BPA power shall be 1.4 mills/kWh of billing energy. This charge applies for both north-to-south and south-to-north transactions.

B. <u>Firm Power Transmission Rate</u>

The charge for firm transmission service granted access by BPA shall be $0.360 per kW per month of billing demand and 0.69 mills/kWh of billing energy. Firm transmission will only be made available to customers under this rate schedule who have executed a contract with BPA specifying use of the Firm Power Transmission rate for either north-to-south or south-to-north transactions.

SECTION III. BILLING FACTORS

A. For services under Section II.A, the billing energy shall be the monthly sum of the scheduled kilowatthours, plus the monthly sum of kilowatthours allocated but not scheduled. The amount of allocated but not scheduled energy that is subject to billing may be reduced prorata by BPA due to forced Intertie outages, and other uncontrollable forces that may reduce Intertie capacity. The amount of allocated but not scheduled energy that is subject to billing also may be reduced upon mutual agreement between BPA and the customer.

B. For services under Section II.B, the billing demand shall be the Transmission Demand as defined in the Agreement. The billing energy shall be the monthly sum of scheduled kilowatthours, unless otherwise specified in the Agreement.

SCHEDULE IN-89

NORTHERN INTERTIE TRANSMISSION

SECTION I. AVAILABILITY

This schedule is identical to and supersedes IN-87 and is available for all transmission on the Northern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The charge for transmission of non-BPA power on the Northern Intertie shall be 1.05 mills/kWh.

SECTION III. BILLING FACTORS

<u>Billing Energy</u>

The billing energy shall be the monthly sum of the scheduled kilowatthours.

SCHEDULE IE-89

EASTERN INTERTIE TRANSMISSION

SECTION I. AVAILABILITY

This schedule is identical to and supersedes IE-87 and is available for all nonfirm transmission on the Eastern Intertie. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The charge for transmission of nonfirm energy on the Eastern Intertie shall be 2.08 mills/kWh.

SECTION III. BILLING FACTORS

Billing Energy

The billing energy shall be the monthly sum of the scheduled kilowatthours.

SCHEDULE ET-89

ENERGY TRANSMISSION

SECTION I. AVAILABILITY

This schedule is identical to and supersedes Schedule ET-87, unless otherwise specified in the Agreement, with respect to delivery using FCRTS facilities other than the Southern Intertie, Eastern Intertie, or the Northern Intertie, and is available for nonfirm transmission between points within the Pacific Northwest. BPA may interrupt service which is provided under this rate schedule. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The charge for such nonfirm transmission of non-Federal electric energy shall be 1.61 mills/kWh.

SECTION III. BILLING FACTORS

Billing Energy

The billing energy shall be the monthly sum of scheduled kilowatthours.

SCHEDULE MT-89

MARKET TRANSMISSION

SECTION I. AVAILABILITY

This schedule is identical to and supersedes MT-87 and is available for Transmission Service for transactions using FCRTS facilities pursuant to the Western Systems Power Pool (WSPP) Agreement. Service under this schedule is subject to BPA's General Transmission Rate Schedule Provisions.

SECTION II. RATE

The charge shall be determined in advance by BPA. The charge shall not exceed 33 percent of the difference between the highest Decremental Cost of generation of the WSPP and the lowest Decremental Cost of generation of the WSPP as determined by the WSPP Operating Committee during the year prior to the effective date of the WSPP Agreement. The Operating Committee may determine that a subsequent redetermination is necessary based upon the immediately preceding year's experience. However, the transmission charge shall not be less than 1 mill per kilowatthour.

SECTION III. BILLING FACTORS

The billing factors shall be specified in advance by BPA, as to representing the Transmission Service use or reservation.

SCHEUDLE UFT-83

USE-OF-FACILITIES TRANSMISSION

SECTION I. AVAILABILITY

This schedule supersedes UFT-1, and UFT-2, unless otherwise provided in the Agreement, and is available for firm transmission over specified FCRTS facilities.

SECTION II. RATE

The monthly charge per kilowatt of Transmission Demand specified in the Agreement shall be one-twelfth of the annual cost of capacity of the specified facilities divided by the sum of Transmission Demands (in kilowatts) using such facilities. Such annual cost shall be determined in accordance with Section III.

SECTION III. 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 which are used to transmit electric power and energy:

   1. The annual cost of the specified FCRTS facilities, as determined from the capital cost of such facilities and annual cost ratios developed from the FCRTS financial statement, including interest and amortization, operation and maintenance, administrative and general, and general plant costs.

   2. The yearly noncoincident peak demands of all users of such facilities or other reasonable measurement of the facilities' peak use.

B. The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the annual cost of the FCRTS facilities used divided by the sum of Transmission Demands. The annual cost per kilowatt of Transmission Demand for a facility constructed or otherwise acquired by BPA shall be determined in accordance with the following formula:

$$\frac{A}{D}$$

Where:

A = The annual cost of such facility as determined in accordance with A.1. above.

D = The sum of the yearly noncoincident demands on the facility as determined in accordance with A.2. above.

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 IV. DETERMINATION OF BILLING DEMAND

Unless otherwise stated in the Agreement, the factor to be used in determining the kilowatts of billing demand shall be the largest of:

A. the Transmission Demand in kilowatts specified in the Agreement;

B. the highest hourly Measured or Scheduled Demand for the month, the Measured Demand being adjusted for power factor; or

C. the Ratchet Demand.

SCHEDULE TGT-1

TOWNSEND-GARRISON TRANSMISSION

SECTION I. AVAILABILITY

This schedule shall apply to all agreements which provide for the firm transmission of electric power and energy over transmission facilities of BPA's section of the Montana [Eastern] Intertie.

SECTION II. RATE

The monthly charge shall be one-twelfth of the sum of the annual charges listed below, as applicable and as specified in the agreements for firm transmission. The Townsend-Garrison 500-kV lines and associated terminal, line compensation, and communication facilities are a separately identified portion of the Federal Transmission System. Annual revenues plus credits for Government use should equal annual costs of the facilities, but in any given year there may be either a surplus or a deficit. Such surpluses or deficits for any year shall be accounted for in the computation of annual costs for succeeding years. Revenue requirements for firm transmission use will be decreased by any revenues received from nonfirm use and credits for all Government use. The general methodology for determining the firm rate is to divide the revenue requirement by the total firm capacity requirements. Therefore, the higher the total capacity requirements, the lower will be the unit rate.

If the Government provides firm transmission service in its section of the Montana [Eastern] Intertie in exchange for firm transmission service in a customer's section of the Montana Intertie, the payment by the Government for such transmission services provided by such customer will be made in the form of a credit in the calculation of the Intertie Charge for such customer. During an estimated 1- to 3-year period following the commercial operation of the third generating unit at the Colstrip Thermal Generating Plant at Colstrip, Montana, the capability of the Federal Transmission System west of Garrison Substation may be different from the long-term situation. It may not be possible to complete the extension of the 500-kV portion of the Federal Transmission System to Garrison by such commercial operation date. In such event, the 500/230 kV transformer will be an essential extension of the Townsend-Garrison Intertie facilities, and the annual costs of such transformer will be included in the calculation of the Intertie Charge.

However, starting one month after extension to Garrison of the 500-kV portion of the Federal Transmission System, the annual costs of such transformer will no longer be included in the calculation of the Intertie Charge.

A. Nonfirm Transmission Charge:

This charge will be filed as a separate Rate Schedule and revenues received thereunder will reduce the amount of revenue to be collected under the Intertie Charge below.

B. Intertie Charge for Firm Transmission Service:

$$\text{Intertie Charge} = [(\text{TAC}/12\text{-NFR}) \times \frac{(\text{CR-EC})}{\text{TCR}}]$$

SECTION III. DEFINITIONS

A. TAC = Total Annual Costs of facilities associated with the Townsend-Garrison 500-kV Transmission line including terminals, and prior to extension of the 500-kV portion of the Federal Transmission System to Garrison, the 500/230 kV transformer at Garrison. Such annual costs are the total of (1) interest and amortization of associated Federal investment and the appropriate allocation of general plant costs; (2) operation and maintenance costs; (3) allowance for Bonneville's general administrative costs which are appropriately allocable to such facilities, and (4) payments made pursuant to section 7(m) of Public Law 96-501 with respect to these facilities. Total Annual Costs shall be adjusted to reflect reductions to unpaid total costs as a result of any amounts received, under agreements for firm transmission service over the Montana Intertie, by the Government on account of any reduction in Transmission Demand, termination or partial termination of any such agreement or otherwise to compensate BPA for the unamortized investment, annual cost, removal, salvage, or other cost related to such facilities.

B. NFR = Nonfirm Revenues, which are equal to (1) the product of the Nonfirm Transmission Charge described in II(A) above, and the total nonfirm energy transmitted over the Townsend-Garrison line segment under such charge for such month; plus (2) the product of the Non-Firm Transmission Charge and the total nonfirm energy transmitted in either direction by the Government over the Townsend-Garrison line segment for such month.

C. CR = Capacity Requirement of a customer on the Townsend-Garrison 500-kV transmission facilities as specified in its firm transmission agreement.

D. TCR = Total Capacity Requirement on the Townsend-Garrison 500-kV transmission facilities as calculated by adding (1) the sum of all Capacity Requirements (CR) specified in transmission agreements described in section I; and (2) the Government's firm capacity requirement. The Government's firm capacity requirement shall be no less than the total of the amounts, if any, specified in firm transmission agreements for use of the Montana Intertie.

E. EC = Exchange Credit for each customer which is the product of (1) the ratio of investment in the Townsend-Broadview 500-kV transmission line to the investment in the Townsend-Garrison 500-kV transmission line; and (2) the capacity which the Government obtains in the Townsend-Broadview 500-kV transmission line through exchange with such customer. If no exchange is in effect with a customer, the value of EC for such customer shall be zero.

GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS

SECTION I. ADOPTION OF REVISED TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS

A. Approval of Rates

These rate schedules and General Transmission Rate Schedule Provisions (GTRSP) shall become effective upon approval by the Federal Energy Regulatory Commission. BPA will request FERC approval effective October 1, 1989. BPA is requesting that all proposed Transmission Rate Schedules be effective for a period of 2 years, from October 1, 1989, through September 30, 1991, with the exception of the TGT-1 and UFT-83 Rate Schedules which would be effective from July 1, 1990, through September 30, 1991. Approval of the FPT-87.3 Rate Schedule (renamed the FPT-89.3 Rate Schedule on October 1, 1989) is requested for a period of 1 year, from October 1, 1990, through September 30, 1991.

B. General Provisions

These 1989 Transmission Rate Schedules and associated GTRSP are identical to and supersede BPA's 1987 Transmission Rate Schedules and GTRSP (which became effective October 1, 1987) but do not supersede prior rate schedules required by agreement to remain in force.

Transmission service provided shall be subject to the following Acts, as amended: the Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Federal Columbia River Transmission System Act, and the Pacific Northwest Electric Power Planning and Conservation Act.

The meaning of terms used in the transmission rate schedules shall be as defined in agreements or provisions which are attached to the Agreement or as in any of the above Acts.

C. Interpretation

If a provision in the executed Agreement is in conflict with a provision contained herein, the former shall prevail.

SECTION II. BILLING FACTOR DEFINITIONS AND BILLING ADJUSTMENTS

A. Billing Factors

1. Scheduled Demand

   The largest of hourly amounts wheeled which are scheduled by the customer during the time period specified in the rate schedules.

2. Metered Demand

   The Metered Demand in kilowatts shall be largest of the 60-minute clock-hour integrated demands measured by meters installed at each POD during each time period specified in the applicable rate schedule. Such measurements shall be made as specified in the Agreement. BPA, in determining the Metered Demand, will exclude any abnormal readings due to or resulting from (a) emergencies or breakdowns on, or maintenance of, the FCRTS; or (b) emergencies on the customer's facilities, provided that such facilities have been adequately maintained and prudently operated as determined by BPA. If more than one class of power is delivered to any POD, the portion of the metered quantities assigned to any class of power shall be as agreed to by the parties. The amount so assigned shall constitute the Metered Demand for such class of power.

3. Transmission Demand

   The demand as defined in the Agreement.

4. Total Transmission Demand

   The sum of the transmission demands as defined in the Agreement.

5. Ratchet Demand

   The maximum demand established during the previous 11 billing months. Exception: If a Transmission Demand or Total Transmission Demand has been decreased pursuant to the terms of the Agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

B. Billing Adjustments

Average Power Factor

The adjustment for average power factor, when specified in a transmission rate schedule or in the Agreement, shall be made in accordance with the average power factor section of the General Wheeling Provisions.

To maintain acceptable operating conditions on the Federal system, BPA may restrict deliveries of power at any time that the average leading power factor or average lagging power factor for all classes of power delivered to such point or to such system is below 85 percent.

SECTION III. OTHER DEFINITIONS

Definitions of the terms below shall be applied to these provisions and the Transmission Rate Schedules, unless otherwise defined in the Agreement.

A. Agreement

An agreement between BPA and a customer to which these rate schedules and provisions may be applied.

B. Decremental Cost

As used in the MT rate schedule, Decremental Cost is as defined in the WSPP Agreement.

C. Eastern Intertie

The segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment including related terminals at Garrison.

D. Electric Power

Electric peaking capacity (kW) and/or electric energy (kWh).

E. Federal Columbia River Transmission System (FCRTS)

The transmission facilities of the Federal Columbia River Power System (FCRPS), which include all transmission facilities owned by the Government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

F. Firm Transmission Service

Transmission service which BPA provides for any non-BPA power except for transmission service which is scheduled as nonfirm. If the firm service is provided pursuant to the Agreement, the terms of the Agreement may further define the service.

G. Integrated Network

The segment of the FCRTS for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest, excluding facilities not segmented to the network in the Wholesale Power Rate Development Study used in BPA's rate development.

H. Main Grid

As used in the FPT and IR rate schedules, that portion of the Integrated Network with facilities rated 230 kV and higher.

I. Main Grid Distance

As used in the FPT rate schedules, the distance in airline miles on the Main Grid between the POI and the POD, multiplied by 1.15.

J. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

K. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, switching, transformation, and other facilities of the Main Grid not included in other components.

L. Main Grid Terminal

As used in the FPT rate schedules, the Main Grid terminal facilities located at the sending and/or receiving end of a line exclusive of the Interconnection terminals.

M. Nonfirm Transmission Service

Interruptible transmission service which BPA may provide for non-BPA power.

N. Northern Intertie

The segment of the FCRTS for which the transmission facilities consist of two 500 kV lines between Custer substation and the United States-Canadian border, one 500 kV line between Custer and Monroe Substations, and two 230 kV lines from Boundary substation to the United States-Canadian border, and the associated substation facilities.

O. Point of Integration (POI)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is made available to BPA for wheeling.

P. Point of Delivery (POD)

Connection points between the FCRTS and non-BPA facilities where non-Federal power is delivered to a customer by BPA.

Q. Secondary System

As used in the FPT and IR rate schedules, that portion of the Integrated Network facilities with operating voltage of 115 kV or 69 kV.

R. Secondary System Distance

As used in the FPT rate schedules, the number of circuit miles of Secondary System transmission lines between the secondary POI or the Main Grid and the POD or the lower voltage FCRTS facilities which may be used on a use-of-facility basis.

S. Secondary System Interconnection Terminal

As used in the FPT rate schedules, the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

T. Secondary System Intermediate Terminal

As used in the FPT rate schedules, the first and final terminal facilities in the Secondary System transmission path exclusive of the Secondary System Interconnection terminals.

U. Secondary Transformation

As used in the FPT rate schedules, transformation from Main Grid to Secondary System facilities.

V. Southern Intertie

The segment of the FCRTS for which the major transmission facilities consist of two 500 kV AC lines from John Day Substation to the

Oregon-California border, a portion of the 500 kV AC line from Buckley Substation to Summer Lake Substation, and one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border, and associated substation facilities.

W. Transmission Service

As used in the MT rate schedule, Transmission Service is as defined in the WSPP Agreement.

SECTION IV. BILLING INFORMATION

A. Payment of Bills

Bills for transmission service shall be rendered monthly by BPA. Failure to receive a bill shall not release the customer from liability for payment. Bills for amounts due of $50,000 or more must be paid by direct wire transfer; customers who expect that their average monthly bill will not exceed $50,000 and who expect special difficulties in meeting this requirement may request, and BPA may approve, an exemption from this requirement. Bills for amounts due BPA under $50,000 may be paid by direct wire transfer or mailed to the Bonneville Power Administration, P.O. Box 6040, Portland, Oregon 97228-6040, or to another location as directed by BPA. The procedures to be followed in making direct wire transfers will be provided by the Office of Financial Management and updated as necessary.

1. Computation of Bills

The transmission billing determinant is the electric power quantified by the method specified in the Agreement or Transmission Rate Schedule. Scheduled power or metered power will be used.

The transmission customer shall provide necessary information to BPA for any computation required to determine the proper charges for use of the FCRTS, and shall cooperate with BPA in the exchange of additional information which may be reasonably useful for respective operations.

Demand and energy billings for transmission service under each applicable rate schedule shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents through 99 cents to the next higher dollar.

2. Estimated Bills

At its option, BPA may elect to render an estimated bill to be followed at a subsequent billing date by a final bill. The estimated bill shall have the validity of and be subject to the same payment provisions as a final bill.

3. Due Date

Bills shall be due by close of business on the 20th day after the date of the bill (due date). Should the 20th day be a Saturday, Sunday, or holiday (as celebrated by the customer), the due date shall be the next following business day.

4. Late Payment

Bills not paid in full on or before close of business on the due date shall be subject to a penalty charge of $25. In addition, an interest charge of one-twentieth percent (0.05 percent) shall be applied each day to the sum of the unpaid amount and the penalty charge. This interest charge shall be assessed on a daily basis until such time as the unpaid amount and penalty charge are paid in full.

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 due date. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date and after giving 30 days advance notice in writing, BPA may cancel the contract for service to the customer. However, such cancellation shall not affect the customer's liability for any charges accrued prior thereto under such agreement.

5. Disputed Billings

In the event of a disputed billing, full payment shall be rendered to BPA and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified above. BPA shall separately account for the disputed amount. If it is determined that the customer is entitled to the disputed amount, BPA shall refund the disputed amount with interest, as determined by BPA's Office of Financial Management.

BPA retains the right to verify, in a manner satisfactory to the Administrator, all data submitted to BPA for use in the calculation of BPA's rates and corresponding rate adjustments. BPA also retains the right to deny eligibility for any BPA rate or corresponding rate adjustment until all submitted data have been accepted by BPA as complete, accurate, and appropriate for the rate or adjustment under consideration.

6. Revised Bills

At its option, BPA may render a revised bill. A revised bill shall replace all previous bills issued by BPA that pertain to a specified customer for a specified billing period if the amount of the revised bill is less than the amount of the original bill. If the amount of the revision causes an additional amount to be due BPA beyond the original bill, a revised bill will be issued for the difference.

The date of the revised bill shall be determined as follows:

a. If the amount of the revised bill is equal to or less than the amount of the bill which it is replacing, the revised bill shall have the same date as the replaced bill.

b. If the amount of the revised bill is greater than the amount of the bill which it is replacing, the date of the revised bill shall be its date of issue.

DOE/BP-1241
June 1989
3C

Administrator's Record of Decision

1989 Final Rate Proposal