# Administrator's Record of Decision

## 1995 Final Rate Proposal

WP-95-A-01
July 1995

BPA
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2831 A
1995

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BONNEVILLE
POWER ADMINISTRATION

# 1995 WHOLESALE POWER AND TRANSMISSION RATE PROPOSAL

# ADMINISTRATOR'S RECORD OF DECISION ESTABLISHING RATES

BONNEVILLE POWER ADMINISTRATION

U.S. DEPARTMENT OF ENERGY
JULY 1995

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TABLE OF CONTENTS


| | | Page |
|---|---|---|
| 1.0 | **INTRODUCTION** | 1 |
| 1.1 | **Procedural History** | 1 |
| 1.1.1 | Preliminary Proposal | 1 |
| 1.1.2 | Emerging Competition | 1 |
| 1.1.3 | Settlement Negotiations and Agreement | 2 |
| 1.1.4 | BPA's Initial Proposal | 3 |
| 1.1.5 | Procedural History of This Rate Proceediing | 4 |
| 1.2 | **Legal Guidelines Governing Establishment of Rates** | 6 |
| 1.2.1 | Statutory Guidelines | 6 |
| 1.2.2 | Broad Ratemaking Discretion Vested in the Administrator | 8 |
| 1.3 | Confirmation and Approval of Rates | 8 |
| 1.3.1 | Firm Power Rates and Transmission Rates | 8 |
| 1.3.2 | Nonfirm Energy Rates | 9 |
| 2.0 | **SUBSTANTIVE COST RECOVERY ISSUES** | 11 |
| 2.1 | **Introduction** | 11 |
| 2.1.1 | Development of the Revenue Requirement | 11 |
| 2.1.2 | Development of the Revenue Requirement for the FY 1996 Rate Period | 11 |
| 2.1.2.1 | Evidence to Support the Administrator's Cost Cuts | 13 |
| 2.1.2.2 | Program and Spending Levels | 16 |
| 2.1.2.3 | Probability of Treasury Repayment | 20 |
| 2.1.2.4 | Section 4(h)(10)(C) Credits | 28 |
| 2.1.2.5 | Cost and Revenue Components | 33 |
| 3.0 | **RATE DESIGN** | 43 |
| 3.1 | **Irrigation Discount** | 43 |
| 3.2 | **Power Rates** | 45 |
| 3.2.1 | Irrigation Discount | 46 |
| 3.2.2 | Low Density Discount | 49 |
| 3.2.3 | The 7(b)(2) Rate Test | 50 |
| 3.3 | **Transmission Rates** | 50 |
| 3.3.1 | Southern Intertie Annual Cost Rate | 51 |
| 4.0 | **PROCEDURAL ISSUES** | 53 |
| 4.1 | **Section 7(i) Process** | 53 |
| 4.1.1 | Adequacy of Initial Proposal | 53 |
| 4.1.2 | Hearing Officer's Denial of Motion to Strike Errata | 58 |
| 4.1.3 | Hearing Officer's Rulings on Data Requests | 63 |
| 4.1.3.1 | Denial of Motion to Compel and Adequacy of Record | 63 |
| 4.1.3.2 | Granting of Motion Re: CBI Data | 67 |
| 4.1.3.3 | Compliane With Procedural Orders in the Rate Proceeding | 69 |
| 4.2 | **Settlement Agreement** | 70 |
| 4.2.1 | Administrator's Discretion to Determine Final Rates Based on the Record | 72 |
| 4.3 | **Waivers and SP Contracts** | 72 |
| 4.3.1 | Appropriateness of Rate Case Review of Contracts | 72 |

**4.4 Environmental Analysis** ..... 73
4.4.1 Introduction ..... 73
4.4.2 NEPA Analysis ..... 74

**5.0 COMMENTS OF PARTICIPANTS** ..... 79
5.1 Introduction ..... 79
5.2 Field Hearings and Initial Proposal Comment Period ..... 79
5.3 List of Participants ..... 84

**6.0 CONCLUSION** ..... 87

**APPENDICES**

A. 1995 Wholesale Power Rate Schedules and General Rate Schedule Provisions

B. 1995 Transmission Rate Schedules and General Transmission Rate Schedule Provisions

**BONNEVILLE POWER ADMINISTRATION**

**STUDIES, DOCUMENTATION, DIRECT TESTIMONY AND QUALIFICATION STATEMENTS FOR THE 1995 INITIAL RATE PROPOSAL**

## List of Study Documents - BPA

| Document No. | Study |
|---|---|
| WP-95-E-BPA-01-08 | Preliminary Documents Not Part of this Record. |
| WP-95-E-BPA-09 | Loads and Resources Study. |
| WP-95-E-BPA-09A | Loads and Resources Study- Documentation: Volume 1. |
| WP-95-E-BPA-09B | Loads and Resources Study- Documentation: Volume 2. |
| WP-95-E-BPA-10 | Revenue Requirement Study. |
| WP-95-E-BPA-10(E1) | Errata. |
| WP-95-E-BPA-10A | Revenue Requirement Study- Documentation: Volume 1. |
| WP-95-E-BPA-10A(E1) | Errata. |
| WP-95-E-BPA-10B | Revenue Requirement Study- Documentation: Volume 2. |
| WP-95-E-BPA-11 | Revenue Forecast Study. |
| WP-95-E-BPA-11(E1) | Errata. |
| WP-95-E-BPA-11A | Revenue Forecast Study Documentation. |
| WP-95-E-BPA-11A(E1) | Errata. |
| WP-95-E-BPA-12 | 7(b)(2) Rate Test Study. |
| WP-95-E-BPA-12A | 7(b)(2) Rate Test Study Documentation. |

## List of Qualification Statements of Witnesses - BPA

| BPA Exhibit No. | Witness | BPA Exhibit No. | Witness |
|---|---|---|---|
| WP-95-Q-BPA-01 | Moorman | WP-95-Q-BPA-12 | DeWolf |
| WP-95-Q-BPA-02 | Lee | WP-95-Q-BPA-13 | Woerner |
| WP-95-Q-BPA-03 | Stenberg | WP-95-Q-BPA-14 | Metcalf |
| WP-95-Q-BPA-04 | O'Sullivan | WP-95-Q-BPA-15 | Wedlund |
| WP-95-Q-BPA-05 | Pederson | WP-95-Q-BPA-16 | Hanson |
| WP-95-Q-BPA-06 | Misley | WP-95-Q-BPA-17 | Keep |
| WP-95-Q-BPA-07 | Davis | WP-95-Q-BPA-18 | Doubleday |
| WP-95-Q-BPA-08 | Lovell | WP-95-Q-BPA-19 | Mesa |
| WP-95-Q-BPA-09 | Homenick | WP-95-Q-BPA-20 | Parker |
| WP-95-Q-BPA-10 | Lefler | WP-95-Q-BPA-21 | Hagen |
| WP-95-Q-BPA-11 | Chow | | |

## List of Direct, Rebuttal, and Supplemental Testimony Documents - BPA

| Document No. | Testimony | Witnesses |
|---|---|---|
| WP-95-E-BPA-13 | Competitiveness/Settlement: Need for Transition | Moorman |
| WP-95-E-BPA-14 | Loads and Resources: Load Forecast | Lee, Stenberg, O'Sullivan, Pederson |
| WP-95-E-BPA-15 | Load and Resources: Resources | Misley, Davis |
| WP-95-E-BPA-16 | Revenue Requirement: Repayment, Risk and Segmentation. | DeWolf, Lovell, Homenick, Lefler, Chow |
| WP-95-E-BPA-16(E1) | Errata | DeWolf, Lovell, Homenick, Lefler, Chow |
| WP-95-E-BPA-17 | Revenue Forecast: Revenue Forecast | Metcalf, Woerner, Wedlund |
| WP-95-E-BPA-17(E1) | Errata | Metcalf, Woerner, Wedlund |
| WP-95-E-BPA-18 | 7(b)(2) Rate Test Study | Hanson, Keep, Doubleday |
| WP-95-E-BPA-19 | PNCA | Mesa |
| WP-95-E-BPA-19(E1) | Errata | Mesa |
| WP-95-E-BPA-19(E2) | Errata | Mesa |
| WP-95-E-BPA-19(E3) | Errata | Mesa |
| WP-95-E-BPA-20 | AC-95 | Hagen, Parker |
| WP-95-E-BPA-21 | Competitiveness/Settlement: Need for Transition | Moorman |
| WP-95-E-BPA-21(E1) | Errata | Moorman |
| WP-95-E-BPA-22 | Revenue Requirement: Repayment, Risk and Segmentation. | DeWolf, Lovell, Homenick, Lefler, Chow |
| WP-95-E-BPA-23 | Revenue Forecast: Revenue Forecast | Metcalf, Woerner, Wedlund |

## List of Prehearing Briefs - Parties

| Document No. | Party |
|---|---|
| WP-95-P-CB-01 | Columbia Basin Institute |
| WP-95-P-DS-01 | Direct Service Industries |
| WP-95-P-PP-01 | Public Power Council, Association of Public Agency Customers, Full Meal Deal Utilities, Northwest Irrigation Utilities, Pacific Northwest Generating Cooperatives, Public Generating Pool, & Requirements Customer Coalition |

## List of Qualification Statements - Parties

| Exhibit No. | Witness |
|---|---|
| WP-95-Q-CB-01 | Bell |
| WP-95-Q-DS-01 | Waddington |
| WP-95-Q-NI-01 | Saven |
| WP-95-Q-PP-01 | O'Meara |

## List of Direct and Rebuttal Testimony Documents - Parties

| Document No. | Testimony | Witness |
|---|---|---|
| WP-95-E-CB-01 | Irrigation Discount/Treasury Repayment Probability | Bell |
| WP-95-E-DS-01 | Settlement Agreement/Competitiveness | Waddington |
| WP-95-E-NI-01 | Irrigation Discount | Saven |
| WP-95-E-PP-01 | Settlement Agreement/Competitiveness | O'Meara |

## List of Parties Initial Briefs - Parties

| Document No. | Party |
|---|---|
| WP-95-B-CB-01 | Columbia Basin Institute |
| WP-95-B-NI-01 | Northwest Irrigation Utilities |
| WP-95-B-PP-01 | Public Power Council |

## List of Final Studies and Documents - BPA

| Document No. | Study |
|---|---|
| WP-95-E-BPA-01-08 | Not Used in this Proceeding |
| WP-95-FS-BPA-09 | Final Loads and Resources Study. |
| WP-95-FS-BPA-09A | Final Loads and Resources Study- Documentation: Vol. 1. |
| WP-95-FS-BPA-09B | Final Loads and Resources Study- Documentation: Vol. 2. |
| WP-95-FS-BPA-10 | Final Revenue Requirement Study. |
| WP-95-FS-BPA-10A | Final Revenue Requirement Study- Documentation: Vol. 1. |
| WP-95-FS-BPA-10B | Final Revenue Requirement Study- Documentation: Vol. 2. |
| WP-95-FS-BPA-11 | Final Revenue Forecast Study. |
| WP-95-FS-BPA-11A | Final Revenue Forecast Study Documentation. |
| WP-95-FS-BPA-12 | Final 7(b)(2) Rate Test Study. |
| WP-95-FS-BPA-12A | Final 7(b)(2) Rate Test Study Documentation. |

| | |
|---|---|
| WP-95-A-01 | Administrator's Record of Decision |

## LIST OF PARTIES AND CODES

| Party | Code |
|---|---|
| Association of Public Agency Customers[1] | PA |
| Austin Collins | AC |
| Bonneville Power Administration | BPA |
| British Columbia Power Exchange Corporation | BC |
| California Energy Commission | CE |
| Central Lincoln People's Utility District | CL |
| Chelan County PUD | CH |
| Citizens' Utility Board of Oregon | CU |
| Clark County Public Utility District No. 1 | CP |
| Columbia Basin Institute | CB |
| Columbia River Inter-Tribal Fish Commission | CR |
| Columbia River PUD | CD |
| Cowlitz County PUD | CO |
| Direct Service Industrial Customers [2] | DS |
| Douglas County PUD | DC |
| Edmonton Power Authority | EP |
| Electric Clearinghouse, Inc. | EC |
| Emerald People's Utility District | EM |
| Enron Power Marketing, Inc. | EN |
| Eugene Water & Electric Board | EW |
| Full Meal Deal Utilities[3] | FM |
| Grant County PUD | GR |
| Idaho Power Company | IP |
| Inland Power & Light Company | IN |
| Intalco Aluminum Corporation | IT |
| Klamath Energy | KE |
| Louis Dreyfus Electric Power Inc. | LD |
| Montana Power Company | MP |
| Northwest Conservation Act Coalition | NA |
| Northwest Irrigation Utilities[4] | NI |

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[1] Association of Public Agency Customers include: Boise Cascade Corporation, International Paper Company, James River Corporation, Longview Fibre Company, Occidental Chemical corporation, Simpson Paper Company, and The Boeing Company.

[2] Direct Service Industrrial Customers include: Aluminum Comapny of America, Atochem North America, Inc., Columbia Aluminum Corporation, Columbia Falls Aluminum Company, Georgai-Pacific Corporation, Intalco Aluminum Corporation, Kaiser Aluminum & Chemical Corporation, Northwest Aluminum Company, Reynolds Metal Company, and Vanalco, Inc.

[3] Full Meal Deal Utilities Group includes: Benton Rural ElectricAssociation, Big Bend Electric Cooperative, Inc., City of Cheney, City of Milton, City of Fircrest, Columbia Rural electric Association, Inc., Elmhurst Power & Light company, Ferry County P.U.D., Inland Power & Light company, Lincoln Electric Cooperation, Inc., Nespelem Valley electric Cooperative, Ohop Mutual Light Company, Okanogan county electric Cooperative, Orcas Power and Light Company, Parkland Light and Water Company, Skamania County P.U.D., Tanner Electric Cooperative, Wahkiakum County P.U.D.

[4] Northwest Irrigation Utilities include: Benton PUD, Benton Rural Electric Association, Big Bend Electric Cooperative, Inc., Central Electric Cooperative, Inc., Columbia Rural Electric Association, Inc., Columbia Basis Electric Cooperative, Inc., Columbia Power Cooperative Association, Coos-Curry electric Cooperative, Inc., Fall River Rural Electric Cooperative, Incorporated, Franklin county P.U.D., Harney Electric Cooperative, Inc.,Inland Power & Light, Klickitat County P.U.D., Lincoln Electric Cooperative, Inc., Lost River Electric Cooperative, Inc., Midstate Electric cooperativ, Inc., Olanogan County P.U.D., Raft River Electric Cooperative, Inc., Rural electric Company, Surprise Valley Electrification

| | |
|---|---|
| Northwest Power Planning Council | NP |
| Oregon Public Utility Commission | OP |
| PacifiCorp | PL |
| Pacific Northwest Generating Cooperative | PN |
| Pend Oreille County PUD | PO |
| Portland General Electric Company | GE |
| Public Generating Pool[5] | PG |
| Public Power Council | PP |
| Puget Sound Power & Light Company | PS |
| Renewable Northwest Project | RN |
| Requirements Customer Coalition[6] | RC |
| Salem Electric | SC |
| Seattle City Light | SL |
| Tacoma, (City of) Department of Public Utilities, Light Division | TU |
| Utility Reform Project | UP |
| Vanalco, Inc. | VN |
| Washington State Association of Community Action Programs' Energy Project (WAP Energy Project) | WE |
| Washington Utilities and Transportation Commission | WU |
| Washington Water Power Company | WP |
| Western Public Agencies Group[7] | WA |

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Corporation, Umatilla Electric Cooperative Association, Untiy Power & Light Company, Wasco Electric cooperative, Inc., Wells Rural Electric Company.

[5] The Public Generating Pool includes: Grant County PUD No. 2, Eugene Water & Electric Board, Seattle City Light, Tacoma City Light, Cowlitz County PUD, Chelan county PUD, Douglas County PUD, and Pend Oreille County PUD.

[6] Requirements Customer Coalition includes: Pacific Northwest Generating Cooperative, Norhtwest Irrigation Utilities, Idaho Cooperative Utilities Association, Non-Generating Public Utilities, and Western Montana Electric G & T Co-op.

[7] Western Public Agencies Group includes: Public Utility District No. 1 of Snohomish County, Elmhurst Mutual Power and Light Company, Ohop Mutual Light Company, City of Ellensburg, Public Utility District No. 2 of Pacific county, Public Utility District No. 1 of Clark County, Public Utility District No. 1 of Grays Harbor county, Peninsula Light Company, Lakeview Light & Power Company, Parkland Light and Water Company, Public Utility District No. 1 of Mason County, Public Utility District No. 3 of Mason County, City of Cheney, Alder Mutual Light Company, City of Milton, Town of Steilacoom, Town of Eatonville, City of Fircrest, and Public Utility District No. 1 of Kittitas County.

## COMMONLY USED ACRONYMS

| | |
|---|---|
| AC | Alternating Current or Southern Intertie Annual Costs (rate) |
| ACME | Accelerated California Market Estimator (computer program) |
| AER | Actual Energy Regulation |
| AF | Advance Funding |
| AFUDC | Allowance for Funds Used During Construction |
| aMW | Average Megawatt |
| AOP | Assured Operating Plan |
| APS | Ancillary Products and Services |
| ASC | Average System Cost |
| ASM | Aluminum Smelter Model |
| BASC | BPA's Average System Cost |
| BPA | Bonneville Power Administration |
| BTU | British Thermal Unit |
| CE | Emergency Capacity (rate) |
| cfs | Cubic feet per second |
| CO-OP | Co-operative Electric Utility |
| COB | California-Oregon Border |
| COE | United States Army Corps of Engineers |
| Con/Mod | Conservation Modernization Program |
| COSA | Cost of Service Analysis |
| CP | Coincidental Peak |
| CRC | Critical Rule Curves |
| CRFA | Columbia River flow augmentation |
| CSPE | Columbia Storage Power Exchange |
| CT | Combustion Turbine |
| CWIP | Construction Work In Progress |
| CY | Calendar Year (Jan - Dec) |
| DC | Direct Current |
| DOE | Department of Energy |
| DSIs | Direct Service Industrial Customers |
| DSM | Demand-Side Management |
| EA | Environmental Assessment |
| ECC | Energy Content Curve |
| EIS | Environmental Impact Statement |
| EPA '92 | Energy Policy Act of 1992 |
| ESA | Endangered Species Act |
| ET | Energy Transmission (rate) |
| ETCA | Exchange Transmission Credit Agreement |
| 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 |
| FLCC | Firm Load Carrying Capability |
| FPSs | Firm Power Products and Services |
| FPT | Formula Power Transmission (rate) |
| FRE | Firm Resource Exhibit |
| FSEA | Federal Secondary Energy Analysis |
| FY | Fiscal Year (Oct - Sep) |
| GCPs | General Contract Provisions |
| GPU | Generating Public Utilities |
| GRSPs | General Rate Schedule Provisions |
| GTA | General Transfer Agreement |
| GTRSPs | General Transmission Rate Schedule Provisions |
| IE | Eastern Intertie Transmission (rate) |
| IN | Northern Intertie Transmission (rate) |
| IOUs | Investor-Owned Utilities |
| IP | Industrial Firm Power (rate) |
| IR | Integration of Resources (rate) |
| IRE | Industrial Replacement Energy |
| IS | Southern Intertie Transmission (rate) |
| ISC | Investment Service Coverage |
| ksfd | thousand second foot days |
| KV | Kilovolt (1000 volts) |
| kW | Kilowatt (1000 watts) |
| kWh | Kilowatthour |
| LDD | Low Density Discount |
| LOLP | Loss of Load Probability |
| LTIAP | Long-Term Intertie Access Policy |
| Maf | Million Acre Feet |
| M/kWh | Mills per kilowatthour |
| MC | Marginal Cost |
| MCA | Marginal Cost Analysis |
| MCS | Model Conservation Standards |
| MW | Megawatt (1 million watts) |
| MW-miles | Megawatt-miles |
| MWh | Megawatthour |
| MT | Market Transmission (rate) |
| NEPA | National Environmental Policy Act |
| NF | Nonfirm Energy (rate) |
| NFRAP | Nonfirm Revenue Analysis Program (computer program) |
| NLSL | New Large Single Load |
| NMFS | National Marine Fisheries Service |
| NOB | Nevada-Oregon Border |
| NR | New Resource Firm Power (rate) |
| NRF | Northwest Regional Forecast |

| | |
|---|---|
| NSGPU | non- and small-generating public utilities |
| NSR | Named Set of FBS Resources |
| NT | Network Integration |
| NTSA | Non-Treaty Storage Agreement |
| NWPP | Northwest Power Pool |
| NWPPC | Northwest Power Planning Council |
| O&M | Operation and Maintenance |
| OMB | Office of Management and Budget |
| OY | Operating Year (August-July) |
| PA | Public Agency |
| PIP | Programs in Perspective |
| PF | Priority Firm Power (rate) |
| PMDAM | Power Market Decision Analysis Model (computer model) |
| PNCA | Pacific Northwest Coordination Agreement |
| PNUCC | Pacific Northwest Utilities Conference Committee |
| PNW | Pacific Northwest |
| POD | Point of Delivery |
| POI | Point of Integration or Interconnection |
| PS | Power Shortage (rate) |
| PSW | Pacific Southwest |
| PTP | Point-to-Point |
| PURPA | Public Utilities Regulatory Policies Act |
| PUD | Public or Peoples' Utility District |
| RAM | Rate Analysis Model (computer model) |
| REM | Regional Economic Model (computer model) |
| REVEST | Revenue Estimate (computer program) |
| ROD | Record of Decision |
| RP | Reserve Power (rate) |
| RPSA | Residential Purchase and Sale Agreement |
| RPSM | BPA's Resource Policy Screening Model |
| SDD | Short Distance Discount |
| SI | Special Industrial Power (rate) |
| SMEA | Shaped Monthly Energy Amounts |
| SP | Surplus Firm Power (rate) |
| SPM | Supply Pricing Model (computer program) |
| SPOM | Surplus Power-Open Market |
| SS | Share-the-Savings Energy (rate) |
| STREAM | Short-Term Risk Evaluation and Analysis Model |
| TGT | Townsend-Garrison Transmission (rate) |
| TRDS | Transmission Rate Design Study |
| UFT | Use of Facilities Transmission (rate) |
| USBR | United States Bureau of Reclamation |
| USFWS | United States Fish and Wildlife Service |
| VI | Variable Industrial Power (rate) |
| VOR | Value of Reserves |

| | |
|---|---|
| WNP | Washington Public Power Supply System (Nuclear) Project |
| WPPSS | Washington Public Power Supply System |
| WPRDS | Wholesale Power Rate Development Study |
| WSPP | Western Systems Power Pool |
| WSCC | Western Systems Coordinating Council |

# 1.0 INTRODUCTION

## 1.1 Procedural History

### 1.1.1 Preliminary Proposal

On December 28, 1994, Bonneville Power Administration (BPA) published a Notice of Intent to Revise Transmission Rates, 59 Fed. Reg. 66,946 (1994), and a Notice of Intent to Revise Wholesale Power Rates, 59 Fed. Reg. 66,947 (1994), in order to satisfy contractual provisions between BPA and its customers. On February 14, 1995, BPA published Federal Register Notices of Proposed Wholesale Power Rate Adjustment, 60 Fed. Reg. 8496 (1995), Proposed Transmission Rate Adjustment, 60 Fed. Reg. 8505 (1995), and Hearing and Opportunity for Public Comment Regarding Proposed Comparable Transmission Terms and Conditions, 60 Fed. Reg. 8511 (1995). The proposed adjustments were scheduled to become effective October 1, 1995, for the rate period of FYs 1996 and 1997. These proposals included notice of the date, time, and location at which a prehearing conference would be held. See 16 U.S.C. § 839e(i)(1).

In the February 14, 1995 notice, BPA stated that the proposal it was making at that time was preliminary. BPA concluded that the proposal, as developed at that point, would not reflect BPA's commitment to rate stability. Fast evolving changes to the West Coast power market led BPA to conclude that in order to improve its competitiveness and provide the products and services its customers demanded, BPA's formal rate case proposal, known as its "initial proposal," needed to include a stable 5-year rate for most, if not all, of its requirements service. The preliminary proposal did not include such a rate, and BPA concluded that it needed more time to devise such a proposal. Therefore, the purpose of the preliminary proposal, which contained information concerning rate design, product definition and pricing, revenue requirement, and other matters, was to provide customers and other parties valuable information that would enable them to better assess BPA's forthcoming initial proposal.

At that time, BPA was proposing to tier its rates so that new load placed on it would face the incremental costs of serving that new load. Tiered rates involved a very fundamental and significant redesign of BPA's power rates. In the next month, however, BPA determined that the adoption of tiered rates should be postponed because of their unwieldy complexity, changes in the marketplace, and changes in incremental costs relative to embedded cost.

### 1.1.2 Emerging Competition

Federal legislation designed to create access to transmission for all wholesalers on comparable terms, low gas prices, and surplus supplies of short-term capacity and energy on the West Coast have led to steadily falling electricity prices, giving BPA's customers cost-competitive choices regarding power supply that did not exist before. As a result, for

the first time in BPA's 57 year history, a significant number of alternatives to Federal power are available to BPA's customers at prices equal to or lower than BPA's priority and industrial firm power rates. BPA faces stiff competition from both new market entrants such as power marketers and brokers, as well as established and well-positioned West Coast utilities. Therefore, in the context of this emerging wholesale power market, purchasers of wholesale power realistically can demand and obtain competitive, stable, and predictable prices.

There is ample evidence that BPA's customers in fact are seeking new sources of supply to meet current and projected loads, and that some are taking existing load off BPA and placing it on new suppliers. See, testimony of Geoffrey B. Moorman, WP-95-E-BPA-13, p.10 et seq. At the same time, notwithstanding an aggressive cost-cutting program, BPA faces cost increases in some non-revenue producing areas, such as increasing costs of fish migration, that compel it to seek a rate surcharge for FY 1996.

### 1.1.3 Settlement Negotiations and Agreement

Faced with the necessity of pursuing a fundamentally different rate proposal, particularly one that needed to cover 5 years, BPA anticipated that the work necessary to develop such a proposal could take until July of 1995. This amount of time also foresaw the possibility of extended discussions with customers and third parties concerning the development of transmission rates, terms, and conditions that would satisfy FERC's evolving comparability standards. At the same time, numerous parties expressed a need for additional time to evaluate and respond to the new rate designs, and to evaluate the new rates in combination with the new power sales contracts BPA would be offering.

All of this was taking place against the backdrop of the fact that BPA's current rates were, with few exceptions, approved by FERC only through September 30, 1995. An extension of those rates would have to be pursued until BPA could develop the new rates. However, BPA was not willing to forgo a rate adjustment for another year, believing that without a temporary adjustment to its wholesale power and transmission rates for the period October 1, 1995, through September 30, 1996, its ability to satisfy its statutory cost recovery obligations would be seriously impaired.

As a consequence of these various factors, BPA executed a Settlement Agreement that had been signed by most customer parties to the 1995 rate proceeding. The Agreement, attached to the testimony of Geoffrey B. Moorman, WP-95-E-BPA-13, as Attachment B, states that: (a) BPA will propose to surcharge by 4 percent each component of BPA's current (1993) adjustable rates for 1 year, October 1, 1995, through September 30, 1996, and that BPA will propose to extend the VI-91 rate, which is scheduled to expire June 30, 1996, through September 30, 1996; (b) the Administrator's final decision must be supported by and made based on the rate case record; (c) signatories to the settlement will not oppose the surcharge proposal or the Administrator's adoption of rates based on the proposal; (d) no procedural or substantive precedent shall be created by the surcharge case; and (e) BPA will propose an 8-month rate case schedule for the establishment of

new 2- and 5-year rates for the period beginning October 1, 1996, and for the establishment of transmission service terms and conditions of general applicability.

Overall, the provisions of the Settlement Agreement provide BPA the opportunity to meet its short-term revenue needs, recognize the Administrator's responsibility to establish rates in compliance with statutory rate directives, afford BPA the time and opportunity to establish rates that will enable it to compete effectively, and meet the parties' demands for more time to evaluate and respond to BPA's newly proposed rate adjustments. The FY 1996 rate surcharge will provide BPA with a transition period during which it can develop, in better collaboration with its customers and interested third parties, new rates, new power and transmission products, and new contracts that better address both current market realities, and the longer term needs of BPA and its customers.

### 1.1.4 BPA's Initial Proposal

On May 1, 1995, BPA published, in accordance with the settlement agreements, a Notice Of Proposed Wholesale Power and Transmission Rates, Variable Industrial Power rate Extension (VI-95), and Pacific Northwest Coordination Agreement (PNCA) Rates, 60 Fed. Reg. 21,132 (1995). The full procedural history of this proceeding is described below.

BPA proposed that each component of current adjustable rates would be surcharged by 4 percent. Adjustable rates are those that are normally adjusted to reflect changes in BPA's costs and loads, and rates that are tied to such rates. For example, the Priority Firm Power (PF) demand and energy charges are adjustable to reflect changes in BPA's costs and loads, as is BASC (Bonneville's Average System Cost), a component of the Nonfirm Energy rate.

Other rate charges or discounts were proposed to be adjusted in two general instances. First, rate charges or discounts are adjusted to result in an overall effective rate increase of 4 percent. This includes the discount for power purchased to serve irrigation loads included in the current 1993 rates. Second, rate charges or discounts were proposed to be adjusted if they were based on the PF rate, by using the surcharged PF rate in the methodology adopted for the current 1993 rates. Penalties generally were not adjusted unless the penalty amount was tied to changes in other adjustable rates. This includes the Energy Return Surcharge.

Where a 4 percent surcharge would not increase power customers' effective rate because the rate is dictated by the market, BPA proposed a 4 percent surcharge be applied to only those rate components that potentially could affect BPA's revenues during the FY 1996 rate period.

### 1.1.5 Procedural History of This Rate Proceeding

Section 7(i) of the Northwest Power Act, 16 U.S.C. §839e(i), requires that BPA's wholesale power and transmission rates be established according to certain procedures. These procedures include, among other things, issuance of a Federal Register Notice announcing the proposed rates; one or more hearings; the opportunity to submit written views, supporting information, questions, and arguments; and a decision by the Administrator based on the record. As noted above, this rate proceeding to adjust wholesale power rates has been combined with the proceeding for BPA's proposal to adjust transmission rates. This proceeding is governed by BPA's rule for expedited rate proceedings, §1010.10 of BPA's Procedures Governing Bonneville Power Administration Rate Hearings, 51 Fed. Reg. 7611 (1986) (hereinafter Procedures). These Procedures implement the statutory section 7(i) requirements.

On December 28, 1994, BPA published a Notice of Intent to Revise Transmission Rates, 59 Fed. Reg. 66946 (1994), and Notice of Intent to Revise Wholesale Power Rates, 59 Fed. Reg. 66947 (1994). Subsequently, BPA published Federal Register Notices of Proposed Wholesale Power Rate Adjustment, 60 Fed. Reg. 8496 (1995), Proposed Transmission Rate Adjustment, 60 Fed. Reg. 8505 (1995), and Hearing and Opportunity for Public Comment Regarding Proposed Comparable Transmission Terms and Conditions, 60 Fed. Reg. 8511 (1995).

BPA's rate proceedings for 1995 and 1996, and the terms and conditions proceeding, began with a Prehearing Conference on February 13, 1995. The proceedings, originally in two dockets, WP-95/TR-95 (wholesale power and transmission rates) and TC-95 (transmission services terms and conditions), subsequently were separated into three different dockets as described below.

At the direction of the Hearing Officers at the February 13, 1995, prehearing conference, an additional prehearing conference was scheduled for March 15, 1995, and additional time was allowed for petitions to intervene. A Federal Register Notice for Additional Prehearing/Settlement Conference for March 15, 1995, 60 Fed. Reg. 11962 (1995), was published on March 3, 1995.

On February 14, 1995, BPA published a preliminary rate proposal in the Federal Register, 60 FED. REG. 8496 (1995). In that proposal, BPA noted that competitive forces are causing a fundamental and significant change in the Pacific Northwest wholesale power market. In light of these competitive forces, BPA determined that its initial proposal should include a 5-year rate as well as a 2-year rate. BPA anticipated that the work necessary to develop such a proposal would take until July 1995.

At the March 15, 1995, prehearing conference, the parties notified the hearing officers that they had been involved in negotiations for a settlement of issues that might affect the hearing schedule and requested additional time to complete the negotiations. The Hearing

Officers acted on petitions to intervene received to that date and set a scheduling conference for March 22, 1995.

On March 17, 1995, most parties to the rate case signed a Settlement Agreement agreeing that BPA would propose to surcharge BPA's current rates for a 1-year period, October 1, 1995, through September 30, 1996, and to extend the Variable Industrial Power (VI) rate which was scheduled to expire on June 30, 1996, through September 30, 1996. The parties also agreed to conduct a separate subsequent process to establish a 2-year and a 5-year rate proposal, and a proposal for transmission services terms and conditions. The Settlement Agreement was an attempt to balance a number of interests, including concerns expressed by customer representatives to BPA's Power Sale Contract renegotiations.

As a result of the March 22, 1995, scheduling conference, the Hearing Officers issued an Order that divided the proceedings previously designated as WP-95, TR-95, and TC-95 into three separate dockets:

A. The 1995 Wholesale Power and Transmission Rate Proceeding was designated WP-95/TR-95, and this 90-day expedited rate proceeding would be conducted pursuant to Section 1010.10 of the Procedures. On May 1, 1995, when BPA issued its initial rate proposal and published it in the Federal Register, 60 Fed. Reg. 21132 (1995).

B. The 1996 Wholesale Power Proceeding was designated WP-96 and the Transmission Rate Proceeding was designated TR-96, and both will be general rate proceedings conducted pursuant to Section 1010.9 of the Procedures. The March 22 Order established a hearing schedule beginning July 10, 1995, to establish BPA's power and transmission rates for the period beginning October 1, 1996, and new transmission services terms and conditions. The schedules adopted by the Hearing Officers for WP/TR-96 and TC-96 afford the parties a hearing process that encompasses a period of 8 months for establishment of BPA's new rate designs including new 2- and 5-year rates, and for establishment of transmission services terms and conditions. (BPA filed its Initial Rate Proposal on July 10, 1995, and will publish its final ROD on April 30, 1996, under the schedule ordered by the Hearing Officers.)

C. The 1996 Transmission Services Terms and Conditions Proceeding was designated TC-96, and will be conducted pursuant to Section 1010.9 of the Procedures concurrently with WP-96/TR-96. The terms and conditions proceeding will be on the same schedule as the 1996 Wholesale Power and Transmission Rates proceedings.

The Hearing Officers set another scheduling conference for March 22, 1995, and, in separate orders issued March 22, 1995, the Hearing Officers: (1) adopted a service list for BPA's 1995 Wholesale Power and Transmission Rate Adjustment Proceeding, 1996 Wholesale Power and Transmission Rate Adjustment Proceeding, and 1996 Transmission

Terms and Conditions Proceeding; and (2) ruled on other procedural matters concerning these proceedings ruled that intervenors who intervened in the dockets designated WP-95/TR-95 and TC-95 on or before March 15, 1995, were admitted as parties for all proceedings noted above.

BPA's initial proposal was filed on May 1, 1995, and was supported by prefiled written direct testimony and studies sponsored by 21 witnesses. Direct testimony was filed by the Public Power Council, Direct Service Industries and Columbia Basin Institute on May 30, 1995. The parties' direct testimony consisted of both their rebuttal to BPA's case and their own direct cases. On June 19, 1995, BPA and the parties filed rebuttal testimony.

BPA responded to 99 data requests concerning the initial proposal and rebuttal testimony. Untranscribed clarification sessions were held on May 5, June 2 and June 4, 1995. Cross examination took place on June 30, 1995. One field hearing was held in Eugene, Oregon, on June 6, 1995, at the request of Emerald Public Utility District. The field hearing was transcribed and the comments received there are part of the record on which the Administrator bases his decisions. See Section 5.0.

Parties submitted briefs on July 10, 1995. Because this proceeding was held pursuant to the rule for expedited proceedings, BPA did not prepare a draft Record of Decision and there will be no briefs on exceptions.

BPA made this ROD available on July 31, 1995.

This ROD, which includes the proposed rates, will be filed with FERC on August 1, 1995. FERC will review the proposed rates for conformance with statutorily-designated review standards, and upon issuance of interim approval, the rates will go into effect on October 1, 1995, for a 1 year period.

## 1.2 Legal Guidelines Governing Establishment of Rates

### 1.2.1 Statutory Guidelines

Section 6 of the Bonneville Project Act (Project Act), 16 U.S.C. § 832e, requires that the Administrator prepare schedules of rates and charges for electric energy sold to purchasers. Under the Project Act, rate schedules become effective upon confirmation and approval by the Federal Power Commission (succeeded by FERC). Section 6 of the Act directs the Administrator to establish rates with a view to encouraging the widest possible diversified use of electric energy. Section 7 of the 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 16 U.S.C. § 838 (Transmission System Act), contains requirements similar to those of the Project Act. Section 9 of the Transmission System 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 System Act. Section 10 of the Transmission System 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 (Flood Control Act) contains ratemaking requirements similar to the Project Act and the Transmission System 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 electric energy, including the amortization of the Federal investment over a reasonable number of years.

In addition to the Bonneville Project Act, the Transmission System Act, and the Flood Control Act, the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839, (Northwest Power Act) provides numerous rate directives. Section 7 of the Northwest Power Act 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, 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) over a reasonable period of years. 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 of the Northwest Power Act 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 comments, 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). The Energy Policy Act of 1992 (EPA'92) sets forth additional ratemaking requirements for transmission rates to be applied in connection with transmission access ordered by the Federal Energy Regulatory Commission.

### 1.2.2 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 Admin., 774 F. 2d 1262, 1266 (4th Cir. 1985).

The United States Court of Appeals for the Ninth Circuit also has recognized the Administrator's ratemaking discretion. Central Lincoln Peoples' Utility District v. Johnson, 735 F.2d 1101, 112029 (9th Cir. 1984) ("[b]ecause BPA helped draft and must administer the Northwest Power Act, we give substantial deference to BPA's statutory interpretation"); PacifiCorp v. F.E.R.C., 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 Admin., 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"); Dep't of Water and Power of the City of Los Angeles v. Bonneville Power Admin., 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).

## 1.3 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). EPA'92 did not in any way alter this process for BPA's transmission rates for FERC-ordered transmission access. H.R. Conf. Rep. No. 1021018, 102nd Cong., 2d Sess., 389 (1992), reprinted in 1992 U.S.C.C.A.N 2480.

### 1.3.1 Firm and Surplus Firm Power Rates and Transmission Rates

With respect to all rates other than those for sales of nonfirm power outside the Pacific Northwest and rates for transmission access ordered by FERC, FERC determines whether: (1) rates are sufficient to assure repayment of the Federal investment in the FCRPS 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 power costs, neither of which are subject to FERC jurisdiction.
Central Lincoln Peoples' Utility District v. Johnson, 735 F.2d 1101, 1115 (9th Cir. 1984).

### 1.3.2 Nonfirm Energy Rates

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). FERC reviews nonregional nonfirm energy rates to ascertain that BPA has designed the 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); United States Dep't of Energy--Bonneville Power Admin., 54 F.E.R.C. ¶ 61,235, 61,294 (1991).

FERC review of BPA's nonregional nonfirm energy rates is based upon the evidentiary record developed by BPA pursuant to section 7(i) of the Northwest Power Act, 16 U.S.C. § 839e(i). Aluminum Company of America v. Bonneville Power Admin., 903 F.2d 585, 592 (9th Cir. 1990). This review is consistent with FERC authority to confirm, reject, or remand BPA's rates.
United States Dep't of Energy--Bonneville Power Admin., 23 F.E.R.C. ¶ 61,378, 61,801 (1983); Central Lincoln Peoples' Utility District v. Johnson, 735 F.2d 1101, 1113 n.6 (9th Cir. 1984).

The Northwest Power Act provides no specific guidance to BPA in how to apply the section 7(k) statutory standards while designing nonfirm energy rates.
Aluminum Company of America v. Bonneville Power Admin., 903 F.2d 585, 598 (9th Cir. 1990). In Aluminum Company, the court noted that BPA has three conflicting obligations in conforming its rates to the section 7(k) statutory standards. BPA must ensure that nonfirm energy is sold at the lowest possible rates consistent with sound business principles, but must also ensure cost recovery and Treasury repayment, while encouraging the most widespread use of electricity. Id. As concerns the requirements of lowest possible rates and widespread use, the court determined that these requirements afford BPA wide latitude in nonfirm energy rate design, providing BPA with so much discretion that there is no law to apply. Id. However, BPA is constrained in its discretion by the other directives in section 7(k), since nonfirm energy rates must be designed with regard to cost recovery and

amortization of the investment of the U.S. Treasury over a reasonable period of years. 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. Part 300 (1993).

## 2.0 SUBSTANTIVE COST RECOVERY ISSUES

### 2.1 Introduction

BPA is a self-financing power marketing agency within the United States Department of Energy. Sales of electric power and transmission services provide BPA's only source of revenue. See Central Lincoln Peoples Util. Dist. v. Johnson, 735 F.2d 1101, 1116 (9th Cir. 1984). BPA's power and transmission rates must produce revenues sufficient to assure repayment of all Federal investments in the Federal Columbia River Power System (FCRPS) over a reasonable number of years after first meeting the Administrator's other costs. 16 U.S.C. § 832g and § 839e(a). At the same time, BPA must set rates with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles. 16 U.S.C. § 839(a)(1). The Revenue Requirement Study determines the level of revenue required to recover all costs of acquiring, conserving, and transmitting electric power, including the repayment of the Federal investment in the FCRPS over a reasonable number of years, and all other costs and expenses incurred by the Administrator pursuant to law. Revenue Requirement Study, WP-95-E-BPA-10.

#### 2.1.1 Development of the Revenue Requirement

In compliance with the FERC Order dated January 27, 1984, BPA determines separate revenue requirements for generation and transmission. United States Dep't of Energy -- Bonneville Power Admin., 26 F.E.R.C. ¶ 61,096. Each revenue requirement (generation and transmission) is comprised of two parts. First, a separate repayment study is prepared for each function to determine the projected annual interest expense and amortization payments on the Federal investment. These two repayment studies are conducted for the rate test period (in this case FY 1996) and extend through the repayment period. Second, projections of annual operating expenses of the FCRPS and planned net revenues are compiled and functionalized to the generation and transmission functions of the FCRPS. Planned net revenues are included in the revenue requirements at sufficient levels to meet planned annual cash requirements and to meet BPA's financial risk mitigation objectives.

BPA must demonstrate that revenues from rates are sufficient to meet two tests. First, revenues must be sufficient to repay the Federal investment within the allowable repayment period. Second, revenues must be sufficient to recover both expenses and planned net revenues in each year of the rate test period. The two tests must be satisfied in both the generation and transmission functions for each year of the rate and repayment periods. Revenue Requirement Study, E-BPA-10, 3-4.

#### 2.1.2 Development of Revenue Requirement for the FY 1996 Rate Period

BPA developed a draft Strategic Business Plan as part of BPA's Competitiveness Project. Revenue Requirement Study, E-BPA-10, 13. The development of the Business Plan includes determination of BPA's spending levels through FY 2002. Id. Development of

these spending levels took into account competitive pressures and cost recovery imperatives. The draft Business Plan was published in June 1994, with preliminary spending levels. Beginning in June 1994, and continuing through the first of January 1995, BPA sought public comment on its Business Plan and spending levels. Throughout this process, BPA continued to revise its Business Plan and spending levels based on comments received. As of January 1995, BPA made the decision to reduce its FY 1996 preliminary spending levels by $40 million. Id., at 14. Subsequently, it became clear that an additional $40 million cost cut would be necessary to improve BPA's competitive position and to ensure total cost recovery. Id., at 14-15. BPA's 1995 initial revenue requirement reflected the spending levels, including an $80 million reduction in costs, developed as part of the Business Plan process. Id.

As part of the Competitiveness Project, spending levels were set on a strategic basis, using a "top down" strategy. Id., 14. This "top down" strategy operates such that first an overall spending ceiling is established, after which various internal BPA organizations develop somewhat more detailed budgets for each program area. At the time BPA published its 1995 initial proposal, BPA still was engaged in the budget process to determine, in greater specificity, the specific budgets for the various programs, given BPA's decision to reduce FY 1996 spending levels by $80 million. Id. at 13.

In FY 1996, BPA is implementing a fish mitigation cost-sharing arrangement with the Administration. The cost-sharing arrangement calls for some relief to BPA from escalating costs due to salmon recovery initiatives, including the 1995 Biological Opinion issued recently by the National Marine Fisheries Service (NMFS). The relief takes two forms: (1) annual credits beginning in FY 1995 against BPA's cash transfers to Treasury under section 4(h)(10)(C) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839b(h)(10)(C);, and (2) to the extent necessary, a reduction in BPA's probability of meeting its annual payments to Treasury.

The Revenue Forecast Study forecasts revenues given a specified set of rates, loads, and market conditions, providing BPA's forecast of revenues for FY 1995 and the 1-year rate period, FY 1996. For FY 1996 rates, two revenue forecasts are prepared: (1) revenues using BPA's 1993 rates and (2) revenues using the adjusted (surcharged) 1995 rates. Revenue Forecast Study, WP-95-E-BPA-11, at 1. Projected revenues, expenses, and adjustments to cash in FY 1995 are used to determine BPA's cash balance at the beginning of the FY 1996 rate period. Revenue Requirement Study Documentation, Vol 1, WP-E-BPA-10A, 77-100. Projected revenues in FY 1996 under current 1993 rates are used in the current revenue test to determine the adequacy of current rates to meet BPA's FY 1996 cost recovery requirements (current revenue test). The current revenue test was not met. Revenue Requirement Study, E-BPA-10, 45. Projected revenues in FY 1996 under the proposed rates are used in the revised revenue test to determine whether the revenue from the surcharged rates are adequate to meet BPA's FY 1996 cost recovery requirements. The revised revenue test demonstrates that the revenues from the

surcharged rates are sufficient to met BPA's cost recovery requirements. Revenue Requirement Study, E-BPA-10, 44-61.

### 2.1.2.1 Evidence to Support the Administrator's Cost Cuts

***Issue***

*Whether the Administrator's direction to executive management and his commitment to make cost cuts totaling $80 million in FY 1996, is sufficient, credible evidence to include in BPA's demonstration that BPA's proposed rates are adequate to recover costs.*

**Parties' Positions**

CBI claims that the "undistributed" cost reduction in revenue requirements is a "fancy way of saying" that BPA's initial Revenue Requirements Study shows an $80-million shortfall for FY 1996. Bell, WP-95-E-CB-01, 5. CBI argues that BPA is attempting to hide this shortfall by referring to it as an "undistributed" reduction in BPA's costs. In conclusion, CBI asserts that the cost reductions are speculative. CBI's Brief, WP-95-B-CB-01, 9.

PPC notes that the record contains evidence that BPA is in fact reducing its expenses by $80 million. O'Meara, WP-95-E-PP-01, 3. PPC points to a statement made by Terry Esvelt, BPA Vice President for Marketing, at the public hearing for this proceeding held at the Emerald Public Utility District offices. Mr. Esvelt said that BPA already has identified how $50-$60 million of the $80 million reduction in costs will be achieved; and that the remaining $20-$30 million of cuts will be made. PPC further refers to BPA statements on the record that denote BPA's pledge to make these cost reductions. Id.

**BPA's Position**

The Administrator is committed to reducing BPA's costs in FY 1996 by $80 million. See Revenue Requirement Study, E-BPA-10, 14. At the time BPA published its initial proposal, BPA management was involved in a budget process to achieve the $80 million in cost reduction. Id. Given the Administrator's directive, BPA management will develop program budgets for FY 1996 that reduce spending level by $80 million. DeWolf, Tr. 37. The final Revenue Requirement Study shows the cost reductions by program. Final Revenue Requirement Study Documentation, WP-95-FS-BPA-10, Chapter 4. The total cost reduction in BPA's FY 1996 budget exceeds 80 million. Id.

**Evaluation of Positions**

CBI claims that the record shows discrepancies between BPA's expected costs and revenues in FY 1996. According to CBI, BPA has attempted to disguise one of these discrepancies by referring to the difference as an undistributed reduction in BPA costs. CBI's Brief, B-CB-01, 18. Because BPA failed to indicate how these cost cuts would be allocated across the various programs, CBI claims that the cost cuts are speculative.

Id., at 19. In effect, CBI questions the Administrator's commitment to achieving cost cuts of $80 million in FY 1996.

Contrary to CBI's allegations, the Administrator is committed to cutting costs in FY 1996. As BPA witness Moorman testified, BPA must be able to manage and control its costs to respond to new market conditions. Moorman, WP-95-E-BPA-13, 8. BPA's ability to control costs is not just a desire but necessary for BPA's financial integrity and ability to survive in the new competitive environment. The competitive market is unlikely to provide BPA with sufficient revenues to cover all its planned costs, including its payments to the United States Treasury, unless BPA fundamentally changes its approaches to marketing and pricing BPA's products and continues to provide competitive rates. Id. To survive in the competitive market, BPA must make fundamental changes in the ways in which it controls costs. Id.

No longer can BPA simply increase its rates to cover cost increases. Id., at 8. Failure to hold the line on BPA's rates within very limited bounds may lead to a situation in which BPA is not able to sustain a sufficient level of revenues over the near- and long-term to recover its costs. Id., at 7. As rates increase or the threat of increasing rates persists, customers will leave or will secure other sources of power, leaving the revenue requirement to be collected from fewer ratepayers, reduced sales, and/or lower-priced alternative markets. After some point, decreasing market share at higher prices will make it impossible to bring in enough revenue to cover BPA's costs, including costs of repaying the Federal investment. Id. Because BPA no longer has the ability simply to raise rates to generate more revenues, the financial flexibility required to manage these risks can be achieved only through fundamental changes in the way BPA markets its products and controls its costs. Id. In addition, if BPA does not take any corrective action, it soon will exceed its borrowing limits from the United States Treasury, further decreasing business flexibility and leaving itself few options to meet its capital requirements other than possibly unsustainable rate increases. Id.

As BPA witness Moorman testified, BPA is taking three principal actions to help ensure that it recovers its costs while maintaining competitive rates: (1) cutting costs aggressively, (2) implementing a fish mitigation cost-sharing arrangement that has been forged with the Administration, and (3) redesigning rates. Id., at 13.

The Administrator's commitment to cutting costs is evidenced in BPA's aggressive actions in managing costs over the past few years. For instance, despite significant and unexpected new costs related to fish mitigation--an estimated $500 million per year--BPA's total operating expenses stayed level for the last 3 years. Id. By the beginning of this year, program reinvention, cost cutting and efficiencies that BPA already has undertaken have resulted in reductions of about $240 million a year, on average, from the planned operating expenses for FYs 1996-2000 that were established when rates were last set in 1993. Id. BPA has reduced its workforce by about 350 Federal employees since the Competitiveness Project was initiated. Id. BPA contractors will have been reduced by about 200 by the end of FY 1995. A goal of reducing the overall workforce

by 1,000 by the end of FY 1997 is on target. Id. Further examples of cost-cutting and efficiency include: terminating two partially completed nuclear plants, WNP Nos. 1 and 3; in cooperation with the Bureau of Reclamation, improving Grand Coulee Dam generation efficiency, thereby adding revenues; early cleanup of the Ross Complex Superfund Site; and negotiating an agreement in principle to resolve delivery of the Canadian entitlement downstream benefits under the Columbia River Treaty, thus saving alternative resource costs and the costs of building a new transmission line. Id., at 14.

As BPA witness Moorman testified, all elements of the budget are being considered. Id. In particular, BPA is examining termination of resource acquisition projects. Id. All current generating resources both on-line and under development are being reviewed in order to achieve savings of about half their costs. Id. In addition, planned transmission capital investments are being reduced significantly. Id. Finally, BPA and the Administration have agreed to share the costs of BPA's increasing fish mitigation costs (section 4(h)(10)(C) credits) beginning in FY 1995. Issues associated with section 4(h)(10)(C) credits and reduced accumulation of cash reserves are discussed in section 2.1.2.4, infra.

Thus, contrary to CBI allegations that the cost cuts are speculative, the record contains ample evidence that BPA was making progress to identify and allocate the cost cuts simultaneous with the rate hearing process. See Revenue Requirement Study, E-BPA-10, 14. As PPC observed, BPA's Vice President for Marketing stated at the public field hearing in this proceeding that $50 to $60 million of the $80 million in promised expense reductions had been identified and that the Administrator was committed to the remaining amount of promised reductions, O'Meara, E-PP-01, 3.

Moreover, during cross-examination, witness DeWolf testified that as of June 30, 1995 (the day the cross-examination was conducted) estimates had been received from BPA's budget support group that included an estimated $80 million in expense reductions. Tr. 32. Although he acknowledged that these estimates had not yet been reviewed by the BPA witnesses for inclusion in analyses and studies, witness DeWolf indicated that such estimates would be reviewed, corrected if necessary, and included in BPA's final rate proposal. Id., at 30, 32. Witness DeWolf further indicated his expectation that, given the Administrator's direction to implement the $80 million in expense reductions, the entire $80 million in cuts would be made. Id., at 32, 33, and 37.

***Decision***

*The Administrator is committed to reducing BPA's costs in FY 1996 by $80 million. BPA's ability to control costs is for BPA's financial integrity and ability to survive in the new competitive environment. The Administrator's commitment to cutting costs is evidenced in BPA's aggressive actions in managing costs over the past few years. The Administrator's direction to executive management, and his commitment to make cost cuts totaling $80 million in FY 1996 is sufficient, credible evidence to include in BPA's demonstration that BPA's proposed rates are adequate to recover costs.*

### 2.1.2.2 Program and Spending Levels

*Issue*

*Whether the Administrator's budget decisions are appropriately the subject of a section 7(i) proceeding and subsequent judicial review.*

**Parties' Positions**

CBI states the Administrator's precise budget reduction decisions will be made sometime after the close of the record of this proceeding. CBI Br., B-CB-01, 1. Therefore, CBI argues that the Administrator's decision will not be based on evidence in the rate case record. Id.

**BPA's Position**

Programs and spending level determinations, which include specific spending level cuts, are not a ratemaking issue and therefore are not an issue to be decided in a 7(i) proceeding. Administrator's Record of Decision for the 1993 Final Rate Proposal, WP-93-A-02. Sound business principles dictate that the Administrator consider all relevant information in making decisions on program and spending level issues. Id.

**Evaluation of Positions**

CBI states that the Administrator's decision will be made sometime after the close of record of this proceeding, implying that the Administrator's decision should be based on evidence in the rate case. CBI Br., B-CB-01, 1.

BPA previously addressed the issue of the appropriateness of spending level issues being addressed within the context of a 7(i) rate proceeding in the Administrator's Record of Decision for the 1993 Final Rate Proposal, WP-93-A-02, July 1993. In submitting the rates to FERC, BPA did not submit testimony relating to the amount of money that BPA should plan to spend on its various programs. FERC found that the record, excluding testimony on spending levels, was adequate for Commission review. 67 F.E.R.C. ¶ 62,351 (June 20, 1994). The following discussion is based in part on the decision of this issue as considered in the 1993 rate proceeding.

BPA's Federal Register notice for this proceeding indicated that spending levels, with limited exceptions, would not be considered in this proceeding. 60 Fed. Reg. 8496 (1995); 60 Fed. Reg. 8505 (1995). These directions are a lawful constraint on the hearing officer's authority. Administrative Procedure Act, 5 U.S.C. § 556(c) ("Subject to the published rules of the agency and within its powers, employees presiding at hearings may . . . (5) regulate the course of the hearing . . . [and] (9) dispose of procedural requests or similar matters."); see also "Attorney General's Manual on the Administrative

Procedure Act," 75 (U.S. Department of Justice, 1947) ("The phrase 'subject to the published rules of the agency' is intended to make clear the authority of the agency to lay down policies and procedural rules which will govern the exercise of such powers by presiding officers . . . For example, if an agency provides by rule that the fact of citizenship must be established in a prescribed manner, the hearing officer must conform to such rule in exercising his power to 'rule upon offers of proof and receive relevant evidence.'")

Pursuant to the Transmission System Act, the Administrator is authorized to expend monies in the BPA fund of the United States Treasury subject only to congressional limitation or directive. 16 U.S.C. § 838i(b). BPA does not receive annual congressional appropriations. Instead, the Transmission System Act grants BPA a permanent appropriation of all money in the BPA fund, which consists primarily of BPA's receipts from the sale of electric power and transmission services and from the sale of bonds pursuant to BPA's borrowing authority.

As an element of the Federal budget, BPA's spending levels undergo annual scrutiny by the President and by Congress. In preparing the Federal budget, the President has exclusive authority to "prescribe the contents and order of statements in the budget on expenditures and estimated expenditures." 31 U.S.C. § 1104(b). The budget must include "estimated expenditures and proposed appropriations the President decides are necessary to support the Government in the [next] fiscal year." 31 U.S.C. § 1105(a)(5). Once the President submits the budget to Congress, Congress is authorized and required to adopt a budget which "shall set forth appropriate levels for the fiscal year beginning on October 1." 2 U.S.C. § 632(a). Unless the President reduces BPA's proposed spending levels or Congress limits BPA's spending authority in an annual appropriations act, BPA is authorized to expend the money in the BPA fund. Thus, the Federal budget process, not the rate case, is the forum for determining BPA's spending levels.

Pursuant to the Transmission System Act, BPA is authorized, though not required, to spend the funds contained in its annual budget submission to Congress. 16 U.S.C. § 838i(b). Assuming, arguendo, that the BPA "top down" budgeting process involving the "$80 million in undistributed reductions," had been completed earlier in the ongoing 1995 rate proceeding, identifying the specific program cuts envisioned by BPA might have invited attempts to then establish the spending levels in litigation -- an outgrowth of BPA's seeking to disprove what CBI alleges in its brief is the "revenue requirement shortfall" due to "lack of identified measures." For example, see Bell, E-CB-01, 3 ("BPA has significantly reduced services, reduced system reliability by cutting transmission investments and O&M . . . [and] . . . is in the process of abandoning its statutory responsibilities as the regional facilitator for implementing the Northwest Power and Conservation Plan, (sic) and the Regional Fish and Wildlife Plan.")

Any attempts to compel BPA to adjust its spending levels through litigation usurps the authority granted by the Transmission System Act and intrudes on Congress's prerogative to determine BPA's spending levels. Congress has already reviewed BPA's

budget for FY 1996. Unless Congress passes legislation limiting BPA's authority, BPA is authorized, though not required, to expend the funds contained in its budget submission. Subjecting the final budget decisions on spending levels to the outcome of the rate case adds a criterion limiting BPA's authority that was not contemplated by the Transmission System Act or any other statute.

In BPA's 1993 rate proceeding, parties argued that, pursuant to section 7 of the Northwest Power Act, they had a right to present evidence related to BPA's proposed rates. Since spending levels affected rates, the parties concluded that they had the right to litigate BPA's spending levels in the rate case. See Administrator's Record of Decision for the 1993 Final Rate Proposal, WP-93-A-02, 322. As all BPA actions ultimately may affect BPA's rates, the interpretation urged by the parties in BPA's 1993 rate proceeding, had it been adopted, would potentially have subjected every business decision BPA makes to the rate case. As the parties in the 1993 rate case acknowledged, however, the purpose of the rate case is to set rates. Section 7 of the Northwest Power Act cannot be read in isolation from the Transmission System Act, the Federal budget process, and the various public processes mandated by the Northwest Power Act in which BPA makes its program and spending level decisions. The Northwest Power Act's procedural provisions must be construed consistently with these other laws and mandates if possible.

Once BPA's programs and spending levels are established, BPA's load and revenue forecasts, cost allocations, and rate design determine BPA's rates. See 60 Fed. Reg. 21,132 (May 1, 1995). Parties to the 7(i) proceedings have the right to contest BPA's proposals on these questions, thereby contesting the proposed rates. Resolution of these issues in the final decision justifies the rates, thereby satisfying the Northwest Power Act's procedural requirements. In short, BPA must demonstrate that, given its spending levels as established through other legally mandated means, its rates are appropriate.

In the 1993 rate proceeding, various parties' proposals demonstrated that spending levels cannot reasonably be established in a 7(i) rate proceeding. For example, the Joint Customers proposed that BPA reduce its staffing of the Residential Exchange Program and make significant and fundamental changes in the way that BPA administered the program. Schoenbeck, WP-93-E-JC-04. Yet, staffing levels and program administration are business decisions requiring consideration of all available information. Raynor, WP-93-E-BPA-24, 9. Attempting to decide on staffing levels in the context of the rate case would not permit the proper consideration of BPA's legal responsibilities or the Residential Exchange program's workload. Id. A decision on staffing, a spending level decision, would have required consideration of all of the various responsibilities of the Exchange Program and its expected future workload. Resolution of such issues would require a vast expansion of the 7(i) proceeding.

More significantly, the adversarial process of the rate case forum is not a sensible or appropriate forum for making such business decisions. It is simply not feasible for BPA to make business decisions such as this through litigation, based on a rate case record

that does not permit consideration of all relevant concerns. The same considerations apply with equal force in the current BPA rate proceeding, in which identification of the nature and degree of program cuts following from the $80 million in undistributed expense reductions would have, in the manner suggested by CBI's testimony, likely initiated a debate concerning whether and to what degree BPA had "reduced system reliability," or "abandon[ed] its statutory responsibility as regional facilitator for implementing the Northwest Power and Conservation Plan, and Regional Fish and Wildlife Plan", or would have raised similar programmatic issues of interest to other individuals. WP-95-E-CB-01 at 3.

Although PPC appended a letter to BPA concerning program level reductions to its witness' testimony, PPC's witness indicated that in doing so PPC merely wished to rebut the assertion of CBI's witness that in the event of a revenue shortfall BPA had no option other than failing to meet its scheduled Treasury payments. Tr. 25.

The Administrator's Record of Decision for the Final 1993 Rate Proposal (1993 ROD) contains additional discussion of the inappropriateness of attempting to establish spending levels in the isolated context of the rate proceeding. Several other factors and issues apply in such circumstances that are cited in the discussion located in the 1993 ROD at page 324 et seq., which is incorporated by reference herein. One such issue involves disregarding the interests of various parties who are involved in regional forums and consultations, but who may not be represented in the 7(i) rate proceedings. Similarly, contractual interests may involve parties affected by spending level decisions who would be excluded from participation in decisions made solely in BPA's rate case. Conversely, the rate case could become a forum for collateral interests to litigate their individual interests, based on an asserted nexus to the rate making process. (E.g., disappointed bidders would argue that the rate case should provide them a forum for arguing that their bid was in fact more economical or cost-effective for BPA, such that the rate case would become a forum for evaluating any alleged "cost reduction" and savings measure that might potentially serve to reduce costs for BPA ratepayers.)

Decisions on spending levels can and do involve matters of judgment in such areas as economic uncertainties, assurances as to continuity of service, and BPA's environmental commitments to protect and enhance the region's natural resources. Attempting to resolve such complex matters in the rate forum is ill-advised, since ultimately there would be no limit to the issues that could be raised in the rate case forum. BPA might well be compelled to run its entire business in the rate case. No business, and no government agency, can possibly operate in such a manner, effectively limited by procedural requirements and facing the prospect of having its decisions in multiple areas constantly litigated.

The essential need for balancing the requirements of program funding, cost recovery and Treasury repayment, assuring the Region of an adequate, economic and reliable power supply, and the various statutory directives of the Northwest Power Act and other related laws indicates that the Administrator must exercise his discretion in determining

the appropriate balance of cost incurrence. The Administrator's discretion, and the deference that must be accorded to the Administrator's exercise of his discretion, is well recognized. Aluminum Co. v. Central Lincoln Peoples Util. Dist., 467 U.S. 380, 389 (1984). In this case, the Administrator determined that in balancing the need for program funding with the need to provide competitive rates--and thus demonstrate cost recovery and timely Treasury repayment--it was necessary to implement additional reductions to spending level funding in the amount of $80 million.

The Administrator's decision to make these reductions, and his charge to agency executives to implement such additional increment of savings, is uniquely and exclusively within his authority as the individual charged by law with implementing the potentially conflicting directives of the Northwest Power Act and other BPA organic statutes. The Administrator is permitted, via congressional approval of BPA's budget, to expend such funds as are available to him in the BPA Fund. Yet, given the Administrator's decision that further spending level reductions are appropriate, the Administrator is also permitted to exercise his judgment to limit the amount of such expenditures that he is permitted, but not required, to make.

**Decision**

*BPA's budget is an element of the Federal budget and is therefore not an appropriate subject for a section 7(i) proceeding and subsequent judicial review. Moreover, sound business principles dictate that the Administrator consider all relevant evidence in making budgetary decisions and not be limited to the rate case record.*

### 2.1.2.3 Probability of Treasury Repayment

***Issue***

*Whether the 85 percent probability of repayment for FY 1996 indicated in BPA's final rate proposal is legally sufficient, and acceptable as a matter of policy.*

***Parties' Positions***

In its brief, CBI states that BPA testimony recommends an unlawful course of action by ignoring BPA's repayment obligation to the United States Treasury. CBI Br., B-CB-01, 14. Stating that Treasury repayment is an overarching statutory obligation, CBI cites statutory standards applicable to BPA's rates under section 7(a) of the Northwest Power Act, 16 U.S.C. § 839e(a), and section 7(k) of the Northwest Power Act, 16 U.S.C. § 839e(k). CBI also quotes from the Federal Energy Regulatory Commission's (FERC) order confirming and approving BPA's 1993 Wholesale Power and Transmission Rates on a final basis. United States Department of Energy--Bonneville Power Administration, 67 F.E.R.C. ¶ 61,351, 62,217 n. 11 (1994).

In presenting the quotation set forth below, CBI states that "FERC described its independent analysis of the PRS [Power Repayment Study] to determine whether the rates met the legal standard of sufficiency to assure repayment of the Treasury." CBI Br., B-CB-01, 16.

> The Commission compared the actual investment repayment to date with a bench mark level of payment based upon a compound interest amortization schedule. As of September 30, 1992, BPA has repaid $2.1 billion of the $3 billion, compared with 66.4 percent for 1988, and 68.8 percent for 1990. While BPA has not yet reached the benchmark level, the Commission considers the level of intermediate repayment reasonable, given that BPA's repayment record has steadily improved in recent years.

Id.

The DSI's witness stated that BPA's ability to recover its costs over a reasonable number of years requires BPA to evaluate the consequences of its actions over time. Waddington, WP-95-E-DS-01, 5. The DSIs assert that it is prudent for BPA to take somewhat more risk as concerns Treasury payment in FY 1996 so that it will improve the likelihood of future recovery of Federal investment. Id. Although noting that the DSIs do not contest BPA's proposed surcharge rate the DSIs urge that BPA forego the proposed 4 percent rate increase, asserting that BPA would be much more likely to retain market share for the longer term if it held rates constant until its new competitive rates were ready. Id. at 6.

The PPC expresses the belief that sound business principles argue for BPA to establish rates at the lowest level possible to meet costs and to "sustain [BPA's] near and long-term competitive position." PPC Brief, B-PP-01, 1. PPC observes that if a rate increase less than the 4 percent level proposed by BPA for FY 1996 serves to enhance BPA's near- and long-term competitive position, avoiding loss of load, and permitting BPA to create "sustainable revenues adequate to recover appropriate and necessary costs," then BPA should adjust its amount of proposed rate increase to reflect market conditions. PPC asserts that statutory criteria requiring rates to be established "consistent with sound business principles" would include "assuring continued repayment over time by maintaining a competitive market presence." PPC suggests that BPA's statutory charge recognizes an interest in recovery of costs over the long-term, and not in "maximizing revenues in 1 year at the expense of subsequent years." Id. at 2-3.

PPC takes issue with CBI's witness' statement that absent the 4 percent surcharge stipulation, BPA would be able to "adjust rates to match costs." O'Meara, E-PP-01, 1. PPC notes that CBI has failed to consider the impact of a rate adjustment above the proposed 4 percent level on BPA's loads. PPC states that "Rate increases become counterproductive at some point as revenue losses due to loss of loads exceed the revenue gains from higher rates." Id. PPC also notes that CBI failed to consider any elasticity when positing a potential 10 percent increase in BPA's rates. Id., Attachment 1, page 1.

**BPA's Position**

BPA's failure to limit rate increases could lead to circumstances where BPA would be unable to sustain a sufficient level of revenues over the near- and long-term to recover its costs. Moorman, E-BPA-13, 7. As rates increase or the threat of rate increases persists, customer loads will decline, leaving BPA's revenue requirement to be collected from "fewer ratepayers, reduced sales, and/or lower-priced alternative markets." Id. Ultimately, decreasing market share due to higher rates will frustrate cost recovery, including Treasury repayment. Id.

**Evaluation of Positions**

As noted in the direct testimony of both the DSI and PPC witnesses, however, BPA cannot consider the likelihood of Treasury payment for FY 1996 in isolation from BPA's long-term obligation to recover its costs and effect timely Treasury repayment in future years. Waddington, E-DS-01, 5-6; O'Meara, E-PP-01, 1. As indicated in PPC's rebuttal to CBI's direct testimony, the elasticity effects and potential loss of load due to rate increases were not considered by CBI. Id. If BPA fails to constrain its rate levels, BPA may not earn sufficient revenues over the near- and long-term to recover its costs. There is a diminishing return associated with substantial rate increases because customers will leave or secure other sources of power. Decreasing market share at higher prices will make it impossible to bring in enough revenue to cover costs, including costs of repaying the Federal investment. Moorman, E-BPA-13, 7, lines 13-22. PPC's witness observes that rate increases are counterproductive over time to the degree that loss of loads lead to revenue losses. O'Meara, E-PP-01, 1. PPC notes that that consideration of BPA's statutory criteria to establish rates consistent with sound business principles argues for BPA to assure its ability to assure repayment over time, and that this would thus require BPA to maintain a competitive market presence. PPC Brief, B-PP-01, 2-3.

As concerns BPA's long-term ability to assure cost recovery and Treasury repayment, CBI miscomprehends the nature of FERC's review of BPA's rates when it cites, in isolation, footnote 11 from FERC's Order Approving BPA's 1993 Wholesale Power and Transmission rates. CBI Br., B-CB-01, 14. CBI indicates that FERC's "benchmark" comparison of BPA's cumulative repayment of Federal investment is an "independent measure" of the legal sufficiency of BPA's rates. Id. CBI's interpretation is erroneous.

In the cited FERC Order, United States Department of Energy--Bonneville Power Administration, 67 FERC ¶ 61,351 (1994), the Commission indicates that the statutory criteria ". . . only requires that the Federal investment be repaid sometime within the repayment period . . . ." Id. at 62,217. Yet the Commission also notes that

> some intermediate level of repayment should exist to ensure that repayment will occur by the end of the fiftieth year. The traditional measure of the adequacy of BPA's revenues has been the power repayment study (PRS). BPA's generation and transmission PRSs indicate that the future revenues collected under the

proposed rates will be sufficient to recover the Administrator's total system costs of producing and transmitting the electric power and energy, including the recovery of the remaining Federal investment, with interest, over the remaining repayment period.

Id.

Contrary to CBI's implication, however, the Commission's analysis referenced in footnote 11 is not an independent analysis of BPA's then current 1993 rates, but is instead a confirmation that BPA had thus far in the repayment period made an adequate showing of repayment. Footnote 11 speaks of the Commission's evaluation of BPA's historic levels of repayment, and the demonstration that some "intermediate level" of repayment exists during the repayment period.

The Commission compared the actual investment repayment to date with a benchmark level of payment based upon a compound interest amortization schedule. As of September 30, 1992, **[the day prior to the beginning of the rate period for BPA's 1993 rates which the Commission was approving in the order]** BPA has repaid $2.1 billion of the Federal investment. This comprises 70.0 percent of the benchmark amount of $3 billion, compared with 66.4 percent for 1988, and 68.8 percent for 1990. While BPA has not yet reached the benchmark level, the Commission considers the level of intermediate repayment reasonable, given that BPA's repayment record has steadily improved in recent years.

The Commission noted that although BPA has not yet reached the Commission's "bench mark" based upon a "compound interest amortization schedule," the level of intermediate repayment is nonetheless reasonable given the improvements in BPA's repayment record over the prior years between 1988 and 1992, a 4-year period. Id. Ultimately, BPA's success in meeting the Commission's "benchmark" for an intermediate demonstration of the likelihood of full repayment over the entire repayment period will not be based on a single rate period, or a single year in isolation. Instead it will be based upon BPA's ability to demonstrate a reasonable level of the likelihood of full repayment over a period of years. As PPC has recognized, BPA's interest is in cost recovery over the long-term, and not in "maximizing revenues in 1 year at the expense of subsequent years." PPC Br., B-PP-01, 2-3.

CBI appears to confuse the pace of repayment—the matter dealt with by the Commission—with BPA's probability of making its scheduled amortization and interest payments in FY 1996. As indicated earlier, market pressures and BPA's need to recover costs over time justify the probability of repayment achieved through the rates established herein. The 85 percent probability standard in this case does not differ from the probability standard that BPA set its rates to achieve in its 1993 rate filing. Given the emergence of a strongly competitive power supply market since BPA made that filing, BPA should consider it continuing ability to set rates with an 85 percent repayment probability a significant success.

CBI also appears to misapprehend the legal significance of the probability of repayment achieved in each case. Consistent with sound business principles, BPA's rates are to be established to assure repayment to the U.S. Treasury over a reasonable number of years, after first meeting BPA's other costs. 16 U.S.C. § 839(a)(1). So long as BPA pays the investment within the repayment period, its repayment is consistent with law. 67 F.E.R.C. ¶ 61,351 at 62,217; DOE Order RA 6120.2. The traditional repayment approach comports with this view.

The traditional repayment approach is described in H.R. Rep. 1409, 85th Cong., 2d Sess. 10 (1966), dealing with construction of the Grand Coulee Third Powerhouse.

> The repayment studies are based upon year-by-year forecasts of system revenues and costs over the repayment period. Revenues are applied first to pay the costs of operation, maintenance, replacements, and interest. All remaining revenues are applied to repay the capital investment in commercial power facilities, and irrigation assistance as it falls due. Accordingly, there is no annual schedule of capital repayment. The test of the sufficiency of revenues is whether the capital investment can be repaid within the overall repayment period established for each power project, each increment of investment in the transmission system, and each block of irrigation assistance. Hence, repayment may proceed at a faster or slower pace from year to year as conditions change. Annual operating costs and revenues, of course, may vary from year to year, as they are affected by extremes of weather conditions, streamflows, current economic conditions, changing markets, and the absorption of new projects into the system.
>
> This approach to repayment scheduling has the effect of averaging the year-to-year variations in costs and revenues over the repayment period.
>
> This results in uniform cost per unit of power sold, and permits the maintenance of stable rates for extended periods. (BPA, for instance, has maintained the same rate level from its inception until now.) This facilitates the orderly marketing of power and permits BPA's customers, which include both electric utilities and electroprocess industries, to plan for the future with assurance.

See also 112 Cong. Rec. 8423 (April 19, 1966)(Rep. Aspinall).

In some respects, BPA's risk mitigation approach—its approach of seeking to achieve a targeted repayment probability for the rate test period—could be viewed as clashing with the traditional repayment approach approved by Congress in

connection with construction of the Grand Coulee Third Powerhouse. BPA's case-to-case approach of determining the appropriate level of risk mitigation to assure cost recovery may mean that the stability just described is not achieved because the risks are different in each case and the level of risk mitigation must consequently be different. However, BPA's view is that the absence of such risk mitigation measures could cause much greater instability over the long run due to resulting pressures for BPA repayment reform. In addition, the risk mitigation approach may be characterized as an annual operating expense. On balance, the greater long-term threat warrants reasonable and adaptable risk mitigation measures and ensures that, over time, rates are as stable as reasonably possible. The probability of repayment achieved in this case satisfies those considerations.

**Decision**

*The need for BPA to maintain market share in order to effect long-term recovery of cost and Treasury repayment has been adequately demonstrated in the record. For purposes of retaining customer load, BPA must position itself to meet competitive market conditions on a long-term basis, so as not to imperil its ability to effect complete repayment of the Federal investment on a long-term basis over the remaining historical repayment period. Given the compelling need for BPA to make a demonstration of both its ability and willingness to meet competition and retain its market share, the probability of Treasury repayment demonstrated in BPA's final rates for this proceeding is adequate. As a matter of fiscal policy and law, BPA cannot reasonably act to disregard the market imperatives that if ignored, would ultimately frustrate BPA's ability to achieve cost recovery.*

**Issue**

Has BPA properly calculated the probability of Treasury repayment in this case.

**Parties' Position**

Columbia Basin Institute

In his direct testimony, CBI's witness indicates that the results of the ToolKit model (used by BPA to determine repayment probability)-- using a 5-year reserve funding sequence--were of no value in determining repayment probability on a 1-year basis. Bell, E-CB-01, 12-13. For purposes of assessing the probability of Treasury repayment, CBI's witness assumed that BPA's initial FY 1996 reserves would be $87 million, which he refers to as the "March estimate," stating "[l]et us assume that BPA's March estimate is more accurate." Id., 15. CBI's witness then states that a net risk pool of $249 million, consisting of $87 million in first year reserves, plus $162 million, minus $50 million in short-term cash reserves, would provide BPA a first year probability of repayment of 84.5 percent. In having elected to use the $87 million "March estimate" of initial FY 1996 cash reserves, CBI's witness indicates that he is not clear as to why BPA moved from a

March estimate of $87 million in initial reserves for FY 1996 to a "May estimate" of $223 million. Bell, E-CB-01, 15. Id. 12. CBI then implies by demonstration that an appropriate way to calculate the probability of making all the payments in a multi-year period is to multiply the probabilities of each year together. Id. 15.

In formulating his own methodology for identifying the cumulative probability of repayment in a given year, CBI's witness states that the cumulative probability of repayment in a given year is the decremental probability for the normally distributed Short Term Risk Evaluation and Analysis Model (STREAM) input associated with the aggregate sum of expected cash balances (from the first year of the model to the current year) minus the $59 million mean value of STREAM input distribution, then multiplied times the number of previous years in the sequence. Bell, E-CB-01, 13.

CBI concludes that in calculating repayment probability in this case, that the ToolKit is "not really needed." Id. 14. CBI suggests that the STREAM distribution used in the ToolKit amounts essentially to a normal distribution function with a mean of -$59 million, and that this normal distribution function ought to be used in place of the ToolKit itself for calculating the probability of BPA making its Treasury payments. Id. 11 CBI's witness also observes, however, that "[s]ince BPA has not allowed sufficient time to fully examine the STREAM model, I cannot comment on the robustness of STREAM assumptions or methodology at this time." Id.

The analysis performed by CBI concludes that the probability of BPA making its Treasury payment in FY 1996 is between 50 percent and 60 percent. This was calculated using figures for projected net revenues developed by CBI. Id. 16.

**BPA's Position**

The ToolKit model used in this case consists of a computer spreadsheet used to evaluate the Treasury repayment probability for FY 1996. The ToolKit also included logic for evaluating Treasury repayment probability for a 5-year period. Inputs to the model included the first 5 years of the 10-Year Financial Plan STREAM distribution which comprise 500 scenarios. The mean of the cash flows for all 5 years in the set of 500 scenarios is -$59 million. Five years are used because the 1 year rate test period (FY 1996) and 4-year Section 7(b)(2) rate test period (FYs 1997-2000) comprise 5 years. Only the amount for the first year of each scenario is relevant for evaluating the FY 1996 Treasury payment probability. The mean of the first year of the distribution is -$69 million. DeWolf, et al., E-BPA-22, 9-10. With the exception of the absence of an Interim Rate Adjustment and a Program Cost Deferral mechanism (which are inapplicable to a single year rate period such as that in this instant case) BPA's implementation of its risk mitigation policy remains unchanged from its 1993 rate proceeding. DeWolf et al, E-BPA-16, 8.

BPA observed in its testimony that although its ToolKit results would permit evaluation of Treasury repayment probability for a 5-year period, it would also permit such information

to be determined for any single year within that 5 year period. DeWolf, et al, E-BPA-22, 8. The $223 million "May estimate" cited in CBI's testimony corresponds to BPA's Amended First Quarter Review. Id., 8-9 BPA's analysis of Treasury repayment probability used the $223.9 million "May estimate" plus $162 million in projected FY 1996 reserves. Revenue Requirement Study Documentation, E-BPA-10A, Volume 1, 301.

BPA calculates a probability of making its FY 1996 Treasury payment of 85 percent. Final Revenue Requirement Study, WP-95-FS-BPA-10, 58.

**Evaluation**

Contrary to the assertions of CBI's witness, the ToolKit is well suited to providing calculations of Treasury repayment probability on a 1 year basis for FY 1996. This requires, however, that only the first year result (of each 5 year funding sequence result provided by the ToolKit) be used in assessing the repayment probability for FY 1996. CBI apparently attempted to use the ToolKit results to extrapolate repayment probability for subsequent years beyond the single year 1996 rate period. Not only is such an extrapolation irrelevant to the single year 1996 rate period, but since CBI's witness did not limit his use of the repayment probability results to the "first year" results applicable to the 1996 rate period, the probability estimate that CBI produces is flawed. CBI's analysis was further flawed by the use of the mean value of STREAM input for the 5-year period (-$59 million), rather than the mean for the first year distribution amounts, which is -$69 million.

BPA's use of $223 million in the initial reserve balance for FY 1996 was based on BPA's Amended First Quarter Review. As indicated in BPA's testimony, the replacement of the "March" estimate of $87 million for FY 1995 ending reserves with the "May" estimate is based upon the replacement of the "March" projections with reports of actual transactions. DeWolf et al, E-BPA-22, 8. The updated information was provided in BPA's initial direct case. Revenue Requirement Study Documentation, Vol. 1, E-BPA-10A, 89. The use of this updated information provides a more accurate base assumption for assessing Treasury repayment probability than was adopted by CBI. DeWolf et al, E-BPA-22, 8. CBI's witness inexplicably elected to use the lower, outdated "March estimate," without any apparent justification. Bell, E-CB-01, 15.

The 50-60 percent probability of Treasury payment in FY 1996 posited by CBI was, as noted above, based on figures for net revenues developed by CBI. Bell, E-CB-01, 16. These net revenues, which are considerably less than those developed by BPA, are not only inappropriately based upon the "March" estimate of initial reserve balance discussed above, but are also based upon CBI's "unique" characterization of reductions to BPA's payment obligations as revenue "shortfalls." In its probability calculations, CBI uses these alleged "shortfalls" to reduce reserves, which then ultimately yields CBI's calculation of 50 -60 percent probability of repayment in FY 1996.

As discussed extensively in Section 2.1.2.5, supra, however, CBI's characterization of undistributed reductions, 4(h)(10)(C) credits, and other revenue "recoupments" as "shortfalls" is erroneous and misleading. CBI inappropriately reduces BPA's reserve estimate as part of its technical analysis of the probability of BPA's Treasury repayment, because it erroneously characterizes various sources of revenue or revenue credits as "shortfalls". Thus, CBI's technical analysis is based upon faulty assumptions, and is inherently unreliable and suspect. CBI's subsequent probability assessment, following from its flawed technical analysis, is similarly suspect, and must be disregarded.

***Decision***

*CBI's alternative calculations of Treasury payment probability are flawed in several material respects, based on CBI's erroneous assumptions and faulty operation of the ToolKit model, or the same erroneous assumptions as applied in CBI's "alternative" probability assessment. CBI's critique of BPA's analysis, expressed via CBI's alternative analysis, provides no reliable indication that BPA's calculation of Treasury repayment probability is suspect. BPA's calculation of Treasury repayment probability, based upon the same risk mitigation policy as used in BPA's 1993 rate proceeding, is thus uncontroverted in the record, yet supported by the testimony of BPA's witnesses. BPA's reliance on the use of the ToolKit model for the calculation of Treasury repayment probability for FY 1996 is thus appropriate, and the resulting probability of 85 percent in the case will be used as the final probability determination.*

### 2.1.2.4 Section 4(h)(10)(C) Credits

***Issue***

*Whether BPA's reliance on section 4(h)(10)(C) credits as an offset to its otherwise payable Treasury obligations violates BPA's statutory ratesetting obligation to establish rates to, in part, assure repayment over a reasonable number of years, or otherwise violates sound business principles.*

**Parties' Positions**

CBI asserts that BPA has resorted to an "accounting ledgerdemain" in its application of approximately $120 million in section 4(h)(10)(C) credits for FY 1996. CBI Br., B-CB-01, 19. CBI argues that use of the section 4(h)(10)(C) credits is analogous to a debtor paying off delinquent credits cards with newly borrowed money, and that BPA's reliance on section 4(h)(10)(C) credit in this case is not a sound business practice. Id. CBI also argues that the fact that BPA has not used these "credits" to build reserves, while also raising rates to "stabilize" BPA revenues, fails to conform with BPA's legal obligation to raise sufficient revenues to meet its Treasury obligations. Id. at 20.

**BPA's Position**

The section 4(h)(10)(C) credit and the use of the annual credits aid BPA in making its annual Treasury payments. Tr. 34-36. Actions to reduce BPA's current FY Treasury payment obligation, and increase BPA's financial reserves to financial obligation is consistent with sound business principles.

During cross-examination, BPA's witnesses confirmed these amounts, indicating that the $56.3 million for FY 1995 would be treated as a financial reserve for FY 1996, since it would serve to reduce BPA's ending FY 1995 Treasury payment obligation by $56.3 million. Tr. 34-36. See also DeWolf, et al., E-BPA-22, 9.

**Evaluation of Positions**

Contrary to CBI's assertions, BPA's witnesses did not state that the reduction of $56.3 million of BPA's Treasury payment obligation was an accounting "ledgerdemain." Tr. 34-37. Instead, consistent with BPA's direct and rebuttal testimony, BPA's witnesses noted that application of the 4(h)(10)(C) credit effectively reduces BPA's annual cash transfers to Treasury. Id. 35.

In it's analogy to "credit card debt" CBI implies that use of the 4(h)(10)(C) credit serves to increase BPA's overall debt, such that it follows that the use of the 4(h)(10)(C) credit is contrary to sound business principles. The implication is misleading and incorrect. Use of the 4(h)(10)(C) credit is in the nature of a "recoupment" of funds previously expended. Application of the FY 1995 credit amount of $56.3 million not only serves to reduce BPA's cash transfers to Treasury, but contributes to the ending FY 1995 reserve amounts of $222.9 million. DeWolf, et al., E-BPA-22, 9. CBI's conclusion that BPA has not used the 4(h)(10)(C) credit to build reserves is thus not only incorrect, but apparently ignores the record evidence of BPA's use of the $56.3 million "credit" developed by its own attorney during cross-examination of BPA's witnesses. Tr. 35.

Given the competitive situation currently facing BPA and echoed in the testimony and briefs of literally every other party submitting testimony to this proceeding save CBI, BPA's ability to raise rates to "stabilize revenues" as urged by CBI would be contrary to sound business principles in that it would serve to imperil BPA's ability to meet its long-term obligations to effect Treasury repayment. See generally Moorman, E-BPA-13; Waddington, E-DS-01, O'Meara, E-PP-01, PPC Brief, B-PP-01. The use of section 4(h)(10)(C) credits, both through the reduction of BPA's current FY Treasury payment obligation, and the increase of BPA's financial reserves to meet future repayment obligations, is fully consistent with the concept of "sound business principles." It also comports with the legal requirement of section 4(h)(10)(C) that BPA ratepayers bear only the appropriate share of certain fish mitigation costs.

Moreover, in that the added amount of reserves contributed by the respective FY 1995 and FY 1996 4(h)(10)(C) credits increases the probability of timely and full Treasury repayment for the FY 1995 rate period and for BPA's obligations in FY 1996 , use of the

4(h)(10)(C) credit aids BPA in fulfilling its statutory obligation to assure Treasury repayment over a reasonable number of years. See Tr. 37.

***Decision***

*BPA's use of the 4(h)(10)(C) credits, particularly in the current competitive environment that limits BPA's ability to secure additional revenues from continued rate increases, fully comports with sound business principles, and represents a prudent and reasonable approach to meeting BPA's cost recovery obligations. The use of the 4(h)(10)(C) credits serves to enhance BPA's ability to meet both its current and future Treasury repayment obligations, and thus fully comports with the statutory directive that rates be established to assure repayment of the Federal investment over a reasonable period of years.*

***Issue***

*Whether BPA ignored the law in relying on an understanding with the executive branch of government by including in the Initial Proposal $120 million in credits against its payments due to the United States Treasury.*

**Parties' Positions**

CBI argues that BPA ignored the law by including in the initial proposal a credit for $120.6 million against its payments due to the Treasury. CBI Br., B-CB-01, 19. CBI suggests that BPA has improperly relied on a "deal" with the Office of Management and Budget for a credit against BPA's Treasury payment. Id. CBI argues that the Executive Branch has no power to amend the law or to permit a Federal agency to disobey the law.

**BPA's Position**

BPA is claiming a credit against its Treasury payment under section 4(h)(10)(C) of the Northwest Power Act. Therefore, it is following the law by including the credit in the Initial Proposal. DeWolf et al., E-BPA-16, 2, 5-6. The agreement with the Administration merely reflects the Administration's agreement with BPA's interpretation and implementation of applicable law.

**Evaluation of Positions**

CBI argues that BPA's inclusion of the credit based on an agreement with the Office of Management and Budget is inappropriate in that it ignores BPA's responsibility under the law to repay Treasury. CBI misunderstands BPA's testimony and the cost-sharing arrangement between BPA and the Administration. Section 4(h)(10)(A) of the Northwest Power Act directs the Administrator to use the Bonneville Fund in the United States Treasury "to protect, mitigate, and enhance fish and wildlife to the extent affected by the

development and operation of any hydroelectric project of the Columbia River and its tributaries." 16 U.S.C. § 839b(h)(10)(A) (1988). Section 4(h)(10)(C) provides as follows:

> The amounts expended by the Administrator for each activity pursuant to this subsection shall be allocated as appropriate by the Administrator, in consultation with the Corps of Engineers and the Water and Power Resources Service, among the various hydroelectric projects of the Federal Columbia River Power System. Amounts so allocated shall be allocated to the various project purposes in accordance with existing accounting procedures for the Federal Columbia River Power System.

16 U.S.C. § 839b(h)(10)(C) (1988).

Under this subsection, the Administrator makes two allocations of the costs of measures taken to protect fish and wildlife. He allocates the costs first, among the various Federal hydroelectric projects, and second, among the various project purposes. The projects for which BPA is the power marketing agent are generally multipurpose projects established to serve a variety of uses, including power production, flood control, navigation, irrigation, and others. DeWolf et al., E-BPA-16, 5. Consumers of electric power, however, are responsible only for the costs of measures that compensate for the effects of power production. Section 4(h)(8)(B) of the Northwest Power Act provides that "[c]onsumers of electric power shall bear the cost of measures designed to deal with adverse impacts caused by the development and operation of electric power facilities and programs only." 16 U.S.C. § 839b(h)(8)(B) (1988) (emphasis added).

Thus, under section 4(h)(10)(A), BPA initially funds measures to mitigate fish and wildlife as affected generally by the operation of Federal hydroelectric projects. The agency then sets rates to recover only those costs allocated to power production at the various projects. BPA's initial funding of all the costs avoids the need for funding through the annual appropriations process on an individual project basis. DeWolf et al., E-BPA-16, 5. So that BPA's ratepayers do not carry an unfair burden, however, Congress gave BPA the authority to recoup the mitigation costs it incurs on behalf of non-power project purposes. Id. These costs are non-reimbursable; that is, BPA is not obligated to reimburse the Treasury for them. Instead, they are regarded as having been applied toward other project costs repayable to the Treasury for which BPA is responsible. The Interior Committee Report on the Northwest Power Act addressed this issue as follows:

> The allocation of particular costs to individual projects and among different project purposes, as is required by existing law, is preserved in this subparagraph to avoid establishing any precedent of a different allocation result. Thus, power, irrigation, navigation, recreation and other project purposes will continue to bear only their established shares of the total costs attributable to the protection and mitigation measures. All expenditures by BPA are to be made on a reimbursable basis vis-a-vis other project purposes, although BPA will have the flexibility to treat

> expenditures in excess of its allocated share as being payments for other project costs for which BPA is responsible under existing law.

H.R. Rep. No. 976, 96th Cong., 2d Sess., pt. 2, at 45 (1980).

Thus, BPA receives a credit against its Treasury payment for expenditures attributable to other project purposes and electric power consumers ultimately bear only that portion of the costs attributable to power production. DeWolf, et al., E-BPA-16, 6.

Therefore, by including the credit in its initial proposal, BPA has followed the mandate of the Northwest Power Act. In its testimony BPA quoted the testimony of Alice Rivlin, Director of the Office of Management and Budget, before the Subcommittee on Energy and Water of the Senate Appropriations Committee. Director Rivlin testified that the Administration had agreed to allow BPA credits on its Treasury payments of approximately $120 million for the next 2 years. Id., at 2-4. CBI suggests that BPA's reliance on this testimony is misplaced, because Director Rivlin cannot agree that BPA can ignore the law. CBI's Brief, B-CB-01, 19-20. Director Rivlin testified, however, that the credits were being allowed "under section 4(h)(10)(C) of the Northwest Power Act." DeWolf, et al., E-BPA-16, 3. Her testimony simply indicates the Administration's assent to BPA's interpretation of its authorities under the Northwest Power Act. Far from demonstrating the Administration's attempt to circumvent the law, the testimony relies on and effectuates the law's directives. The cost-sharing arrangement implements these directives.

Moreover, the figures cited by Director Rivlin do not represent an arbitrary agreement between BPA and the Administration, as CBI implies. See CBI's Brief, B-CB-01, 19-20. To determine the amount of the credit, BPA used the existing allocation methodology established by the Corps of Engineers, Bureau of Reclamation, and Federal Energy Regulatory Commission. This methodology produced an allocation under which 73 percent of mitigation costs were allocated to power uses and 27 percent to non-power uses. DeWolf, et al., E-BPA-16, 6. The cost-sharing arrangement with the Administration specified that each year's credit would be based on that year's expenses and capital outlays of BPA's Fish and Wildlife program (exclusive of wildlife costs) and the annual interest income on BPA's cash balances that BPA lost as a result of the expenditures. Id. Pursuant to the existing methodology, the credit equals 27 percent of these costs. Id. Thus, the size of the credit was not based on a "deal" with the Administration.

Finally, CBI's assertion that the credit consists of "undefined and indefinite deferrals on Treasury repayment obligations" is incorrect. CBI's Brief, B-CB-01, 21. The credit is specific, is taken pursuant to law, and does not constitute a deferral of repayment obligations. Instead, as shown above, it represents an amount that BPA is not obligated to transfer as cash to the Treasury. Thus, contrary to CBI's assertion, it is not a "one-time" credit. CBI's Brief, B-CB-01, 20. The credit is embodied in the Northwest Power Act, and Director Rivlin indicated that BPA will receive "annual credits on a permanent basis

under section 4(h)(10)(C) of the Northwest Power Act" for its fish and wildlife expenses. DeWolf, et al., E-BPA-16, 3.

***Decision***

*BPA followed the directives of section 4(h)(10)(C) of the Northwest Power Act when it included a credit against its Treasury payments in the Initial Proposal. Therefore, the credit will be included in BPA's final rate proposal.*

### 2.1.2.5 Cost and Revenue Components

***Issue***

*Whether BPA's projected revenues from surcharged rates are adequate to recover its projected costs in FY 1996.*

**Parties' Positions**

CBI argues that projected revenues from BPA's proposed rates are not sufficient to cover BPA's costs over the FY 1996-1997 period. Bell, E-CB-01, 17; CBI's Br., B-CB-01, 17-18. CBI claims that BPA understates its projected costs for FY 1996 and overstates its projected revenues for FY 1995 and FY 1996, leading to a "revenue shortfall." Bell, E-CB-01, 17 CBI identified certain costs and revenue sources that CBI asserts lead to a "revenue shortfall" in FY 1996. Initially, CBI identified two cost components and three revenue components as responsible for "revenue shortfalls" totaling over $350 million. Id. at 5-8. In its brief, CBI identified only two revenue components. CBI's Brief, B-CB-01, 19.

On the cost side, CBI claims that "revenue shortfalls" are produced by: (1) an $80 million undistributed cost reduction; and (2) a $60 million reduction in BPA's annual cash payment to the U.S. Treasury resulting from recent fish cost mitigation. Bell, E-CB-01, 5-6; CBI's Brief, B-CB-01, 18-19.

On the revenue side, CBI originally claimed that the revisions to BPA's revenue forecast identified in BPA's initial proposal (estimated to reduce projected revenues contained in BPA's initial proposal for both current and proposed rates by about $55 million) produced a "revenue shortfall." Bell, E-CB-01, 5. CBI also identifies two additional revenue-related sources of "revenue shortfalls": (1) a $47 million revenue reduction due to additional loss of DSI and utility load in FY 1996 arising from recent agreements made between BPA and its customers that allow customers to reduce their load on BPA (waiver agreements), and (2) a $64 million reduction in nonfirm energy revenues resulting from the collapse in firm bulk power market prices over the last several months. Bell, E-CB-01, 6-8. In its brief, however, CBI acknowledged that BPA's preliminary estimate of revenue forecast revisions included the revenue effects associated with the waiver agreements, and CBI modified its initial position. In its brief, CBI identified two revenue

sources that it alleges contribute to a "revenue shortfall": (1) the waiver agreement, which CBI now claims reduces BPA's total revenue by $26 million, instead of $64 million; and (2) the recent changes in nonfirm markets, which CBI now claims reduces BPA's total revenues by $54 million instead of $64 million. CBI Br., B-CB-01, 17-18.

**BPA's Position**

CBI mischaracterizes BPA's planned cost cuts and Treasury credit as a "revenue shortfall." These cost items are not "shortfalls" but are actions that BPA is taking to improve cash flows. DeWolf, et al., E-BPA-22, at 2. The undistributed cost reduction is a planned *decrease* in previously established FY 1996 spending levels, which reduces BPA's total revenue requirement. Id. at 3. The section 4(h)(10)(C) credits allows BPA to recoup fish and wildlife expenditures incurred on behalf of non-power purposes at the FCRPS projects. In effect, the 4(h)(10)(C) credits increase revenue and thereby decrease the risks that BPA will not recover its costs. Id. at 4. The section 4(h)(10)(C) credits increase BPA's funds available for repayment in FYs 1995 and 1996. Id. at 5

CBI overstates the reduction in BPA's expected revenues in FY 1996 due to additional loss of DSI and utility load in FY 1996 and changes in nonfirm energy markets over the past few months. Metcalf, et al., WP-95-E-BPA-23, 3-4. Moreover, CBI focuses solely on increasing rates to bring revenues and costs into balance and ignores other means available to BPA to assure cost recovery. Id. In addition, regarding the alleged nonfirm energy "revenue shortfalls," CBI's conclusions reflect a short-term view based on recent market conditions. BPA's nonfirm revenue forecast, however, is based on conditions expected in FY 1996. Id. at 7-8.

**Evaluation of Positions**

CBI alleges that the 4 percent increase in BPA's 1995 rates (surcharged rates) produces "significant revenue shortfalls." Bell, E-CB-01, 1. A "revenue shortfall," CBI states, exists when BPA does not have enough money to cover its costs. Id.; CBI's Brief, WP-95-B-CB-01, 17. According to CBI, the settlement agreement entered into with most of the parties in this rate proceeding prohibits BPA from reconciling rate levels to cover costs and as such, CBI argues that the only practical option available to BPA in the event of a significant revenue shortfall is to renege on its financial obligations, in particular, repayment of the Federal investment. Id. at 3. The issues CBI raised regarding the settlement are discussed at section 4.2, infra. CBI admits that BPA may be able to reduce its FY 1996 revenue requirement but argues that the only way to accomplish this reduction is to defer obligations to later years and drain reserves in FY 1996. As such, CBI argues that actions to reduce FY 1996 revenue requirements exacerbate BPA's ability to recover costs in the ensuing 1996 rate proceeding. Id.

CBI's arguments are unsupported and without merit. In its initial proposal, BPA prepared a cost recovery demonstration using its proposed rates. See Revenue Requirement Study, E-BPA-10, 58-59; 62-67. The cost recovery demonstration shows that BPA expects to

recover its projected costs at the surcharged rates without deferring FY 1996 costs to future years. Id. In fact, projected cost cuts (undistributed reductions) are greater in FYs 1997-2000 than the $80 million undistributed reduction included in rates for FY 1996. Section 7(b)(2) Study Documentation, WP-95-E-BPA-12A, 133-137.

In testimony, CBI points to five areas where, CBI alleges, BPA either understated its projected costs or overstated its projected revenues. Id. at 5-8. These five areas include:

(1) a $55-million revenue forecast shortfall due to a combination of changes in purchase power assumptions, reduced storage balances entering FY 1996, reduced DSI sales (not including waiver adjustments), revisions in expected new long-term SP sales, changes in short-term seasonal spot markets, surplus capacity sales, and increased wheeling revenues;
(2) an $80 million undistributed (unidentified) cost reduction in BPA's revenue requirement;
(3) a $60 million credit in FY 1996 to help cover expected costs resulting from the National Marine Fisheries Service (NMFS) 1995 Biological Opinion, which in effect allows BPA to reduce its payments to Treasury;
(4) a $47 million reduction in revenues associated with additional loss of DSI and utility load in FY 1996 arising from recent agreements made between BPA and its customers that allow customers to reduce their load on BPA (waiver agreements); and
(5) a $64 million reduction in nonfirm energy revenues resulting from the recent collapse in firm bulk power market prices.

In its brief, however, CBI mentions only four areas and changes the amounts associated with each of these areas. CBI's Brief, B-CB-01, 17-19. CBI argues that these four areas result in BPA's expected FY 1996 costs exceeding expected FY 1996 revenues by over $350 million. CBI's Brief, B-CB-01, 19 The four "revenue shortfall" areas identified by CBI include: (1) an $80 million undistributed cost reduction; (2) a $60 million reduction in BPA's annual cash payment to the U.S. Treasury resulting from recent fish cost mitigation credits; (3) a $26 million reduction associated with additional loss of DSI and utility load in FY 1996 arising from recent agreements made between BPA and its customers that allow customers to reduce their load on BPA's (waiver agreements); and (4) a $54 million reduction in nonfirm energy revenues resulting from the recent collapse in firm bulk power market prices. Bell, E-CB-01, 6-8; CBI's Brief, B-CB-01, 17-18. Each of these four areas is discussed below:

**1. Undistributed Cost Reductions**

CBI claims that BPA's undistributed cost reductions really are nothing more than a discrepancy between BPA's revenue requirement and its revenue forecast. Bell, E-CB-01, 5; CBI's Brief, B-CB-01, 18. CBI concludes that because BPA was not able to specify exactly where the cost cuts would be made, the undistributed cost reductions are disguised "revenue shortfalls." CBI's Brief, B-CB-01, 18. These assertions, and the

general issue of reliance on the Administrator's direction to cut costs, are thoroughly addressed in Section 2.1.2.1. For purposes here it is sufficient to observe, as BPA witnesses explained that the undistributed cost reductions are, in fact, a reduction in BPA's revenue requirement. DeWolf, et al., E-BPA-22, 3. The undistributed cost reductions are a planned *decrease* in previously established FY 1996 spending levels. As BPA witnesses explained, the reason BPA was not able to identify the precise program cuts was due to the timing of the initial proposal and the budget process. Id. When BPA's initial proposal was published, BPA was engaged in a budget process to determine which program components would be reduced, and by how much, to achieve an overall cost reduction of $80 million. The timing of BPA's budget process is such that allocation of the $80 million cost reduction had not been decided at the time BPA's initial proposal was published. Id. As discussed in section 2.1 supra, program and budget issues are decisions made by the Administrator outside the rate case process. The allocation of cost cuts constitute fundamental management decisions as to how best to conduct BPA's affairs in a sound and businesslike manner. The fact that the Administrator had not yet decided on the precise cost cuts at the time BPA published its initial rate proposal does not mean that the decisions would not be made. See also discussion of reliance on Administrator's cost cuts in FY 1996, supra. As BPA witnesses testified, the specific cost reductions have been identified and are included in BPA's final cost projections for the test period. Final Revenue Requirement Study, WP-95-FS-10, 15.

Undistributed cost reductions do not constitute evidence that BPA will experience a significant revenue shortfall that will undermine cost recovery. In fact, the undistributed cost reductions improve cash flows and the likelihood of cost recovery. DeWolf, et al., E-BPA-22, 2.

**2. Section 4(h)(10)(C) Revenue Credits**

Issues concerning BPA's section 4(h)(10)(C) credits are thoroughly addressed in section 2.1.2.4.. The evaluation here briefly recasts part of that discussion. CBI asserts that the $60 million Federal payment in FY 1996 to help cover expected costs resulting from the National Marine Fisheries Services (NMFS) 1995 Biological Opinion (section 4(h)(10)(C) revenue credit) is in effect another "revenue shortfall." Bell, E-CB-01, 6; CBI Br., B-CB-01, 19. CBI alleges that BPA has resorted to 'accounting legerdemain' to apply $120 million from 2 years' worth of an OMB 'deal' regarding BPA costs to single year reserves in FY 1996. CBI's Brief, B-CB-01, 19. BPA's reliance on the section 4(h)(10)(C) revenue credit for FY 1996 is discussed in section 2.1.2.4, supra. CBI fundamentally mischaracterizes the 4(h)(10)(C) credits as a reduction to projected revenues, when in fact the credits increase BPA's revenues and reduce the risks that costs will not be recovered. DeWolf, et al., E-BPA-22, 5-6.

As BPA witnesses testified, the 4(h)(10)(C) revenue credits have the effect of *increasing* the funds available for repayment in FYs 1995-96, rather than reflecting a shortfall in available funds. Id., 5. In response to a data request by BPA, CBI belatedly conceded

that the net effect of the OMB payment in FY 1996 is a $60 million reduction in BPA's Treasury repayment obligations. Id., Attachment C.

As BPA witnesses explained, BPA is implementing a fish mitigation cost-sharing arrangement with the Administration. DeWolf, et al., E-BPA-16, 2-3; see also Revenue Requirement Documentation, Vol. 1, WP-95-E-BPA-11A, 307-317. The arrangement between BPA and the Administration is embodied in testimony by Alice Rivlin, Director of OMB, before the Subcommittee on Energy and Water, Senate Appropriations Committee, on March 15, 1995. DeWolf, et al., E-BPA-16, 2-3. The arrangement calls for some relief to BPA from escalating costs due to salmon recovery initiatives, including the 1995 Biological Opinion recently issued by NMFS. Id., 3. The relief takes two forms, one of which is annual credits beginning in FY 1995 against BPA's cash transfers to Treasury under Section 4(h)(10)(C) of the Northwest Power Act. Id.

Section 4(h)(10)(C) of the Act provides that the Administrator's fish and wildlife expenditures shall be allocated by the Administrator among the projects of the FCRPS and then, in turn, allocated among the multiple purposes of the individual projects. The portion of BPA's fish and wildlife expenditures allocated to non-power purposes is regarded as having been applied toward other project costs repayable to the U.S. Treasury for which BPA is responsible. Consequently, electric power consumers only bear the costs of the power production portion of the fish and wildlife measures. BPA receives the credits by reducing its annual cash transfers to the U.S. Treasury by an amount equal to the sum of the expenditures in that year allocated to non-power purposes. DeWolf et al., E-BPA-22, 5. Projected credits total $56.3 million and $64.3 million in FYs 1995 and 1996, respectively. The credits are treated as revenues in financial statements and in this rate proposal. DeWolf, et al., E-BPA-16, 5-11. Each year's recoupment is to be calculated from that year's expense and capital outlays of BPA's Fish and Wildlife program (exclusive of wildlife costs). Id.; see also, DeWolf, et al., E-BPA-22, 5.

Contrary to CBI's allegations, the section 4(h)(10)(C) credits increase BPA's funds available for repayment in FYs 1995 and 1996.

### 3. DSI and Utility Load Reductions

Initially, CBI's witness alleged that the loss of DSI and utility load associated with the waiver agreements would result in a $47 million "revenue shortfall." Bell, E-CB-01, 8. CBI claimed that its estimate of the revenue loss was based on the difference between the revenue BPA would have received under the Priority Firm (PF) rate and the DSI rates and the revenue from reselling that power in the nonfirm market combined with the reduced purchase power costs. According to CBI, the waivers would result in a net revenue loss of 12 mills/kWh. Id. When questioned about the assumptions and the source of the numbers used to derive this figure, however, CBI failed to provide any explanation or documentation in support of its net loss figure. See Metcalf, et. al., WP-95-E-BPA-23, 3-5. Apparently the 12 mills/kWh net loss figure is merely an undocumented assumption or opinion. Id. In its brief, CBI revised its original calculation,

again without any support or documentation. CBI now asserts that the amount of "revenue shortfall" is only $26 million instead of $47 million. CBI's Brief, B-CB-01, 17.

In any case, CBI's entire argument misses the point. In response to CBI's questions on BPA's initial load forecast, BPA corrected its load forecast to reflect the recent load waiver agreements between BPA and its utility and DSI customers. Answer of BPA In Opposition to CBI's Motion to Strike Errata, WP-95-M-14, 10-14. BPA's revenue forecast is based on this load forecast. Revenue Forecast Study, E-BPA-11, 5. To the extent that loads now reflect the utility and DSI waiver agreements. BPA's final revenue forecast incorporates the effects associated with the waiver agreements with utilities and DSIs. BPA's projected final revenues reflect the waiver agreements.

As CBI finally states in its brief, the issue is not by how much revenues will be reduced, but how BPA will respond to the change in expected revenues. CBI's Brief, B-CB-01, 17. CBI claims that BPA has not indicated on the record how it will respond to the reduction in expected revenues in FY 1996. Id. CBI again is mistaken. BPA witnesses testified that BPA's initial revenue projection would be adjusted to reflect, in part, a reduction in revenues due to reduced loads. Wedlund, et al., E-BPA-17, 5. BPA witnesses also testified that this revenue reduction would result in reduced planned net revenue for risk rather than an additional increase in rates. DeWolf et al., E-BPA-16, 23. BPA's witnesses also provided a general rule of thumb for determining the effect of reduced revenues on Treasury repayment probability. Id.

Apparently CBI believes that BPA's only realistic option for responding to a $26 million revenue reduction in its total projected revenues of $2,487 million is to further increase its rates above the 4 percent increase initially proposed. Id., at 22. CBI's conclusion is shortsighted and ignores market realities.

As the marketing agent for Federal hydropower in the Pacific Northwest, BPA has a unique responsibility to meet the needs of its customers and the Government. BPA is obligated to set its rates to repay the Federal investment in the FCRPS over a reasonable number of years and meet its other costs. BPA's rates must be established "in accordance with sound business principles." 16 U.S.C. § 839e(a)(1). Sound business principles means, among other things, that BPA's rates must be competitive to sustain revenues and assure continuing Treasury repayment over time. PPC Br., WP-95-B-PP-01, 2. As evidenced in this proceeding, BPA's rates with a 4-percent surcharge are acceptable for a limited 1-year period but may be higher than the prices in today's market will sustain. As BPA witness Moorman, testified, when BPA prepared its initial proposal, BPA's customers had been receiving offers from alternative suppliers at prices ranging from 26 to 32 mill/kWh. Moorman, E-BPA-13, 11. By the end of June, the market price had dropped into the low 20 mills/kWh range. Moorman, Tr. 21-22.

In addition, BPA's customers submitted testimony that the 4 percent surcharged rates are above the price of power on the market today for deliveries beginning October 1995, and beyond. Waddington, WP-95-E-DS-01, 2-3; O'Meara, WP-95-E-PP-01, 2; PPC Br.,

B-PP-01, 2-3; Saven, WP-95-E-NI-01, 3. As the PPC noted, increasing rates above 4 percent for the 1-year period sends a message that BPA rates will not be competitive. PPC cautions appropriately that such an increase may cause customers to lose confidence in BPA and look elsewhere for power. PPC Br., B-PP-01, 3.. Even CBI recognizes the competitive nature of the market and in fact suggests that the prices in today's market are around 26 mills/kWh. See Bell, E-CB-01, 29, fn 6 (stating that if spot prices are in the range of 10-14 mills/kWh, then prices should be reduced by 19 mills/kWh; using this math, CBI apparently believes that market prices are in the range of 29 to 33 mills/kWh. CBI suggests that because of recent changes in market conditions, prices should be reduced about 3 mills/kWh, which produces a range of 26 to 29 mills/kWh.)

As PPC correctly notes, BPA has a range of alternatives for managing its expected costs to match its expected revenues. PPC Br., B-PP-01, 4. The decision on the level of BPA's rates requires balancing a number of factors and ultimately making an informed judgment call within a broad range of alternatives. As evidenced in this proceeding, BPA has a strong and legitimate interest in pursuing all reasonable alternatives to keep the magnitude of the rate increase to 4 percent.

**4. Recent Changes In The Nonfirm Energy Markets**

CBI points to the recent "collapse in firm bulk market prices" and assumes that this "collapse" will reduce BPA nonfirm revenues by $54 million. Bell, E-CB-01, 9-10. CBI's witness acknowledged that the bulk power market was extremely competitive, with prices approaching the short-run operating costs of efficient plants. Bell, E-CB-01, 9. CBI further recognized that some of the factors that are driving bulk power prices include low natural gas prices, near normal Northwest hydro flows, and *above normal* hydro flows in California. Id., (emphasis added) Based on these recent conditions, CBI alleges that BPA's projections of nonfirm energy revenues for the remainder of FY 1995 and all of FY 1996 are probably too high. Id. CBI apparently assumes, without any support, that the recent market conditions will continue throughout FY 1996. Id, at 10; CBI's Brief, B-CB-01, 18.

The critical factor in assessing the accuracy of CBI's alleged nonfirm energy "revenue shortfall" is CBI's assumption that nonfirm energy prices for the remainder of FY 1995 and all of FY 1996 will be 3 mills/kWh lower than the prices BPA projected in the initial proposal. Bell, CB-01, 10. CBI, however, did not cite any analysis or documentation to support the 3 mills/kWh number. The assumed 3 mills/kWh reduction in nonfirm energy prices, and therefore the $64 million (or $53.4 million) "revenue shortfall" identified by CBI, appears to be merely an assumption or opinion based on undocumented observations and personal conversations with unidentified analysts. Metcalf, et al., E-BPA-23, 7. In a footnote, CBI cites spot prices in the range of 10 to 14 mills/kWh, apparently to support its range of nonfirm energy prices. Bell, E-CB-01, 26, fn. 6. Yet BPA's forecasted average nonfirm energy prices for FY 1996 of 14 mills/kWh are within the range cited by CBI. Revenue Forecast Study, E-BPA-11, 27-28.

BPA agrees that the bulk power market is competitive and that prices in this market have dropped to very low levels in the past month. Id. The recent drop in fuel prices and surplus conditions in California are depressing the price that BPA currently is able to obtain for nonfirm energy sales. BPA witnesses testified that the change in nonfirm energy prices over the last several months would be included in BPA's final revenue forecast if not already reflected. For the final proposal, BPA will include actual revenues through at least May 1995 in its FY 1995 revenue forecast.

BPA disagrees, however, that the recent market conditions necessarily will continue through FY 1996. Although CBI discusses current natural gas prices and abnormally high hydro conditions in California, CBI has not provided any evidence that these conditions will continue in FY 1996. CBI has not offered any evidence concerning gas prices in FY 1996, nor any evidence relating to expected California hydro conditions in FY 1996. For the FY 1996 revenue forecast, the relevant issue is not what current conditions are, but whether these conditions will continue in the future. Metcalf, et al., E-BPA-23, 8. Although CBI recognizes that conditions affecting the demand for nonfirm energy can affect the price for this energy, CBI selectively focuses on one condition affecting the demand for nonfirm energy, above normal hydro conditions in California, and selectively ignores other conditions that effect the demand for nonfirm energy. Id. On closer examination, it appears that CBI's nonfirm "revenue shortfalls" are in effect a phantom shortfall and reflect a basic lack of knowledge about BPA's revenue forecast of nonfirm energy.

CBI believes that if nonfirm energy prices are in the range of 10-14 mills/kWh then BPA's revenues would be reduced even further. CBI asserts that nonfirm energy prices in the range of 10-14 mills/kWh would result in a "revenue shortfall" of 19 mills/kWh. Bell, E-CB-01, 29, fn. 6. Apparently, CBI believes that BPA is forecasting nonfirm energy prices during the rate period in the range of 29-32 mills/kWh. It appears that CBI failed to review or consider BPA's projected nonfirm energy prices for the rate period when it reached this conclusion. In fact, it was only after BPA filed rebuttal testimony that CBI even asked for information on BPA's nonfirm energy revenue forecast. Bell, TR 86-88. Although CBI claims it reviewed BPA's initial proposal, a cursory review and simple calculation would have revealed that BPA's average expected price for nonfirm energy during FY 1996 is 14 mills/kWh. Revenue Forecast Study, E-BPA-11, 27-28. Even a quick review of BPA's expected nonfirm energy rates in FY 1996 would show that the highest expected price for sales of nonfirm energy was 16.5 mills/kWh for about 13 aMW expected to be sold to the PSW in February, 1996. Revenue Forecast Documentation, E-BPA-11A, 17. BPA projected that the majority of its nonfirm energy sales would be made at prices around 14 mills/kWh or lower. Id.

***Decision***

*The surcharged rates will recover BPA's 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 costs and expenses incurred by the Administrator pursuant to law. BPA has demonstrated that revenues from surcharged rates are adequate to recover its projected costs in any FY 1996. The cost recovery demonstration shows that BPA expects to recover its projected costs at the surcharged rates without deferring any costs in FY 1996 to future years. BPA's forecasted costs and revenue sources for the test period are reasonable.*

# 3.0 RATE DESIGN

## 3.1 Introduction

On February 14, 1995, BPA published a preliminary rate proposal in the Federal Register with substantial rate design changes, and noted that in light of competitive forces its initial rate proposal for fiscal years (FY) 1996 and 1997 should include a 5-year rate as well as a 2-year rate. Proposed Wholesale Power Rate Adjustment, Public Hearing, and Opportunities for Public Review and Comment, 60 Fed. Reg. 8496 (1995). In the Federal Register notice BPA stated that it required additional time to develop the proposal. Moorman, WP-95-E-BPA-13, 15-16. In addition to the time to develop the proposal, BPA expected to conduct discussions with its customers and third parties to evaluate and respond to the proposed new rate designs. At the same time, numerous parties expressed the need to evaluate the proposed rates in combination with BPA's new power sales contracts then under negotiation. Id. at 16. As a result of these events, BPA and most parties to the 1995 rate proceeding agreed that BPA should propose a 4 percent surcharge to BPA's existing adjustable rates for the 1-year period. Id. at 16-17.

BPA's initial 1995 rate proposal, therefore, proposed a 4 percent surcharge to each component of its adjustable rates for a 1-year period, October 1, 1995, through September 30, 1996, including extending the Variable Industrial (VI) rate for 3 months. Id. at 17. The existing VI rate (VI-91) expires June 30, 1996. Id. The rate components adjusted are those rate components that are normally revised to reflect changes in BPA's costs and loads, and those rates that are tied to such rate components. Id. The initial 1995 proposal did not include any rate design changes other than to propose two new rates: the Southern Intertie Annual Cost rate (AC-95) and the rates for the Amended and Integrated Pacific Northwest Coordination Agreement (PNCA). Id., Attachment B, 3. Even though BPA's initial 1995 rate proposal contemplated no rate design changes, parties to the 1995 rate proceeding were not precluded from proposing rate design changes in the rate proceeding. Accordingly, one party, CBI, did propose some rate design changes. These included a proposal to eliminate the Irrigation Discount, discussed at section 3.2.1. infra; and a proposal to modify the eligibility requirements of the Low Density Discount (LDD) and to eliminate the LDD for irrigation loads, discussed at section 3.2.2. infra.

For the proposed 1995 rates, BPA did not perform a Cost of Service Analysis using its projected FY 1996 revenue requirement. Revenue Forecast Study, WP-95-E-BPA-11, 13. Instead, BPA relied on the cost allocations used to develop its 1993 rates. BPA believes that the cost recovery relationships among the different customer classes established in its 1993 rates are still valid, and that performing a cost allocation using the projected 1996 revenue requirement would not substantially change these cost recovery relationships. The historical 1993 test period used to establish the relationship among customers is the basis for developing the 1995 rate proposals. Id.

Even though BPA did not perform a Cost of Service Analysis to establish its 1995 rates, it did compare generation cost relationships among the power rate customer classes. Metcalf, et al., WP-95-E-BPA-17, 14. A comparison of the projected FY 1996 generation costs and the generation costs projected for the 1993 rate case indicated that the major expected generation cost increases are associated with revenue requirement components that are recovered by all customer classes. Federal Base System direct resource costs, which are allocated to Priority Firm Power (PF) customers, remain close to the level projected for the 1993 rates. Residential Exchange costs and New Resource costs, however, are projected to be lower in FY 1996 than to the projections made in the 1993 rate case. Id.

As part of its comparison of generation costs, BPA also determined that the relative percentage of expected revenues from the rate pools associated with BPA's different customer classes would not change for FY 1996. Id. The Northwest Power Act describes three rate pools: a 7(b) rate pool consisting of sales to Priority Firm Power customers; a 7(c) rate pool consisting of sales to DSIs; and a 7(f) rate pool consisting of all other sales. 16 U.S.C. §§ 839e(b), (c) and (f). Since implementation of the 7(c)(2) rate directives in 1985, BPA has, for all practical purposes, had only two rate pools: the 7(b) rate pool and all other rate pools. Moreover, except for a *de minimus* amount of 7(f) load used to establish the New Resources (NR) rate, none of the non-7(b) rates are based on allocated costs. Instead, most of the non-7(b) rates are tied to the Priority Firm Power (PF) rate. The costs allocated to the non-7(b) rate pools, to a large extent, are commingled with the PF rate as a result of either the rates being linked to the PF rate or some other factor, such as BPA's Average System Cost (BASC) or market prices. Metcalf, et. al., E-BPA-17, 14.

The Northwest Power Act also directs BPA to equitably allocate the costs of the Federal transmission system between Federal and non-Federal power using the system in setting its transmission rates. 16 U.S.C. § 839e(a)(2)(C). By applying a 4 percent surcharge to both the 1993 power and transmission rates, BPA continued to rely on the equitable allocation analysis performed in the 1993 rate case. Metcalf, et. al., E-BPA-17, at 16. Since the 1993 rate case analysis, BPA determined that few, if any, changes occurred that would significantly affect the relative level of a rate increase needed between the transmission (wheeling) and power rates. There have been no significant changes in the relative segmentation of costs. BPA addressed changes in the relative size of power and wheeling loads by applying the surcharged rates to the billing determinants. Id. A problem with the size of power and wheeling loads would occur only if the relationship between the billing determinants and the cost allocators had changed. The relationship between the billing determinants and the coincidental peak allocation factors is contained in the coincidence factors. The 1993 coincidence factors were developed using load data from July 1988, through June 1992. BPA determined that updating the coincidence factors with an additional 2 years of historical data would not have resulted in substantial changes, and, therefore, did not update the coincidence factors for the 1995 rate case. Id. at 16-17.

### 3.2 Power Rates

BPA's wholesale power rates were increased by a proposed 4 percent surcharge to each component of its adjustable rates. Revenue Forecast Study, WP-95-E-BPA-11, 12-13. The demand and energy charges in the PF-95 rate, Industrial Firm Power (IP-95) rate, VI-95 rates, and NR-95 rate are increased by 4 percent. Also, the Irrigation Discount in the PF-95 and NR-95 rate schedules, and the First Quartile Discount in the IP-95 and VI-95 rate schedules are increased by 4 percent. Since the Energy Return Surcharge in the PF and NR rate schedule is based on changes in the PF demand charge, the surcharge was adjusted to reflect the change in the PF-95 demand charge. Id. Since the 1995 rates are 1-year rates, the Interim Rate Adjustment and Energy Tax Adjustment that appeared in the 1993 rate schedules do not appear in the 1995 rate schedules. Id.

The current percentages for the Low Density Discount and the Availability Charge remain unchanged. Any change to these rate adjustments could results in an overall rate increase greater than 4 percent to customers who are subject to these charges or discounts. 60 Fed. Reg. 21132, 21,135 (May 1, 1995). The Unauthorized Increase charge is maintained at its current level, 100 mills/kWh. The Unauthorized Increase charge is a penalty charge to deter customers from taking more power than the amounts to which they are contractually entitled. Id.

BPA has some long-term contract rates that are tied to changes in BPA's PF rate or BPA's Average System Cost (BASC). Id. BASC, a component of the NF Rate Cap, is also increased 4 percent. Revenue Forecast Study, E-BPA-11, at 13 Consequently, rates tied to BPA's PF rate or BASC also are increased 4 percent. Id.

Although the price BPA can obtain for sales under the Emergency Capacity (CE-95) and Nonfirm Energy (NF-95) rate schedules is based on market conditions, some of the components in these rate schedules normally are adjusted to reflect changes in loads and costs. Since the price BPA can obtain from these rates is based on market conditions, these rate schedules contain caps or ceilings rather than fixed rates. The CE rate cap and the Intertie Charge are increased by 4 percent. Id. Similarly in the NF-95 rate, the Intertie charge and the NF ceiling are increased by 4 percent. Id. The average cost of nonfirm energy, which is normally adjusted to reflect changes in BPA's costs and loads, is increased by 4 percent. The average cost of nonfirm energy triggers the Intertie adder charge. Id. The NF Contract rate also is increased by 4 percent. Id.

The Reserve Power (RP-95), Share-the-Savings (SS-95), and Power Shortage (PS-95) rates remain unchanged for the 1-year rate period. These rates normally are not adjusted to reflect changes in BPA's costs. Id.

BPA proposed to extend the Variable Industrial Power Rate (VI rate) for 3 months, through September 30, 1996. No party opposed the extension proposal. The VI rate has been in effect since 1986, and is currently due to expire on June 30, 1996. BPA's projections of aluminum prices indicate that the VI rate will be on the plateau during the

entire 3-month extension, meaning that the VI rate will equal the Industrial Firm Power (IP) rate. Therefore, the extension of the VI rate should have no effect on BPA's loads or revenues. Moreover, extending the VI rate until September 30 makes the term of the VI rate consistent with the terms of the other rates in BPA's rate proposal.

### 3.2.1 Irrigation Discount

***Issue***

*Whether BPA should eliminate the Irrigation Discount in the PF-95 and NR-95 rate schedules.*

**Parties' Positions**

CBI argues that there are hundreds of millions of dollars per year in indirect and direct subsidies by regional ratepayers and U.S. taxpayers to irrigation customers in the Pacific Northwest. CBI Br., B-CB-01, 22. CBI claims that the Irrigation Discount is a discretionary subsidy that initially was established as a temporary subsidy and has long-since outlived its usefulness. Id. CBI alleges that OMB provided $120 million to BPA to assist in paying for incremental salmon recovery costs which should be paid by irrigation customers. Id. CBI proposes that the Irrigation Discount be eliminated. Id.

Northwest Irrigation Utilities (NIU) argue that given the lack of comprehensive rate design review in the 1995 rate case, BPA should not adopt piecemeal rate design changes that may preclude giving irrigation utilities the opportunity to propose offsetting rate design changes. NIU Br., B-NI-01, 4. NIU argues that the alleged subsidy programs identified by NIU are irrelevant to this proceeding. Id. at 6. NIU argues that CBI's arguments are unsupported. Id. at 7-8. NIU proposes continuing the Irrigation Discount.

The PPC argues that its understanding of the Settlement Agreement was that issues such as rate design would not be considered. PPC's Br., B-PP-01, 5. PPC argues that the Irrigation Discount should be retained in order to be consistent with the Settlement Agreement. Id.

**BPA's Position**

The Irrigation Discount is an adjustment under BPA's PF and NR rate schedules. The discount is available to qualifying irrigation load during the months of April through October. Participating utilities are required to pass the discount through, in its entirety, to qualifying irrigation end-users. BPA proposed to continue the Irrigation Discount for the next 1-year rate period. See Revenue Forecast Study, E-BPA-11. Elimination of the Irrigation Discount in this rate period, together with the proposed rate increase, would result in disproportionate impacts on one customer class in the absence of a more thorough review of rate design. Moorman, E-BPA-21. BPA also notes that the alleged subsidies identified by CBI do not require elimination of the discount and OMB's

payments to BPA for fish and wildlife mitigation do not constitute an irrigation subsidy. Id., at 7-8.

**Evaluation of Positions**

CBI argues that it has identified hundreds of millions of dollars per year in indirect and direct subsidies by regional ratepayers and U.S. taxpayers to irrigation customers in the Pacific Northwest. CBI Br.. B-CB-01, 22. While CBI cited a number of non-discretionary "subsidies" to irrigation customers, CBI did not recommend specific action in BPA's rate case regarding such items or regarding funds provided by the Federal government for 1995 Biological Opinion costs. Moorman, E-BPA-21, 7. Also, as noted by NIU, agriculture programs administered by other Federal agencies are beyond the scope of this case. Saven, WP-95-E-NI-01, 12. While CBI has identified what it characterizes as "subsidies" which make the Irrigation Discount unnecessary, the existence of such alleged subsidies does not mean that the Irrigation Discount should be eliminated. Nearly all of the alleged subsidies identified by CBI already were in existence when BPA developed the Irrigation Discount. Moorman, E-BPA-21, 7. Despite these circumstances, however, BPA established the Irrigation Discount. See 1995 Administrator's Record of Decision, WP-85-A-02.

Along the same line, CBI argues that OMB specifically bestowed $120 million on BPA to assist in paying for incremental salmon recovery costs which should be paid by irrigation customers. CBI Br., B-CB-01, 22. These funds, however, do not constitute an irrigation subsidy. These payments are necessary because many of BPA's mitigation costs address impacts of entire hydro projects that have multiple purposes such as navigation, flood control and irrigation in addition to power production. Moorman, E-BPA-21, 8. Under section 4(h)(10)(C) of the Northwest Power Act, when BPA funds a mitigation measure for a hydro project and that measure mitigates for non-power purposes as well as power purposes, those responsible for the non-power share of mitigation owe BPA for the non-power share of that measure. Generally, the costs of mitigation for navigation, flood control and irrigation are non-reimbursable, meaning that they are covered by the Treasury and not reimbursed through power revenues. Id. Thus, the Treasury owes BPA for the non-power share of this mitigation. The Administration has agreed that BPA will recoup the amounts expended on behalf of non-power purposes by receiving a credit on its annual repayment to the Treasury. Id. This recoupment is not a subsidy to BPA or its customers, rather, it is essentially the Federal government repaying a loan from BPA's ratepayers. Id.

CBI argues that BPA can force irrigation utilities to absorb any increase from the elimination of the Irrigation Discount because most utilities are contractually bound to place their loads on BPA during the rate period. Bell, WP-95-E-CB-01, 23-24. In response, NIU argues that CBI's arguments are contrary to market realities and inconsistent with CBI's own testimony. NIU Br., B-NI-01, 7-8. NIU notes that CBI's testimony acknowledges that "BPA is now operating in a highly competitive marketplace, not a marketplace in which customers may be coerced into buying power from BPA

regardless of price." Saven, E-NI-01, 10, *citing* Bell, E-CB-01, 9. NIU notes that CBI improperly advocates increasing the price for power to irrigators regardless of whether the price bears any relationship to the market. NIU Br., B-NI-01, 7-8; Saven, E-NI-01, 11.

CBI also argues that even if BPA increased the PF rate, irrigation loads would not decrease because BPA previously had concluded that the loads were inelastic. Bell, E-CB-01, 23. In response, NIU notes that CBI fails to provide any evidence that irrigation demand is inelastic other than a conclusory statement from BPA's 1987 ROD. NIU Br., B-NI-01, 8. NIU also notes that even if this statement were based on evidence in the 1987 rate case, no such evidence has been provided in this case nor is there any reason to believe that BPA's statements in 1987 still apply under current market conditions. Id. NIU also notes that CBI has failed to identify whether the elasticities were short-term or long-term or whether they distinguish between end-use demand and demand at the wholesale level, nor does CBI account for any change in elasticity that might result from what CBI described as a "collapse" of wholesale power prices. Id., *citing* Bell, E-CB-01, 9.

There is, however, a more fundamental reason why the Irrigation Discount should not be eliminated in this proceeding. BPA is proposing an across-the-board surcharge with no changes in rate design. Moorman, E-BPA-21, 7. Removal of the discount in this period, together with the rate increase proposed by BPA, would result in the irrigation sector facing a disproportionately higher rate increase than other end-use consumers. Id.; Saven, E-NI-01, 2. Because no other rate design issues have been raised in this proceeding, BPA and other customers are concerned that piecemeal elimination of a single component of BPA's rate design, such as the Irrigation Discount, could result in impacts on a specific customer class that could be unwarranted and unnecessary relative to the results of a more comprehensive examination of BPA's rate design. Id. While BPA is not adopting CBI's proposal to eliminate the Irrigation Discount in this proceeding, BPA currently is examining rate design issues, including the Irrigation Discount, within the context of BPA's 1996 general rate case. In BPA's initial proposal for the 1996 rate case, BPA has proposed to eliminate the Irrigation Discount.

The PPC argues that the Settlement Agreement precludes parties from raising rate design issues in BPA's 1995 rate case. PPC's Br., B-PP-01, 5. This argument is incorrect. The Settlement Agreement does not preclude parties from raising issues in the 1995 rate case. BPA recognized that parties not signatories to the Settlement Agreement might have questions or concerns regarding BPA's 1995 rate proposal. BPA cannot and has not denied such parties the ability to litigate such issues. Any issue raised by a party must be reviewed by BPA and a decision made based on the rate case record.

***Decision***

*Changes in the Irrigation Discount in this proceeding are inappropriate. Elimination or modification of the Irrigation Discount at this time could result in undue impacts on irrigation end-users that could be offset or avoided if changes were made within the*

*context of a more comprehensive examination of BPA's rates. BPA currently is reviewing rate design issues, including the Irrigation Discount, in BPA's 1996 rate case. In BPA's initial proposal for the 1996 rate case, BPA has proposed to eliminate the Irrigation Discount. BPA will retain the discount, however, for its 1995 rates.*

### 3.2.2. Low Density Discount (LDD)

***Issue***

*Whether BPA should eliminate the LDD for irrigation loads in the PF-95 and NR-95 rate schedules.*

**Parties' Positions**

CBI argues that BPA should eliminate the LDD associated with 1994 irrigation loads. CBI Br., B-CB-01, 22. NIU argues that CBI's proposal to eliminate the LDD has no merit, is inconsistent with BPA's system-wide methodology for determining the discount and is contrary to the Northwest Power Act. NIU's Br., B-NI-01, 10. The PPC argues that CBI's proposal is inconsistent with the Northwest Power Act. PPC Br., B-PP-01, 5-6.

**BPA's Position**

BPA notes that CBI's proposal is inconsistent with BPA's methodology and statutory directives. Moorman, E-BPA-21, 9.

**Evaluation of Positions**

In its testimony, CBI's argument for eliminating the LDD for irrigation loads was that many irrigation loads are large, which implies that portions of a given utility system dedicated to non-family farms do not fit the definition of a low density system. Bell, E-CB-01, 21. This argument is not persuasive. The LDD does not depend on whether individual customers or portions of a utility's service territory comprise low density systems. Moorman, E-BPA-21, 9; Saven E-NI-01, 11-12. The LDD is intended to avoid adverse impacts on retail rates of BPA's customers with low system densities overall. 16 U.S.C § 839e(d)(1). The LDD therefore is based on a utility's entire system within the Pacific Northwest and not on the density of individual utility consumers. Moorman, E-BPA-21, 9; Saven E-NI-01, 11-12. The purpose of the LDD is distinctly different from the purpose of the Irrigation Discount and should not be eliminated for irrigation loads. Moorman, E-BPA-21, 9.

***Decision***

*The LDD is properly based on a utility's entire system within the Pacific Northwest region. The LDD will be retained in BPA's 1995 rates.*

### 3.2.3 The 7(b)(2) Rate Test

Section 7(b)(2) of the Northwest Power Act directs BPA to conduct, after July 1, 1985, a comparison of the projected rates to be charged its preference and Federal agency customers for their general requirements with the costs of power (hereafter called rates) to those customers if certain assumptions are made. 16 U.S.C. 839e(b)(2). The effect of this rate test is to protect BPA's preference and Federal agency customers' wholesale firm power rates from certain specified costs resulting from provisions of the Northwest Power Act. The rate test can result in a reallocation of costs from the general requirements loads of preference and Federal agency customers to other BPA loads.

The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements of BPA's public body, cooperative and Federal agency customers (7(b)(2) customers). The two sets of rates are: (1) a set for the test period and ensuing 4 years assuming that section 7(b)(2) is not in effect (program case rates); and (2) a set for the same period taking into account the 5 assumptions listed in section 7(b)(2) (7(b)(2) case rates). Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act are subtracted from the program case rates. Next, each nominal rate is discounted to the test year of the relevant rate case. The discounted program case rates are averaged, as are the 7(b)(2) case rates. Both averages are rounded to the nearest tenth of a mill for comparison. If the average program case rate is greater than the average 7(b)(2) case rate, the rate test triggers. Based on the extent to which the test triggers, the amount to be reallocated in the rate proposal test period is calculated.

The methodology to implement section 7(b)(2) was developed in a section 7(i) proceeding that preceded the 1985 rate case. The section 7(i) process culminated in the Section 7(b)(2) Implementation Methodology Record of Decision. 7(b)(2) ROD, b-2-84-F-02. Issues requiring interpretation of the statute were resolved in the Legal Interpretation for Section 7(b)(2), 49 Fed. Reg. 23,998 (1984).

In BPA's initial proposal for the 1995 rate case, the section 7(b)(2) rate test did not trigger. During the rate case, no party raised any issue regarding section 7(b)(2) in testimony or in brief. For these reasons, BPA will conduct the rate test for BPA's final proposal in the same manner as in BPA's initial proposal.

## 3.3. Transmission Rates

BPA's transmission rates were increased by a 4 percent surcharge to each component of its adjustable rates. Metcalf et al., E-BPA-17, 8. The adjustable transmission rates include: the Formula Power Transmission (FPT-95.1 and FPT-95.3) rates; the Integration of Resources (IR-95) rate; the Energy Transmission (ET-95) rate; the Southern Intertie Transmission (IS-95) rate; the Northern Intertie Transmission (IN-95) rate; and the Eastern Intertie Transmission (IE-95) rate. The following transmission rates were

extended unchanged: Use of Facilities rate (UFT-95), Market Transmission rate (MT-95), and Townsend-Garrison Transmission rate (TGT-95). Id.

The FPT-95.3 rate applies under FPT contracts that provide for rate changes no more often than every 3 years. BPA originally intended to propose significant changes to the rate design and rate levels of its transmission rates, including FPT-95.3, in its 1995 rate proposal. Metcalf, et al., WP-95-E-BPA-15, 16, 17. BPA and its customers, however agreed to defer the complex rate case for 1 year to allow "coordinating implementation of new BPA power sales contracts and rate structure until October 1, 1996," and to provide "additional time in the rate case schedule to address BPA's proposed new rate designs." See Moorman, WP-95-E-BPA-13, Attachment B, 2. By increasing the components of the FPT-95.3 rate by 4 percent consistent with the rate proposal pursuant to the Settlement Agreement, BPA is not precluded from increasing the FPT-95.3 rate, as necessary, in its 1996 rate case. Metcalf et al., E-BPA-17, 9.

### 3.3.1 Southern Intertie Annual Cost Rate

In the 1995 rate case, BPA proposed the Southern Intertie Annual Costs (AC-95) Rate and Billing Provisions to replace the 1993 Southern Intertie Annual Cost (AC-93) rate and associated General Transmission Rate Schedule Provisions. Parker, Hagen, WP-95-E-BPA-20. Since the Fall of 1994, BPA has signed PNW AC Intertie Capacity Ownership Agreements with six parties. These contracts provide life-of-facilities capacity rights to Capacity Owners totaling 725 MW of BPA's share of the PNW AC Intertie. The proposed AC-95 rate is one of two rates associated with the Capacity Ownership Agreements that allow BPA to recover the costs associated with the PNW AC Intertie capacity rights. The Capacity Ownership (CO-94) rate recovers the actual capital and related costs of facilities. The AC-95 rate will recover the actual annual costs associated with Capacity Ownership, as well as the actual capital costs of PNW AC Intertie replacements and reinforcements. Id. at 1-2.

The AC-95 rate provides for Capacity Owners to pay actual costs of: (1) operations, maintenance, general plant, and other identified expenses, including end-of-term expenses; and (2) capital costs of replacements and reinforcements. The annual expenses shall be paid monthly during a fiscal year based on a forecast of such expenses, and trued-up to actual expenses after the end of the fiscal year. The capital costs of replacements and reinforcements shall be billed to Capacity Owners within 15 months after the project work order is closed. The associated Billing Provisions are similar to those in the General Transmission Rate Schedule Provisions, but are tailored specifically to the PNW AC Intertie Capacity Ownership Agreements. Id., at 2-3.

BPA is seeking life-of-facilities approval for the AC-95 rate and associated Billing Provisions. Regardless of how the actual costs of operating and maintaining the PNW AC Intertie and the actual costs of replacements and reinforcements change over time, the Capacity Owners always will pay their share of actual costs under the proposed rate. Life-of-facilities approval would be consistent with the term of the agreements and the

approved CO-94 rate. Id., at 3. In addition, the costs to be recovered under this rate are small in relation to BPA's total revenue requirement: .1 percent of BPA's total annual revenue requirement, or .3 percent of BPA's total annual transmission revenue requirement. Id., at 4.

# 4.0 PROCEDURAL ISSUES

## 4.1 Section 7(i) Process

Section 7(i) of the Northwest Power Act requires BPA to conduct a hearing whenever BPA proposes to revise rates for the sale of power or transmission of non-Federal power services. 16 U.S.C § 839e(i). BPA has established procedures governing such hearings. See Procedures Governing Bonneville Power Administration Rate Hearings, 51 Fed. Reg. 7611 (March 5, 1986). BPA's procedures allow for an expedited hearing to be conducted within 90 days after notice published in the Federal Register. BPA adopted the procedures allowing for a 90-day hearing in order to provide the Administrator with a mechanism for revising rates expeditiously when the Administrator has determined that, among other things, delays could significantly harm BPA's ability to satisfy its statutory obligations. See Portland General Elec. Co. v. BPA, 754 F.2d. 1475 (9th Cir. 1985); California Energy Comm'n v. BPA, 754 F.2d 1470 (9th Cir. 1985). During the course of the hearing, a number of procedural issues were raised regarding the adequacy of BPA's initial proposal and the 90-day hearing process.

### 4.1.1 Adequacy of Initial Proposal

***Issue***

*Whether BPA's initial proposal was sufficiently complete to provide rate case parties the procedural rights afforded them by section 7(i) of the Northwest Power Act.*

**Parties' Positions**

CBI claims that BPA's initial proposal filed on May 1, 1995, was incomplete. CBI Motion to Strike Errata, WP-95-M-2, 3; CBI Br., B-CB-01, 5-6. CBI alleges that BPA's initial proposal failed to include information relating to recent agreements between BPA and its utility and DSI customers allowing such customers to purchase a portion of their load from other suppliers (DSI and utility waiver agreements). CBI Br., B-CB-01, 4. CBI claims the waiver agreements changed BPA's load/resource balance and affected BPA's revenue requirements and revenue forecast but were not reflected in the Loads and Resources Study, the Revenue Requirement Study and the Revenue Forecast Study. Id. CBI argues that because of these deficiencies CBI was deprived of: (1) its procedural right to notice of BPA's initial proposal; and (2) any opportunity to analyze the initial case and file meaningful testimony. Id. CBI claims that because BPA's initial proposal was not complete when published May 1, 1995, the proposal was not "out in public" for 90 days. Id.

**Evaluation of Positions**

CBI argues that because the initial proposal that BPA filed on May 1, 1995, was incomplete, CBI was deprived of its procedural right to notice of BPA's initial proposal under section 7(i) of the Northwest Power Act. CBI Motion to Strike Errata, WP-95-M--2, 3; CBI Br., B-CB-01, 4-5. In particular, CBI claims that errata submitted by BPA after May 1, 1995, contain information relating to the utility and DSI waiver agreements that was not included in the initial proposal. Id. This information, CBI claims, changed the results of the initial proposal and the conclusions to be drawn from the analysis presented in BPA's direct filing. Id. Procedural issues associated with the errata are discussed in issue 4.1.2., infra.

Under section 7(i) of the Northwest Power Act, BPA is required to publish in the Federal Register a "notice of the proposed rates," and "a statement of the justification and reasons supporting such rates." 16 U.S.C. § 839(e)(i)(1). BPA's procedures governing its rate hearings further provide that the notice shall:

(a) specify the proposed rates and summarize any studies, analysis, or other available information that BPA intends to use in the hearing to justify the proposed rates,
(b) establish a deadline for filing petitions to intervene,
(c) state whether the hearing will be conducted under the rule for general rate proceedings, section 1010.9 or the rule for expedited rate proceedings, section 1010.10, together with a statement of the reasons for the Administrator's choice between the two rules;
(d) establish the date on which the hearing officer will conduct the prehearing conference,
(e) specify the date on which the Administrator will issue the record of decision, which date shall be used by the hearing officer in establishing the procedural schedule for the hearing, and
(f) provide other information which the Administrator determines to be pertinent to the hearing.

Procedures Governing Bonneville Power Administration Rate Hearings, 51 Fed. Reg. 7611 (March 5, 1996).

BPA meets the procedural notice requirements by providing notice of: (1) its proposed actions; and (2) the bases for the proposed actions. As the Ninth Circuit has held, "[s]ection 7(i)(2)(A) ensures that BPA creates a complete administrative record, allowing all interested parties to participate in a meaningful way. This does not mean that each time BPA adjusts the conclusions to be drawn from the record, new notice and comment must begin." Central Lincoln Peoples' Utility District v. Johnson, 735 F.2d 1101, 1108, (9th Cir. 1984).

On May 1, 1995, BPA published a notice of its proposed rates in the Federal Register consistent with the section 7(i) requirements and BPA's procedural rules. 60 Fed. Reg. 21132 (1995). The May 1, 1995, Federal Register notice described the situation leading to BPA's proposed 1995 rates including a detailed discussion of the events leading to the Settlement Agreement. Id. In the Federal Register notice, BPA noted that competitive forces are causing a fundamental and significant change in the Pacific Northwest wholesale power market. Id. To respond to these changes BPA noted that it was proposing to fundamentally change its rate designs. BPA further stated that in light of these fundamental rate design charges, the rate case parties wanted an 8-month hearing process. Id. BPA's current 1993 rates, however, with a few exceptions, have been approved by FERC only through September 30, 1995.

In the May 1, 1995 Federal Register notice BPA expressed concern that without an adjustment to its wholesale power and transmission rates for the period October 1, 1995, through September 30, 1996, BPA's ability to satisfy its statutory obligations could be impaired. 60 Fed. Reg. 21132 (1995). In order to have sufficient time to conduct a full rate proceeding for new rate design changes, including 2- and 5-year rate proposals, BPA and most parties to the 1995 rate proceeding agreed that BPA would propose to extend BPA's current adjustable rates with a 4 percent surcharge for a 1-year period, October 1, 1995, through September 30, 1996. As such, BPA noted in the Federal Register that the extension of rates required a separate expedited proceeding and procedural schedule. Id.

The Federal Register notice also listed the major studies prepared to support BPA's 1995 initial proposal, which consisted of a Loads and Resources Study and Documentation; a Revenue Requirement Study and Documentation; a Revenue Forecast Study and Documentation; and a Section 7(b)(2) Rate Test Study and Documentation. Id. The notice also contained a brief description of each of the studies. BPA noted that purchases from alternative (non-BPA) power suppliers are an issue in the development of BPA's load forecasts. Id. In addition, BPA described how its proposed wholesale power and transmission rates were established consistent with the Settlement Agreement. Id.

On the same day, May 1, 1995, BPA's initial testimony was made available to the parties. Parties were informed that several errors or omissions were discovered that could affect the amount of revenues expected during FY 1996. Metcalf, et al., E-BPA-17, 5. BPA's direct testimony identified the following changes to the initial revenue forecast: (1) reduce the costs of some purchased power and include additional amounts; (2) lower the expected storage balances entering FY 1996; (3) *reduce the estimate of the DSI First Quartile market*; (4) revise the rates for some long-term SP sales; (5) eliminate energy returns from spot market seasonal exchange contracts that are not likely to materialize due to wet weather in California; (6) include some surplus capacity sales; and (7) increase expected wheeling revenues. Id. In addition, BPA provided a preliminary estimate of the change in revenues. In its direct testimony, BPA noted that its preliminary estimate is that revenues under both current and proposed rates would be lower by about $55 million. Id. Finally, BPA stated that this reduction in forecasted revenues would be factored into the

Revenue Requirement Study for the final rate proposal as a reduction in net revenues for risk and not as an additional increase in rates. DeWolf et al., WP-95-E-BPA-16, 23. Parties were informed that a revenue reduction of about $50 million would lower the probability of Treasury payment by 4 percent from what was cited in BPA's studies. Id.

CBI complains that it did not understand that the bulk of this revenue revision was to reflect the DSI waiver agreements. CBI Br., B-CB-01, 17. CBI asserts that despite its repeated requests BPA did not provide information that the bulk of the revenue reductions was due to DSI waivers until rebuttal testimony. Id. CBI is mistaken. BPA provided this information to CBI in response to a data request over one week prior to when CBI filed its testimony and within the deadlines for discovery established by the Hearing Officer. See Exhibit E-CB-04, BPA's Data Response to CBI, CBI/BPA:4; Tr. 44. See also NRDC v. Thomas, 838 F.2d 1224 (D.C. Cir. 1988) (parties had adequate opportunity to comment when informed about the presumptions for the final decision less than 2 weeks before promulgation of the final decision.)

Shortly after BPA filed its direct testimony, BPA filed errata to the Loads and Resources Study to reflect the recent waiver agreements between BPA and its utility and DSI customers. See Errata to Loads and Resources Study, WP-95-E-BPA-09 (E1) and (E2). The errata were provided within the time for discovery and are part of BPA's initial proposal. Procedural issues raised by parties about BPA's errata are discussed in more in more detail in section 4.1.2, infra.

BPA met its procedural notice requirements. Based on the information in the Federal Register notice, BPA's testimony, and the information available through discovery, CBI was provided its procedural right to notice of BPA's initial proposal under section 7(i) of the Northwest Power Act CBI knew or should have known that BPA was proposing to adjust its rates and that the initial proposal would be based on the settlement agreement. In addition, CBI had notice of the rates and the studies that BPA relied on to support its initial proposal. CBI knew or should have known that BPA was facing competitive pressures and that purchases from alternative (non-BPA) power suppliers were an issue in the development of BPA's load forecasts for its utility and DSI customers. And finally CBI knew or should have known that BPA planned to adjust its revenue forecast and the load forecast to reflect the recent waiver agreements.

CBI argues that BPA should have delayed its initial filing until the consequences of the waivers could be included in all its testimony and documentation. CBI Br., B-CB-01, 6. CBI's implied argument is that BPA should have rerun its entire rate case to reflect the waiver adjustments to the load forecast. Apparently, CBI believes that it has been deprived of its procedural rights under section 7(i) because BPA did not actually rerun all its studies but only described the new data to be used in the studies and provided an estimate of the changes resulting from using this new data. The logical effect of CBI's conclusion is that BPA would never develop new rates if BPA were forced to delay its initial proposal until the data and information on which the rates are based are no longer subject to change and therefore can be incorporated in all BPA's studies and testimony.

Contrary to CBI's argument, the notice requirements under section 7(i) does not require BPA to start the 7(i) process anew whenever BPA needs to make changes to the proposed rates during the course of the rate case. Central Lincoln Peoples' Util/ Dist/ v. Johnson, 735 F.2d 1101, 1118 (9th Cir. 1984); see also 1993 Administrator's Record of Decision, WP-93-A-02, 301-313. The notice requirements mean that BPA has sufficiently described the subject and issues involved so that parties may offered informed comments. The notice requirements do not mean that BPA must publish in advance every possible proposal that it may ultimately adopt. California Citizens Band Assoc. v. U.S., 375 F.2d 43 48-49 (9th Cir. 1967). In the 1993 rate case, parties also argued that BPA must rerun all its studies to satisfy the section 7(i) notice requirements. That issue was discussed at length in the Administrator's Record of the Decision. See 1993 Administrator's Record of Decision, WP-93-A-02, 301-313, incorporated by reference herein. For the same reasons described in the 1993 Record of Decision, the notice requirements in section 7(i) do not require BPA to rerun all its studies every time new data or information is raised during the course of a rate hearing.

CBI has been fully aware of the expedited schedule of this proceeding. CBI participated in the prehearing conference where the schedule was discussed, yet at that time counsel made no objection to the schedule. CBI also had notice of the need for the expedited schedule. See Generally Transcript of Prehearing Conferences February 13, 1995, March 15, 1995, and March 22, 1995. Pursuant to FERC regulations governing rate review and approval of BPA's major rates, "Rate schedules of the Bonneville Power Administration for which interim approval by the Commission is requested must be filed not later than 60 days in advance of the proposed effective date." 18 C.F.R. § 300.10(a)(3)(ii) (1994). BPA's rates currently in effect expire September 30, 1995, and BPA must have new rates in effect October 1, 1995. Thus, in order to comply with FERC regulations, BPA must file its proposed rates with FERC on August 2, 1995.

Although this case is taking place under the rule for "expedited" rate hearings and must be completed within 90 days, CBI has repeatedly requested significant additional time as a result of its procedural motions. However, if CBI were truly concerned about the revenue shortfall associated with BPA's surcharge rates, as it professes in its testimony, it would not seek to delay. If BPA cannot recover costs at the proposed surcharged rates, it would have an even harder time recovering costs if the effective date of the surcharged rates were delayed.

CBI claims that the schedule does not allow adequate time to review data responses and prepare for cross-examination. Yet CBI did not take advantage of opportunities made available to the parties in the schedule. CBI did not attempt to use the opportunity provided in the schedule for clarification of BPA witnesses on June 21, 1995. The number of data requests submitted to BPA might have been significantly reduced if CBI had participated in clarification. CBI did not use its opportunity granted by the Hearing Officer to supplement the record as a result of errata filed by BPA. WP-95-O-09. In an order issued June 6, the Hearing Officer allowed CBI to file supplemental testimony by

June 14, 1995 on the errata. Although CBI had over a week to prepare its testimony, CBI claims that it wasn't given enough time to file a "meaningful" response. WP-95-M-24, 5 See Florida Economic Advisory Council v. Federal Power Comm'n, 251 F.2d 643, 648 (D.C. Cir. 1957) (announcing the deadline for submitting briefs, nine days before the deadline is not so short a time as to amount to denial of substantial rights considering the need for an expedited process). In addition, although completely within its rights, CBI did not serve its data requests until near close of business the date they were due. However, if CBI had not waited until the deadline to serve data requests, the responses it claims it needed to prepare for cross-examination would have been available to it sooner. See Order on Data Request Procedures, WP-95-O-03 (responses to data request are due seven (7) calendar days from receipt of the request). In any case, since it has been fully aware of the schedule in this case, CBI should have been prepared to spend the time necessary to review the data request responses.

CBI knew that matters would be handled on short time frames and should have been prepared to spend the time to see the issues through on the schedule established at the beginning of this proceeding in March, 1995. All litigants have been subject to the same schedule constraints in this proceeding.

***Decision***

*BPA's initial proposal was sufficiently complete to provide rate case parties the procedural rights afforded them by section 7(i) of the Northwest Power Act.*

### 4.1.2 Hearing Officer's Denial of Motion to Strike Errata

***Issue***

*Whether errata submitted by BPA were procedurally improper or otherwise deprived rate case parties of the procedural rights afforded them by section 7(i) of the Northwest Power Act.*

**Parties' Positions**

CBI argues that the 90-day rate case schedule was premised on BPA filing its direct case on May 1, 1995, but that BPA filed errata to its direct case which made integration, analysis and meaningful response impossible. CBI Br., WP-95-B-CB-01, 6.

**BPA's Position**

Many of the errata objected to by CBI were simply corrections to the record which were provided in a timely manner and which caused no prejudice. Answer of Bonneville Power Administration in Opposition to Columbia Basin Institute's Motion to Strike Errata, WP-95-M-14 (Answer). Additional errata that contained information that could not be incorporated in the initial proposal actually were advocated by CBI and were provided

within the deadline established for responses to data requests. Id. Other errata containing a small amount of supplemental testimony were not substantial and involved an issue in which CBI had no interest and filed no testimony. Id., at 13. The Hearing Officer denied CBI's Motion, but provided CBI an extension of time to file responding testimony. WP-95-0-09. CBI chose to file no additional testimony. CBI therefore was allowed to participate meaningfully in the proceeding and was not prejudiced by BPA's errata.

**Evaluation of Positions**

CBI argues that because BPA filed errata to its initial proposal, CBI was not provided adequate time to participate in the rate case. CBI Br., B-CB-01, 3-7. In particular, CBI argues that BPA's errata filed May 23, 1995, were not corrections but instead involved 15 new lines of text replacing and amending the prefiled exhibit. Id. at 4. BPA filed three errata to testimony regarding rates under the proposed Pacific Northwest Coordination Agreement (PNCA), WP-95-E-BPA-19. Admission of these errata into evidence did not prejudice CBI. First, the errata made very minor changes to the testimony. WP-95-M-14. The first erratum added a nuance to the Interchange Energy Service Charge, which was discussed in detail in the testimony. Id. The erratum explained that ordinarily interchange energy is not delivered during peak hours and that if it is delivered during peak hours a reshaping charge applies. Id. The second erratum then added the reshaping charge to the schedule of rates attached to the testimony (Attachment A to WP-95-E-BPA-19). In effect, then, the two errata made but one minor change.

The third erratum added nothing of substance to what the testimony already contained. See Answer, M-14. The testimony explained the circumstances under which the Holding Interchange Energy (HIE) Service Charge would be refunded. This two-mill charge is refunded in two stages: .75 mills per kilowatthour when HIE is converted to Storage Energy, and 1.25 mills per kilowatthour when the energy is spilled. Attachment A, however, indicated simply that the 2-mill charge would be refunded if HIE was converted to Storage Energy and spilled. The attachment omitted the two-step process. The erratum corrected the attachment so that it conformed to the testimony. Id. CBI did not address either these charges or any other aspect of the PNCA testimony or PNCA rates in its testimony, prehearing brief, or initial brief.

CBI filed a motion to strike the errata during the rate hearing. CBI Motion to Strike Errata, WP-95-M-12. While the Hearing Officer denied the request to strike the errata, he ruled that "since the errata may have impeded CBI from fully addressing all aspects of the case, CBI shall be permitted to file supplemental testimony until June 14, 1995. All such testimony shall only address errata indicated by CBI in its motion to strike." Order Denying CBI's Motion to Strike Errata, WP-95-O-09. CBI did not file supplemental testimony. It is clear that CBI has no interest in BPA's proposal for PNCA rates and that it was not prejudiced by the admission of the PNCA errata.

CBI also challenges a second set of errata filed by BPA to reflect waiver agreements in the Loads and Resources Study. CBI Br., B-CB-01, 4. CBI argues that BPA entered into

waiver agreements with its public agency and DSI customers that changed BPA's load/resource balance. Id. at 3-4. CBI argues that BPA did not account for this change in its initial Loads and Resources Study. Id. at 4. BPA filed errata, however, which reflected the waiver agreements in the Loads and Resources Study and Documentation. See Errata to Loads and Resources Study, WP-95-E-BPA-09(E1) and (E2). These errata were filed within the time prescribed in the rate case schedule for responses to data requests, taking into account the date that corrected copies of CBI's data requests were filed with BPA.

CBI argues that BPA distributed "over one hundred 'Errata' to [the] Loads and Resources Study and . . . Documentation." CBI Br., B-CB-01, 4. In fact, however, BPA filed: (1) one errata sheet to reflect the waiver agreements for the load forecasts of Generating Public Utilities and Non- and Small Generating Public Utilities (including an illustrative table); and (2) one errata sheet for the DSI load forecast. These errata were necessary in order for parties to see the effects of the waiver agreements on the Loads and Resources Study.

CBI also argues that the information in the errata was available in time to be incorporated in BPA's initial proposal. Id., 4-5. The errata state, however:

> At the time the Loads and Resources Study was prepared, BPA did not have the results of the recent waiver agreements with its customers.

See Errata to Loads and Resources Study, WP-95-E-BPA-09(E1) and (E2).

CBI argues that a table provided with the errata contains a statement "Updated April 17, 1995," a date two weeks before BPA filed its initial case. CBI Br., B-CB-01, 4. CBI then argues that the table had been compiled by that date or, as of that date, all the waiver information was known. Id. The document upon which CBI bases its argument is not in the rate case record and, therefore, does not support CBI's argument. Furthermore, CBI's argument is the same argument presented in its motion to strike the errata. CBI fails to note the refutation of its argument in BPA's answer to CBI's motion to strike. See Answer, M-14, 12 fn. 8. CBI is unfamiliar with the document and consequently failed to note that the table was not finalized until May 18, 1995, the day before it was provided to CBI in response to a data request. The table had been available on computer in earlier drafts and periodically had been reviewed and updated. One such review and update occurred on April 17, 1995. However, the table as it existed on April 17, 1995, was not the same table that appears in the errata. When the final table was prepared on May 18, 1995, BPA staff failed to update the previous date on the table. CBI's argument thus is incorrect, although BPA can understand CBI's confusion.

CBI also argues that BPA knew before May 19, 1995, that it had entered into waiver agreements, many of which are dated March of 1995. Id. This argument also was refuted by BPA. See Answer, M-14, 12 fn. 8. In fact, none of the utility waivers were signed in March and only about half of the DSI waivers had been signed in late March. A review of

the factual history of the development of BPA's initial proposal and the development of waiver agreements with BPA's customers demonstrates that BPA's revisions regarding the waivers could not be incorporated in BPA's initial load forecasts. See Answer, M-14. BPA's rate case is a complex and sequential undertaking. One of the first steps in the development of rates is the development of load forecasts. Load forecasts are used in the development of subsequent studies in the rate development process. In accordance with BPA's internal schedule for the initial rate proposal in the rate case, most work regarding BPA's load forecasts was conducted in March 1995. See Documentation for Loads and Resources Study, WP-95-E-BPA-09A.

At the same time BPA was developing its load forecasts, BPA and its customers were discussing the possibility of BPA's waiving notice requirements to permit customers to withdraw loads from BPA earlier than otherwise would be required under the customers' contracts. See Lee, et al.,, WP-95-BPA-14, 13-14. Waivers are achieved only through separate agreements signed by BPA and the participating customer. Even though the possibility of waivers was being discussed, there was great uncertainty regarding whether parties would sign such agreements. Indeed, the first utility waiver agreement was not executed until April 21, 1995, and the waiver had until July 5, 1995, to accept or reject the waivers. BPA submitted its studies and testimony for reproduction on April 21, 1995, which was only 5 working days prior to release of BPA's initial proposal on May 1, 1995. The single waiver agreement signed did not provide a sufficient basis for BPA to assume that all waiver agreements that had been offered would be executed. Many utility waiver agreements still had not been received by BPA at the time BPA submitted its initial proposal for reproduction. While the majority of DSI waiver agreements were received in March and April, the DSI waiver agreements were not completed until May 4, 1995.

Furthermore, even with knowledge that some waiver agreements would be executed, other factors must be considered in determining the nature of any adjustment to the load forecasts, including, for example, alternative BPA SP offers, incentive rates, or inability of a customer to actually acquire alternative power within FY 1996. BPA therefore developed its initial proposal with load forecasts which, due to scheduling constraints, reflected the best information available.

Although BPA could not properly incorporate the waivers in BPA's initial load forecasts, BPA recognized the need for a correction in the event that the waivers were accepted. Furthermore, CBI's own testimony advocates reflecting the waivers in BPA's load forecasts. Bell, E-CB-01, 7-8. BPA was faced with either: (1) proceeding with its existing load forecasts which it subsequently knew to be inaccurate due to the waiver agreements; or (2) filing errata to the initial studies to reflect the waiver agreements and thereby provide all parties the opportunity to address the more accurate forecast. When BPA believed that the waivers likely would be accepted and was better able to evaluate other factors as noted above, BPA sought to advise parties of the effect of such waivers on BPA's load forecast. This action also responds to the interest of CBI in this issue, as demonstrated at the clarification session, by CBI's data requests and ultimately in CBI's testimony. BPA received data requests from CBI suggesting that BPA's initial proposal

would be incomplete or inaccurate unless the waiver agreements were reflected in BPA's initial studies. At the clarification sessions regarding BPA's initial proposal, CBI advocated correction of BPA's Loads and Resources Study to reflect the waiver agreements.

In light of the foregoing facts, BPA filed errata to the Loads and Resources Study and Documentation in order that BPA's initial proposal would reflect the best information available. BPA was surprised by CBI's motion to strike the very information that CBI felt was necessary. CBI attempted to place BPA in an impossible position: if BPA did not update its initial Loads and Resources Study, CBI would argue that the Study was inaccurate because it did not reflect the waiver agreements; if BPA updated the Study to reflect the waiver agreements, CBI would argue that the waiver agreements should have been reflected in the initial Loads and Resources Study and that the updates constituted a new case and should not be allowed. BPA determined that the Loads and Resources Study should reflect the late-breaking waiver agreements and provided that information to the parties through errata within the time permitted for responses to data requests. Because parties are presumed to be able to respond in their direct cases to information received in data responses, parties also would be able to respond to the errata to the Loads and Resources Study provided by BPA.

CBI also challenges a third set of BPA's errata, those directed to the Revenue Requirements Study and the Revenue Forecast Study. CBI argues that BPA distributed several hundred errata to the Revenue Requirement Study and Documentation, WP-95-E-BPA-10(E1) and 10(E2); the prefiled testimony of DeWolf, et al., WP-95-E-BPA-16A(E1); the Revenue Forecast Study and Documentation, WP-95-E-BPA-11(E1) and 11A(E1); and the testimony of Metcalf, et al., WP-95-E-BPA-17(E1). In fact, however, the errata consisted of just over 20 corrections. Admission of these errata into evidence did not prejudice CBI. CBI argues that BPA's errata were not corrections but comprised failure to include information in the initial proposal. To the contrary, these errata corrected clerical errors, inconsistencies, lack of clarity or inadvertent omissions. See Answer, M-14. Furthermore, official versions of the revenue requirement and revenue forecast errata were provided on May 16, 1995, almost two weeks before the filing of parties' testimony. An earlier copy of the revenue forecast errata was available to CBI at clarification of BPA's witnesses, on May 5, 1995, just five days after BPA's initial proposal was published.

Finally, as noted above, CBI filed a motion to strike the errata during the rate hearing. See CBI Motion to Strike Errata, WP-95-M-12. The Hearing Officer permitted CBI to file supplemental testimony until June 14, 1995. See Order Denying CBI's Motion to Strike Errata, WP-95-O-09. CBI did not take advantage of the Hearing Officer's ruling allowing it to file supplemental testimony on the errata.

***Decision***

*BPA properly presented its direct case in this proceeding. Many of the errata objected to by CBI were simply errata as defined by CBI itself which were provided in a timely manner and which posed no procedural problem. Additional errata either were advocated by CBI or concerned issues in which CBI had no interest and filed no testimony. The Hearing Officer provided CBI an extension of time to file supplemental testimony but CBI elected not to file any such testimony. CBI therefore was allowed to participate meaningfully in the proceeding and was not prejudiced by BPA's errata.*

### 4.1.3 Hearing Officer's Rulings on Motions Regarding Data Requests

#### 4.1.3.1 Scope of Data Requests

***Issue***

*Whether the Hearing Officer correctly affirmed BPA's refusal to respond to data requests for material related to the waivers and subsequent surplus power negotiations.*

**Parties' Positions**

After BPA refused to answer certain data requests from CBI on the grounds that they sought information that was beyond the scope of this proceeding or otherwise protected from discovery, CBI filed a Motion to Compel BPA Responses to Data Requests/Memorandum in Support, WP-95-M-13, asserting that the requested information was relevant, id., 3-5, that it was not subject to a Freedom of Information Act exemption, id., 6-7, and that the First Amendment required its release under a protective order, id., 8-11.

**BPA's Position**

BPA filed a Response to Columbia Basin Institute's Motion to Compel BPA Responses to Data Requests, WP-95-M-15, opposing CBI's motion on the grounds the requested information was irrelevant, id., 2-4, that it was privileged under Exemption 5 of the Freedom of Information Act, id., 6-10, that it was subject to protection by the Hearing Officer as proprietary information, id., 10, that the First Amendment did not require its disclosure, id., 12-15, and that releasing it to CBI under a protective order was inappropriate, id., 11-12.

**Evaluation of Positions**

Relevance of the requested information

CBI's Motion to Compel BPA Responses to Data Requests/Memorandum in Support, WP-95-M-13, sets out their position on relevancy. CBI argued that:

> Since the waivers were granted, BPA has been aggressively marketing its new surplus to several of the same entities that were given waivers. Assuming that BPA has performed some kind of analysis in preparing its bids to those entities, the load and resource, revenue requirement, and revenue forecast assumptions and analyses embodied in the bid preparation efforts represents a more current, accurate and complete body of information than is contained in BPA's Initial Rate Filing.

Id. at 4-5. CBI makes a similar argument later in its Motion:

> Presumably, the analysis performed during bid preparation represents BPA's current understanding of its load/resource balance, revenue requirements and revenue forecast, simply because the bid analysis is based on more recent information than the Initial Rate Filing.

Id. at 5-6. Because CBI did not request these analyses in its data requests and subsequent Motion to Compel, the foregoing argument does not address the relevancy of the documents CBI actually requested in its Motion, unless one assumes CBI is arguing that if the analysis behind the bids is relevant, then the bids are as well. Regarding relevancy of the documents actually requested in its Motion, CBI asserted that the terms of the new contracts signed after granting the waivers are relevant to BPA's revenue forecast in this case and that BPA's likelihood of repayment to the U.S. Treasury is always a legitimate rate case issue. Id. at 6.

However, BPA reasonably argued that

> Until and unless the proposals result in signed contracts, however, they do not affect BPA's load and resource balance, revenue recovery, or rates. Contracts based on the proposals may never be signed, or may be signed on terms different from those contained in the proposals. In either case, far from proving helpful to CBI's case, the proposals would only give a false picture of BPA's resource and revenue situation.

BPA's Response to CBI's Motion, M-15, 2. BPA stated that CBI's arguments concerning supporting analyses to the requested proposals was improper because CBI had not requested the analyses. Id., 3-4.

CBI asserts essentially two points supporting its relevancy argument. First, any analyses of loads and resources, revenue requirements and revenue forecasts BPA performed in preparation for its surplus firm power bid offers was the latest and most accurate evidence on those rate case issues. CBI Motion, supra, 4-6. Second, any new contracts signed after granting the contract waivers are relevant to BPA's revenue forecast. Id., 6. The first argument does not apply to CBI's Motion to Compel since CBI did not request any such analyses. Further, assuming only for the sake of argument that such analysis exist, the harm to BPA's competitive position from release of the documents outweighed any additional evidentiary value that might add to information BPA provided concerning its loads, resources, revenue requirements, and revenue forecast. BPA Response, M-15, 16. As to the second argument, BPA provided a copy of the only contract signed after the waiver, the West Oregon contract. BPA Response, M-15, 1; BPA Data Response CBI/BPA:33. Therefore, CBI's second argument is moot. The undisclosed proposals are not relevant to the rate case because they are not signed contracts, may never become signed contracts, or could result in contracts with different terms.

Freedom of Information Act Exemption

CBI also argued that a Freedom of Information Act exemption is not a discovery privilege applicable to the rate case, but that if it were applicable to the rate case, BPA's reliance on the exemption, 5 U.S.C. 552(2)(b)(5), was incorrect because the proposals requested in the Motion were offers to customers and therefore not inter- or intra-agency memoranda. Id. at 6-7.

BPA argued that BPA Rate Case Procedure Rule 1010.8(f) incorporates Freedom of Information Act exemptions into the rate case discovery procedures. M-15, 6.

BPA argued that the Supreme Court in Federal Open Market Committee v. Merrill, 443 US 340 (1979) had established a privilege for confidential commercial information such as the withheld Alcoa proposals, applying Exemption 5 to the Freedom of Information Act, 5 U.S.C. § 552 (b)(5). BPA Response to CBI's Motion, supra, 7-10. BPA referred to legislative history cited by the Supreme Court in which Government agencies testified before Congress that they needed legislation to protect from discovery materials developed during negotiations. Id., 8. BPA argued that disclosure of Items 16 and 17 in BPA's Data Response to WP-95 Data Request CBI/BPA:38, which were materials relating to confidential negotiations that had not closed, id., 3, 9, and Ex. A at 2, could cause BPA losses in excess of $5.15 million per year for up to 10 years, and that routinely required disclosure of similar materials would cause substantially greater losses due to competition. Id., 9. BPA also stated that "the negotiation process is an ongoing deliberative process, both internally and with the customer, until agreement is reached." Id., Ex. A at 1. Clearly, the Alcoa bid proposals meet the test of confidential commercial information. They also meet the test of inter or intra-agency memoranda. Confidential proposals are developed internally prior to a final agency decision as to whether a contract will be signed. Those proposals are shared confidentially with the customer. If the customer does not accept the proposal as made, BPA receives feedback from the

customer regarding the proposal, which BPA then takes back for further internal deliberation prior to completion of the negotiations. The internal deliberations result in a further decision whether to offer a new proposal, accept the customers' comments, or terminate negotiations. See id., Ex. A at 1. Thus, the unaccepted Alcoa proposals are predecisional internal documents. As such, they fall under Freedom of Information Act Exemption 5, which is incorporated into BPA's rate case discovery procedures.

Proprietary Protection Under BPA Discovery Rules

BPA also argued that if the Hearing Officer should find that Exemption 5 did not apply, he should apply his general authority under BPA Rate Case Procedure Rule 1010.8(f) to preclude disclosure of the information to prevent harm to BPA's competitive interests. BPA Response to CBI Motion, M-15, 10. CBI asserted no position on this issue.

BPA's Rate Case Procedures, section 1010.8(f), allows the Hearing Officer to find that the Alcoa proposals are proprietary and order that they may be withheld, without meeting the tests of Exemption 5 to the Freedom of Information Act. Because of the potential significant competitive cost described above from release of the materials, the Hearing Officer would have been justified in finding the materials proprietary apart from the Freedom of Information Act.

First Amendment Disclosure, Subject to Protective Order

CBI argued that even if the requested documents were subject to a Freedom of Information Act exemption, because of CBI's First Amendment right to discovery, the Hearing Officer should order their release subject to an appropriate protective order protecting BPA's competitive interests. CBI Motion, supra, at 8-11.

BPA argued that CBI incorrectly cited cases in support of its asserted First Amendment discovery right because none of the cases established a right to discovery. BPA Response to CBI Motion, supra, 12-15. BPA also argued that limited disclosure of the requested material under a protective order would be inappropriate in a rate case because the protective order could not prevent CBI from using the material in the rate case and thus exposing it to BPA's customers and competitors. Id., 11-12. BPA argued that all parties to the rate case must have equal access to the evidence, so a protective order allowing CBI alone to view the evidence would violate other parties' right to review the evidence. Id., 12.

The cases cited by CBI in support of a First Amendment right to discovery of the Alcoa proposals do not provide a right to discovery. CBI did not explain how it would have been able to use the Alcoa proposals in a way that would have kept them confidential. As BPA pointed out in its Response to the Motion to Compel, Rate Case Procedures require all parties to have access to discovery evidence. Because BPA's other customers and competitors are parties to the rate case, there is no valid protective order that the Hearing Officer could have made to preclude the information from being accessible to competitors.

***Decision***

*The Hearing Officer correctly denied CBI's Motion to Compel on all the grounds advanced by BPA.*

**4.1.3.2 Sufficiency of the Record to Support the Decision**

***Issue***

*Whether BPA's refusal to enter predecisional and other sensitive information pertaining to sales negotiations into the ratemaking record renders the Administrator's final establishment of rates arbitrary and capricious.*

**Parties' Positions**

This argument apparently arises from CBI's failed attempts to obtain information on contract negotiations described in section 4.1.4.1. CBI argues "[a]ssuming that BPA performed some kind of analysis" regarding "load[s] and resource[s], revenue requirement[s], and revenue forecast assumptions" in preparing surplus firm power bids for customers granted service waivers under their power sales contracts, BPA withheld this "best evidence of pricing . . . , [and] the record is incomplete." CBI Br., WP-95-B-CB-01, 8. CBI argues that "[t]he standard of review applicable to the eventual decision will be whether 'substantial evidence' supports the Administrator's decision to increase rates by only 4 percent and to maintain subsidies to agricultural users. Given the defective evidence about loads and revenues, the Administrator runs a risk of decision which is 'arbitrary, capricious, an abuse of discretion or otherwise not in accordance with law.'" Id., 7.

**BPA's Position**

There is substantial evidence to support the proposed rates and that the Administrator's decision comports with law. Furthermore, information that was denied to CBI under its failed discovery requests was irrelevant to the determination of the rates

**Evaluation of Positions**

CBI argues that "[g]iven the defective evidence about loads and revenues, the Administrator runs a risk of decision which is 'arbitrary, capricious, an abuse of discretion or otherwise not in accordance with law.'" Id., 7 CBI has made contradictory argument. It argues that BPA's errata to support its load forecast were improper at the same time that it argues that material it sought in discovery was crucial to the same determination. In both cases CBI presented its arguments to the Hearing Officer and was appropriately denied relief. WP-95-0-9; WP-95-0-10.

Moreover, CBI did not expressly request the analysis it now says is crucial to a decision. CBI filed no data request specifically for load and resource, revenue requirement, and revenue forecast assumptions regarding the surplus bid proposals and did not move to compel production of such analyses, or of the workpapers that CBI requested earlier. See WP-95 Data Requests CBI/BPA:33 -38; CBI Motion to Compel, supra. Instead, CBI moved to compel production only of the bids themselves. Its failure to request production of any load, resource, revenue requirement and revenue forecast analysis contradicts CBI's latest assertion that the analyses were important to the case.

CBI has failed to explain how withholding the analyses creates a defective record. BPA provided workpapers supporting the West Oregon sale and supporting the October 1994 DSI surplus offer. See BPA Response, M-15, 1. In addition to the foregoing workpaper, BPA provided bids prepared for West Oregon and Clark and the signed contract with West Oregon. Id.. CBI made no substantive arguments based on those bids or contract. See CBI Br., supra, 7-10. CBI's failure to use information that BPA provided in response to CBI's data requests demonstrates that this argument is a red herring. BPA's decision in this case does take into account load and revenue impacts due to the waivers.

In its original data requests, CBI requested "workpapers" supporting BPA surplus firm power bid proposals. After BPA refused to provide the confidential material, CBI filed a motion to compel, requesting only the proposals themselves and not the supporting workpapers. See WP-95-M-13. CBI never requested the "load and resource, revenue requirement, and revenue forecast assumptions" information that it now asserts are missing from the record. Aside from CBI's assertion in its brief that such documents must exist, there is no evidence in the record that any such analyses indeed exist, other than the analyses BPA produced in Data Responses CBI/BPA:33-38. BPA Response, M-15, 1. Thus, BPA has had no opportunity to respond to the specific question of whether such analyses exist. Furthermore, there is no proof in the record that they exist, aside from CBI's argument that assumes - "[a]ssuming that BPA has performed some kind of analysis. . . . ," B-CB-01, 4, or presumes - "[p]resumably, the analysis performed during bid preparation, ." id., 5, that such analysis exist. CBI's assumptions and presumptions that better information may exist are not sufficient to outweigh the evidence of BPA's loads and revenues that are in the record. CBI cannot at this late stage assert that there has been a failure to produce load and resource, revenue requirement, and revenue forecast analyses regarding the proposals when they failed to request them earlier and only assume or presume that they do exist.

CBI asserts that the decision in this case may be arbitrary, capricious, an abuse of discretion or otherwise not in accordance with law because of the lack of such information. CBI Br., supra, 7. As described, supra, however, the record contains sufficient probative evidence to support the Administrator's decision. CBI filed a motion to compel production of certain proposals, and had the opportunity to move to compel production of the analyses it asserts are missing. The Hearing Officer denied CBI's motion. WP-95-O-10 The record contains sufficient evidence to support the Administrator's rate decision without any proposal analysis.

***Decision***

*There is sufficient probative load, revenue, and revenue forecast evidence in the record to support the Administrator's decision without the load and resource, revenue requirement and revenue forecast analyses supporting surplus firm offers, if any, sought by CBI.*

### 4.1.3.3 Compliance With Procedural Orders in the Rate Proceeding

***Issue***

*Whether the Hearing Officer correctly concluded that CBI's failure to serve parties with its Data Requests excused BPA from responding to the Data Requests.*

**Parties' Positions**

The DSIs objected to CBI's Data Requests on the grounds that CBI had failed to make timely service of the requests on parties to the rate case, see DSI Objections to Data Requests, WP-95-M-11, and that therefore BPA should be relieved of any obligation to respond. Id.

CBI stated that it filed Data Requests on May 9, 1995, with BPA. WP-95-M-13, 12. CBI "did not serve the rejected data requests immediately, but submitted amended data requests to BPA on May 12. . . ." Id. CBI served its amended data requests to the parties on the service list by mail on May 16, 1995. Id. CBI argued that the DSIs objections were moot, CBI Motion to Compel, supra, 12, and that the DSIs should have asked CBI's attorney to fax the data requests instead of filing objections. Id., 13.

**BPA's Position**

BPA took no position on the DSI's objection.

**Evaluation of Positions**

The DSIs asserted that CBI's failure to timely serve copies of CBI's Data Requests, which included Data Requests CBI/BPA 33-38 which specifically addressed negotiations with DSIs, harmed the DSIs. DSI Objections, supra, 3. The DSIs cited Rule 1010.8 of the Procedures Governing BPA Rate Hearings that data requests "shall be served on all parties to the service list compiled by the hearing officer." Id., 2. They also cited Rule 4 of the Order on Procedures for Data Requests, WP-95-O-03, which provides that "[o]ne copy of each data request must be served upon each of the other parties' representatives on the Official Service List established by the Hearing Officer." Id. The DSIs argued that BPA should be relieved of any obligation to respond. Id., 3.

CBI stated that it filed Data Requests on May 9, 1995, with BPA. CBI Motion to Compel, supra, 12. BPA objected to the form of the requests. CBI "did not serve the rejected data requests immediately, but submitted amended data requests on May 12. . . ." Id. CBI served its amended data requests on parties on the service list by mail on May 16, 1995. Id. The amended data requests were substantively identical to the earlier set that had not been served on all parties. CBI argued that the DSIs objections were moot, id., 12, and that the DSIs should have asked CBI's attorney to fax the data requests instead of filing objections. Id., 13.

The schedule adopted by the Hearing Officer allowed BPA and parties only 7 days to respond to data requests. Order on Data Request Procedures, WP-95-O-03, 3. This rate case was conducted as an expedited proceeding pursuant to BPA's Procedures Governing Bonneville Rate Hearings, section 1010.10. CBI was aware of the expedited schedule in WP-95, see Order Establishing Schedules, WP-95-O-05, and of the importance of following service rules in a timely manner so that litigants might respond quickly to filed material. Although BPA took no position on the DSI's objections, and, in fact answered the data requests in the time allowed, the DSIs stated they were harmed by CBI's failure to make timely service. In view of the expedited schedule, not only the DSIs but others as well could have been deprived of an opportunity to object to the data requests by CBI's failure to provide them to all parties on time. The Hearing Officer was correct in granting the relief sought by the DSI's.

***Decision***

*The Hearing Officer's order to relieve BPA of any obligation to respond further to CBI's was justified. This moots CBI's claim that it was prejudiced by BPA's refusal to provide it information that BPA claimed was confidential or predecisional..*

**4.2 Settlement Agreement**

***Issue***

*Whether the Settlement Agreement eliminated the Administrator's ability to adjust rates to match costs or otherwise constrains the Administrator's discretion to determine final rates based on the record of this section 7(i) proceeding.*

**Parties' Positions**

CBI asserts that by signing the Settlement Agreement BPA "agreed to increase rates in FY 1996 by no more that 4 percent," WP-95-E-CB-01, 3; that BPA "sign[ed] away its ability to meet its statutory requirements to cover its costs in FY 1996," id; and that BPA's initial filing was a "prejudged conclusion arising from the improvident Settlement Agreement," WP-95-B-CB-01, 6. The gravaman of CBI's position is that the Administrator predetermined his final decision in this rate proceeding, and precluded himself from reaching any other decision based on the record developed in the proceeding, when BPA

signed the Settlement Agreement, in violation of the statutory requirement that the Administrator make a final decision establishing a rate or rates based on the record developed as part of the section 7(i) rate case. Northwest Power Act, § 7(i)(5).

**BPA's Position**

By signing the Settlement Agreement, the Administrator neither predetermined his final decision, nor precluded himself from reaching a final decision different from the initial proposal.

Furthermore, the Settlement Agreement itself, which is a part of this record at Attachment B of WP-95-E-BPA-13, states at the first numbered paragraph that: "Proposal. This document represents an agreed upon proposal for BPA's 1995 rate proceeding and the Administrator's final decision must be supported by and made based on the rate case record." This is an unambiguous expression of the parties intent and understanding that BPA agreed only to make a certain initial proposal, but that the final decision of the Administrator could only be made upon the record that subsequently would be developed in the section 7(i) rate proceeding.

**Evaluation of Positions**

The record makes clear that by signing the Settlement Agreement the Administrator did not predetermine his final decision, or in any way preclude himself from making a final decision different from the proposed settlement. CBI offers no evidence for its position other than the allegation that by executing the Settlement Agreement BPA precluded the Administrator from basing his decision on the record. CBI's position is not supported by the plain language of the Settlement Agreement itself, which unambiguously states that the Administrator's final decision would be based only on the rate case record. Further, CBI's position is contradicted by rebuttal testimony that makes clear that the parties to the Settlement Agreement were appraised during settlement negotiations, and that it was BPA's position that BPA was agreeing to make a proposal only. Moorman, WP-95-E-BPA-21, at 2-4.

In rebuttal testimony, BPA stated that in the negotiations that preceded the execution of the Settlement Agreement, BPA's lead negotiator and Group Vice President for Marketing, Conservation, and Production, Mr. Walter Pollock, "clearly stated that BPA could agree only to make a rate proposal. Mr. Pollock observed that the settlement must be introduced into the record of the rate case, that the Administrator must make his final decision based on the rate case record, and that until the record is closed, the Administrator simply cannot prejudge the outcome of the case by a settlement." Id..

***Decision***

*The Administrator did not predetermine his final decision, nor was he precluded by the Settlement Agreement from making a final decision different from the initial proposal of a 4 percent surcharge.*

## 4.3 Waivers and SP Contracts

### 4.3.1 Appropriateness of Rate Case Review of Contracts

***Issue***

*Whether the waivers coupled with follow-on contracts for sales of power at different rates to the same customers constitutes ratemaking through contract and must be on the record of this proceeding.*

**Parties' Positions**

CBI argues that BPA's granting of the waivers to its customers and its subsequent negotiations for sales of power to the same customers constitute private rate cases that must be on the record of this proceeding. CBI, Br., B-CB-01,10. Citing PGE v. Johnson, 754 F.2d 1475 (9th Cir. 1985), CBI asserts that when BPA offers to sell power to a class of customers at a rate unavailable to that class under the established rate structure, it has modified the rate structure and must follow statutory ratemaking procedures. Id.

No other party has commented on this issue.

**BPA's Position**

The waivers and subsequent negotiations for sales of power do not constitute ratemaking and do not need to be on the record. WP-95-M-15, 4. BPA's offers of power have all been made under the Surplus Firm Power rate schedule, which is available for purchases by both DSIs and public customers. Therefore, BPA has not offered to sell power to a class of customers at a rate unavailable to that class under the established rate structure or otherwise modified the rate structure. Id. of 5.

**Evaluation of Positions**

CBI cites PGE v. Johnson, 754 F.2d 1475 (9th Cir. 1985), for the proposition that the waivers and subsequent negotiations for sales of power constitute ratemaking. In PGE, BPA offered to sell power to a class of customers at a rate unavailable to that class under the established rate structure. BPA had long-term power sales contracts with the DSIs under which BPA sold the DSIs power under the Industrial Firm Power rate schedule. BPA then displaced these sales with sales to the DSIs under the Nonfirm rate schedule, which provided that it was "not available for the purchase of energy which BPA has a firm

obligation to supply." PGE, 754 F.2d at 1481. Because BPA had a firm obligation to supply power to the DSIs under their long-term contracts, its sale of nonfirm power to the DSIs was inconsistent with the availability provision of the nonfirm rate schedule. BPA was offering to sell power to a class of customers at a rate unavailable to that class under the established rate structure.

That is not the case with the waivers and subsequent negotiations. BPA's offers have been made under the Surplus Firm Power rate schedule, which is available "for the purchase of Surplus Firm Power for the period ending September 30, 1998." See Schedule SP-93, Sec. 1. This rate schedule is available to all customers to which BPA has made offers, and CBI has made no contention to the contrary. Therefore, BPA has not changed the availability provisions of the rate schedule or offered to sell power to a class of customers at a rate unavailable to that class under the established rate structure. Instead, BPA has simply offered to sell power to customers in conformance with an existing rate schedule. This course of action does not constitute ratemaking.

In California Energy Commission v. BPA, 754 F.2d 1470 (9th Cir. 1985), which CBI also cites, BPA sold power to two utilities at a rate that had not been established in any rate schedule. The court concluded that such a sale ordinarily would require modification of the rate schedule through statutory ratemaking procedures. The Surplus Firm Power rate schedule at issue here provides for a flexible rate as agreed between BPA and the customer. Schedule SP-93, sec. II(B). Therefore, BPA's offers comply with the rate schedule.

***Decision***

*The waivers and subsequent sales of power and negotiations for power sales do not constitute ratemaking and do not need to be on the record in this proceeding.*

### 4.4 Environmental Analysis

#### 4.4.1. Introduction

A Notice of Availability of the Business Plan Draft Environmental Impact Statement (EIS) was published in the Federal Register on July 8, 1994, and was circulated to interested persons, including most parties in this rate proceeding, for review and comment by August 22, 1994. Environmental Impact Statements; Notice of Availability, 59 Fed. Reg. 35119 (1994). The comment period was extended to September 9, 1994. Within the Business Plan Draft EIS, BPA stated that the EIS was intended to support, inter alia, rates for BPA products and services to be implemented in the 1995 rate case and future rate cases. See Business Plan Draft Environmental Impact Statement (DEIS), WP-95-EV-01. In the February 14, 1995, Federal Register notice announcing BPA's 1995 wholesale power and transmission rate increase, BPA further explained that the potential environmental impacts of the proposed wholesale power and transmission rate increases and alternatives thereto would be evaluated, pursuant to the National Environmental Policy Act (NEPA), as part

of the Business Plan EIS. See Proposed Wholesale Power rate Adjustment, Public Hearing, and Opportunities for Public Review and Comment, 60 Fed. Reg. 8498, 8507, and 8508 (1995). The Federal Register notice also noted that all comments on the Business Plan EIS would be received as part of the NEPA review process, outside of the formal rate proceeding. Id.

Because of a number of factors, including substantial changes to BPA's business environment, additional policy choices, and public comments received on the Business Plan Draft EIS identifying fundamental issues, BPA decided to prepare a Business Plan Supplemental Draft EIS. See Business Plan Supplemental Draft Environmental Impact Statement, Vol. 1 - Analyses, WP-95-EV-02; and Business Plan Supplemental Draft Environmental Impact Statement, Vol. 2 - Appendices, WP-95-EV-03. A Notice of Availability of the Business Plan Supplemental Draft EIS was published in the Federal Register on March 17, 1995, and the comment period ended May 1, 1995. Environmental Impact Statements; Notice of Availability, 60 Fed. Reg. 14431, 14433 (1995). BPA issued a Business Plan Final EIS, and published a Notice of Availability in the Federal Register on June 23, 1995. Environmental Impact Statements; Notice of Availability, 60 Fed. Reg. 32671 (1995). The Business Plan Final EIS includes BPA's responses to all public comments on the various Business Plan EIS documents. The Business Plan EIS documents are included as part of the official record of the 1995 Final Rate Proposal. See Business Plan Draft Environmental Impact Statement, WP-95-EV-01; Business Plan Supplemental Draft Environmental Impact Statement, Vol. 1 - Analyses, WP-95-EV-02; Business Plan Supplemental Draft Environmental Impact Statement Vol. 2 - Appendices, WP-95-EV-03; Business Plan Final Environmental Impact Statement, Vol. 1 - Analyses (FEIS), WP-95-EV-07; Business Plan Final Environmental Impact Statement, Vol. 2 - Appendices (Appendices), WP-95-EV-08; and Business Plan Final Environmental Impact Statement Summary (Summary), WP-95-EV-09.

### 4.4.2. NEPA Analysis

**Issue**

*Whether BPA adopted the Settlement Agreement and granted contract waivers without complying with NEPA.*

**Parties' Position**

CBI maintains that BPA's NEPA violations in this proceeding are numerous and profound. CBI Br., WP-95-B-CB-01, 14. CBI claims that BPA prepared no EIS, no Environmental Assessment (EA), and no Finding of No Significant Impact (FONSI) on the terms in this rate case. Id., at 12. CBI then states that BPA's reliance on the Business Plan EIS for environmental guidance is misplaced. Id.

In addition, CBI maintains that BPA granted waivers and negotiated contracts, substantially reducing the rates for the power provided under them, in a manner which was

never considered in an EIS or in any other environmental document. Id. CBI asserts that NEPA places a duty on BPA to evaluate the environmental consequences and alternatives to the (re)negotiated terms of such major federal action. Id. Moreover, CBI contends that BPA agrees that NEPA requires the preparation of an EIS when a BPA action may affect the environment. Id., at 13.

**BPA's Position**

BPA establishes or revises its wholesale power and transmission rates to recover its costs in accordance with sound business principles pursuant to a formal rate hearing process required by section 7(i) of the Northwest Power Act. 16 U.S.C. § 839e(a)(1). BPA prepares an initial rate proposal and convenes a hearing in which a record is developed and public comments on the proposed rates are received. 16 U.S.C. § 839e(i). After such hearing, the Administrator makes a final decision on the proposed rates. Id. In this case BPA's initial rate proposal consisted of the 4 percent increase to its adjustable rates, consistent with the terms of the Settlement Agreement. Moorman, WP-95-E-BPA-13, 15-18, and Attachment B. On March 16, 1995, BPA considered the question whether NEPA review was required for the Settlement Agreement. BPA determined that NEPA was not triggered since the Settlement Agreement resulted in an initial rate case proposal and not a final action. See WP-95-EV-07. The Administrator makes a final decision on the proposed rate increase as part of the record of decision on the final rate proposal. 16 U.S.C. § 839e(i)(5).

BPA prepares an environmental review of its rate proposal in an appropriate NEPA review document which is outside of the formal rate process. Proposed Wholesale Power rate Adjustment, Public Hearing, and Opportunities for Public Review and Comment, 60 Fed. Reg. 8498, 8507, 8508 (1995). BPA may prepare an EIS or an EA/FONSI, or it may categorically exclude a rate proposal from either an EIS or an EA, as appropriate. 10 C.F.R. § 1021.300. The BPA Business Plan Final EIS provides the analysis for understanding the environmental consequences of BPA's 1995 final rate proposal to surcharge each component of BPA's adjustable rates by 4 percent for the rate period October 1, 1995, through September 30, 1996. The knowledge and experience that BPA has developed and accumulated through the years from rate-related environmental analyses, including the 1993 Wholesale Power and Transmission Rate Adjustment Final Environmental Assessment (DOE/EA-0838, July 1993), were incorporated by reference into the Business Plan Final EIS, which provides additional analysis. See FEIS, WP-95-EV-07, at Chapter 4; and Appendices, WP-95-EV-08, at Appendix B. This information was then used to inform the decision maker of how the rate-related business decisions made by BPA may affect the human environment.

**Evaluation of Positions**

CBI erroneously alleges that BPA has made "numerous and profound violations of NEPA." CBI Br., WP-95-B-CB-01, 14. First, CBI claims that BPA relied on no NEPA analysis to support this rate case. Id., at 13. BPA disagrees with CBI's assertion that

there is no NEPA review document to support the 1995 final rate proposal. BPA determined that NEPA review was not triggered at the time of the Settlement Agreement since it resulted in an initial rate case proposal and not a final action. WP-95-EV-07. The Administrator's final decision on the 1995 rate proposal is made after the hearing and is based on the record, which includes the hearing transcript, exhibits, and material and information submitted to or developed by the Administrator. 16 U.S.C. § 839e(i)(5). In addition to the materials filed in the hearing, BPA relied on the Business Plan Final EIS for an understanding of the environmental consequences of BPA's 1995 final rate proposal to surcharge each component of BPA's adjustable rates by 4 percent for the rate period October 1, 1995 through September 30, 1996. FEIS, WP-95-EV-07, passim.; and Appendices, WP-95-EV-08, at Appendix B.

CBI asserts that BPA's reliance on the Business Plan EIS for environmental guidance is misplaced. WP-95-B-CB-01, 12. CBI's Initial Brief, however, makes no argument to support this assertion. Procedures Governing Bonneville Power Administration Rate Hearings, 51 Fed. Reg. 7611, § 1010.14 (1986). BPA considered all public comments on the Business Plan Draft EIS and Business Plan Supplemental Draft EIS, including comments on sections pertaining to BPA's rates. Its responses to the comments are included in the Business Plan Final EIS documents. Appendices, WP-95-EV-08, Appendix E and Appendix F. BPA has determined that the Business Plan Final EIS does evaluate the environmental impacts of the 1995 final rate proposal and that reliance upon this document is not misplaced.

The analysis in the Business Plan Final EIS shows that it is the market responses (resource development and operations, transmission development and operations, and consumer behavior) to BPA's proposed rate increase which may lead to environmental impacts. FEIS, WP-95-EV-07, at Chapter 4, section 4.2.2. The proposal to increase BPA's adjustable rates by 4 percent is an action that falls within the Status Quo alternative that is described and evaluated as part of the Business Plan Final EIS. Id., section 2.2. The Status Quo alternative is identified as an environmentally preferred alternative in the Business Plan Final EIS. Summary, WP-95-EV-09, at S-7. Furthermore, the proposal for a 4 percent increase to BPA's existing wholesale power and transmission rates for a 1-year period will not lead to construction of new regional resources, changes in resource operations, or alterations to the development and operation of transmission facilities. In addition, it will not significantly modify consumer behavior. FEIS, WP-95-EV-07, at section 4.4. Accordingly, BPA's 1995 final rate proposal does not necessitate the implementation of any mitigation measures.

CBI also claims that BPA granted waivers and negotiated contracts, which reduced rates for the power provided under them, in a manner that has never been considered in an EIS or any other environmental document. CBI Br., WP-95-B-CB-01, 12. BPA's decisions to grant waivers and negotiate separate contracts were not decisions to be made by the Administrator as part of this Record of Decision for the 1995 Final Rate Proposal. These decisions were supported by separate NEPA review documents. See WP-95-EV-04; and WP-95-EV-05.

***Decision***

*The Settlement Agreement resulted in an initial rate case proposal providing for a 4 percent increase to BPA's adjustable rates for the 1-year rate period and not a final action. The environmental analysis provided by the Business Plan Final EIS details the environmental impacts of the proposal to increase BPA's adjustable rates by 4 percent and is considered by the Administrator as part of the final decision to adopt the proposed rates. Finally, the decisions to grant waivers and negotiate contracts are not decisions to be made by this Record of Decision. These decisions were supported by separate NEPA review documents.*

# 5.0 PARTICIPANTS COMMENTS

## 5.1 Introduction

This chapter addresses the comments of participants in BPA's 1993 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 and are fully considered by the Administrator in making his final decision.

The participants' portion of the Official Record consists of the transcripts of 1 field hearing held in Eugene, Oregon on June 6, 1995, at which 9 persons presented their comments. The field hearing was transcribed and the transcription is part of the Official Record. BPA also received 2 pieces of correspondence related to the rate filing during the public comment period, which officially ended June 9,1995. These comments also became part of the Official Record. The names of the participants that commented on BPA's rate proposals are listed in 5.4.

BPA reviewed the participants' portion of the record and identified the concerns expressed by the participants to be addressed in this chapter of the ROD. Below is a summary of the testimony provided at the field hearings and the letters that BPA received during the comment period, along with BPA's responses to those concerns.

Copies of the comments of participants and letters received after the comment period are available for inspection in BPA's Public Reference Room.

## 5.2 Field Hearings and Initial Proposal Comment Period

A total of 9 persons provided testimony at the field hearing with approximately 50 persons attending. During the Initial Proposal Comment Period, which closed June, 9, 1995, 2 letters were also received. One letter, from the Public Power Council (PPC) and Direct Services Industries, Inc. (DSIs), was subsequently attached to testimony submitted by PPC E-PP-01, Attachment 3. The issues raised in that letter are not addressed individually here. The following represent other issues that were raised

Following is a summary of comments received on the 1995 rate proposal.

## RATE INCREASE

**COMMENT SUMMARY**: BPA does not need the four percent rate increase and should take steps to insure that its rates remain competitive, including recovering stranded investment.

**RESPONSE**: BPA and its most parties to the 1995 rate proceeding agreed that BPA should propose to raise its rates 4 percent beginning October 1, 1995. Several years of drought and costs outside of BPA's control, such as costs to mitigate and enhance fish and wildlife in the region, have caused BPA's financial reserves to be reduced to a point where Treasury repayment could be at risk. The customers recognized BPA's need to rebuild reserves and to continue to pay for fish and wildlife programs, and agreed in March 1995 to a proposed rate increase of 4 percent.

BPA is in the process of cutting costs. BPA is required by statute to mitigate and enhance fish and wildlife resources in the region. The solution for the short term is being implemented by means of the stipulated settlement between BPA and its customers to increase rates by 4 percent for 1 year beginning October 1995. For the longer term, whether and how BPA should attempt to make customers who leave pay for stranded investment will be addressed in a separate rate case unless it can be resolved sooner through a separate process involving discussions with its customers and other interested parties.

**COMMENT SUMMARY**: Concern was expressed about a report that BPA's FY 1995 first quarter costs were $55 million greater than FY 1994 first quarter costs.

**RESPONSE**: Unaudited actual operating expenses for the first quarter of FY 1995 were $55 million higher than those for the first quarter of FY 1994. By the second quarter, the actual expenses had been reduced to $47 million over the similar FY 1994 period. The forecast for the remainder of FY 1995 shows that BPA is on track to reduce its costs even further.

**COMMENT SUMMARY**: How will retail ratepayers of BPA's power customers be affected by the four percent rate increase?

**RESPONSE**: The impact on retail ratepayers will depend on how much of the four percent surcharge the purchasing utility decides to pass on to its customers.

**COMMENT SUMMARY**: If BPA did not have workshops, studies, forecasts, risk analysis, mailers, and handouts, it would save so much money that a rate increase would not be necessary.

**RESPONSE**: BPA is required by the Northwest Power Act to conduct a public involvement process each time we propose new rates. In addition, workshops, handouts

and other public mailings are designed to respond to customer and public requests for information regarding how we set our rates. Because BPA is a government agency, we are required to respond to requests for information and to be open about our ratesetting processes. As noted by Mr. DeWolf at page 69 of WP-95-TB-01, the cost increases BPA needs to recover for FY 1996 (the effective period of the 4 percent increase) are primarily due to BPA's need to rebuild financial reserves and the increasing costs of fish and wildlife programs. Public involvement expenses are a relatively small part of BPA's revenue requirement.

## RATE DESIGN

**COMMENT SUMMARY**: A Commenter expressed disappointment that after spending much time and expense on developing tiered rates, BPA has decided not to use them and is proposing a four percent rate increase instead.

**RESPONSE**: During the time tiered rates were being developed, the wholesale price of electricity was falling dramatically. By the time BPA was preparing to release the rate proposal, with tiered rates, it was obvious that the price of "Tier 2" power was above where the market was. In addition, BPA customers were beginning to receive longer-term offers from suppliers (that is, longer than the 2 year rates that BPA has offered since the early 1980s). Finally, tiered rates were inordinately complex, making them a competitive liability. In response to these market forces, BPA decided that tiered rates, as designed, would not work, and that BPA needed to offer a 5-year rate term. BPA needed more time to prepare this initial proposal, so entered into settlement discussions with the rate case parties. This settlement, resulting in the proposed 4 percent surcharge, gave BPA the needed time to prepare the 1996 initial proposal. The 4 percent surcharge is necessary for the October 1995 - September 1996 rate period to ensure BPA covers all of its financial obligations.

**COMMENT**: BPA should not eliminate the low density discount in the 5-year rate case. If it did, this would make it possible for private sector utilities to compete with BPA to sell power to Emerald PUD.

**RESPONSE**: The Low Density Discount is offered to customers through a provision of the Northwest Power Act. BPA does not propose elimination of the Low Density Discount in the 1995 rate case nor the proposed 1996 rate case. BPA, however, is proposing changes to the eligibility criteria of the Low Density Discount as part of its 1996 Initial Proposal. The discount is proposed to be capped at 7 percent and would apply only to power purchases.

## NUCLEAR PROJECTS

**COMMENT SUMMARY**: Several Commenters expressed concern about BPA's involvement in the WPPSS Nuclear program. Commenters claim that the nuclear project costs outweigh BPA's fish costs and suggest that participants in the project be required to continue paying for the projects if the participant leaves BPA as a power supplier.

**RESPONSE**: BPA's participation in the WPPSS projects is an historical fact and is beyond the scope of this rate proceeding. Along with other cost cutting measures, BPA has taken steps to reduce WPPSS costs. BPA expects fish costs to exceed WPPSS debt service in the next few years. As noted above, stranded investment issues will be discussed in conjunction with the 1996 rate proceeding.

**COMMENT SUMMARY**: How many dollars in the four percent rate proposal are included for the decommissioning and the shutdown of the Trojan plant?

**RESPONSE**: $9.9 million of the 1995 revenue requirement is $2,662 million is for Trojan costs. This amount includes debt service, as well as decommissioning costs.

## FISH AND WILDLIFE PROGRAM

**COMMENT SUMMARY**: Several commentors asked whether BPA had enough budgeted long-term to meet the needs of future generations, including enough money to pay for the increasing costs of salmon recovery and to promote energy conservation and renewable resources.

**RESPONSE**: BPA is aware of its unique public mission and is striving to manage its costs, including reducing planned annual expenditures for the year 1996 through 2000 by approximately $500 million per year when compared to the 1995 Congressional Budget submission. Unlike its competitors, BPA provides unique benefits to the region, including a statutory responsibility to protect and enhance fish and wildlife resources and to act as the guardian of an international river. BPA is holding is rates a low as possible in order to remain competitive in an ever increasing market for wholesale electric power. If we do less, customers will leave the BPA system, revenues will drop, putting the future funding of BPA programs, such as conservation and fish and wildlife at risk. BPA can retain load and sustain its revenues by providing products and services customers want at terms and prices they find attractive. BPA's 1995 rate proposal provides adequate revenues for BPA to recover its costs while, at the same time giving the agency time to develop a 2- and 5-year rate proposal that will meet market conditions and ensure the continued success of BPA and its customers well into the 21st century.

## ALUMINUM INDUSTRIES

**COMMENT SUMMARY**: The variable rate for aluminum companies is a large subsidy by other ratepayers.

**RESPONSE**: Some people do have the perception that the aluminum industry is being subsidized by other BPA ratepayers. This perception is incorrect. The rate to the aluminum companies and the other direct service industries (DSIs) is based on specific rate directives contained in the Northwest Power Act. BPA has developed a ratemaking methodology that complies with these and the other rate directives contained in the Northwest Power Act. The perception of a subsidy arises when one views certain intermediate rate design steps without considering the overall methodology that determines the DSI rates. Viewing only these steps leads to the mistaken impression that BPA is subsidizing the DSIs.

The current variable rate has been approved by the Federal Energy Regulatory Commission (FERC) for a total of 10 years, beginning on August 1, 1986, and terminating on June 30, 1996. The variable rate was designed to ensure that BPA would receive revenues equal to or greater than revenues expected if the Industrial Firm Power (IP) rate were the effective rate to the aluminum companies. Although the rate to the aluminum companies decreases when aluminum prices are low, it increases when aluminum prices are high, as they are now. During much of the time that the variable rate has been in effect, the aluminum companies paid more than they would have under the IP rate.

BPA has estimated that for the 10-year period the variable rate will be in effect, it will have generated more revenues than the IP rate would have generated. This benefits *all* of BPA's ratepayers and demonstrates that the variable rate has not been a subsidy to the aluminum companies. Furthermore, the only changes contained in the 1995 rate proposal to the approved variable rate are a 3-month extension and a waiver of the biennial adjustment to the lower rate limit. BPA projects that neither of these changes will affect either the rate to the aluminum companies or the revenues that BPA would have received if the aluminum companies were charged the IP rate.

Furthermore, the suggestion that BPA curtail first and second quartile power and sell the power elsewhere at a higher price is inappropriate. First, although BPA does have certain flexibility to restrict the first quartile, BPA cannot restrict the second quartile in order to sell the power elsewhere at a higher price. BPA's actions are governed by the Power Sales Contract it entered into with the DSIs in 1981. In addition, it would not be in BPA's or the region's best interests to cut off power from the DSIs in order to seek other customers. Finally, the commenter assumes that if BPA did sell the power elsewhere, it

could realize a higher price. In today's competitive wholesale power market, this assumption is questionable.

## COMPETITIVENESS AND BPA MISSION

**COMMENT SUMMARY**: Concern was expressed that in BPA's drive to be competitive the agency neglect its legislative purpose. BPA has to balance the need to be competitive with the need to pursue its mission, to serve the people of the Northwest. Concern was also expressed that the change to the "new BPA" has been unsuccessful and wasteful.

**RESPONSE**: This comment is outside the scope of the 1995 rate proposal. BPA does not intend, however, to neglect its statutory requirements. In fact, one of the major reasons BPA is redesigning itself as a competitive business is to sustain a sufficient level of revenue so that we can support programs such as fish and wildlife mitigation and enhancement. We recognize, however, that dealing with BPA in a time of transition is not easy. BPA is redesigning itself and its business relationships in response to intense market competition and a rapidly changing power market. BPA has been faced with what has seemed like an endless stream of challenges unparalleled in the history of the Northwest: drought, deregulation, increased costs for fish recovery and huge amounts of generation debt service. BPA chose to use these events as reasons to change and take the challenges head-on. We are taking risks and trying new ways of being and doing, and we will make mistakes in the short run. In the long run, however, we intend to be a reliable business partner, a competitive marketer of power and transmission products and services, and a socially responsive citizen of the Northwest.

**COMMENT SUMMARY**: Concern was expressed about BPA as a reliable business partner, although the account executive program was labeled as a "resounding success."

**RESPONSE**: This is outside the scope of the 1995 rate proposal, although BPA appreciates feedback from its customers and is in the process of redesigning its business relationships and products and prices that will convince customers of BPA's sincerity in becoming a competitive, as well as reliable and trustworthy, supplier of power and transmission products and services. We appreciate the perception of success and related vote of confidence in one of the major changes we have made in the way BPA operates.

### 5.3 List of Participants

Public Power Council/Direct Services Industries, Inc.
Mrs. B. Porter
Commenters at field hearing held at Emerald Public Utility District, June 6, 1995:

Richard Eymann, Emerald PUD Board Director
Jim Brown, Member, Emerald PUD Board
Jeff Shields, Manager, Emerald PUD
Bob Wittenburg
Ron Davis
Doug Still, Director, Emerald PUD
Hall Conner

## 6.0 CONCLUSION

As required by law, the rates established and adopted in this ROD have been set to recover 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 (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and all other costs and expenses incurred by the Administrator 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 BPA's power, to equitably allocate the recovery of transmission costs between Federal and non-Federal users, and to satisfy BPA's other ratemaking obligations. The hearing officer has assured that all interested parties and participants were afforded the opportunity for a full and fair evidentiary hearing, as required by law.

BPA must evaluate the proposed rate increases in a section 7(i) proceeding pursuant to the Northwest Power Act. BPA must also evaluate the potential environmental impacts of the proposed rate increases and alternatives thereto, as required by NEPA. In this instance, the environmental analysis provided by the Business Plan Final EIS details the environmental impacts of BPA's 1995 final rate proposal. The environmental analysis contained in the Business Plan Final EIS has been considered in making the decision below.

Based upon the record compiled in this proceeding, the decisions expressed herein, and all requirements of law, I hereby adopt the attached Wholesale Power and Transmission Rate Schedules as final Bonneville Power Administration rates. In accordance with Federal Energy Regulatory Commission Requirements, 18 C.F.R.section 300.10(g), the Administrator hereby certifies that the Wholesale Power and Transmission Rate Schedules adopted herein are consistent with applicable laws and are the lowest possible rates consistent with sound business principles.

Issued at Portland, Oregon, this 28th day of July, 1995.

Jack Robertson
Acting Administrator

# APPENDIX A

# WHOLESALE POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

# WHOLESALE POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

## TABLE OF CONTENTS


| Wholesale Power Rate Schedules | | Page |
|---|---|---|
| PF-95 | Priority Firm Power Rate | A-1 |
| IP-95 | Industrial Firm Power Rate | A-8 |
| VI-95 | Variable Industrial Power Rate | A-12 |
| SI-95 | Special Industrial Power Rate | A-18 |
| CE-95 | Emergency Capacity Rate | A-21 |
| NR-95 | New Resource Firm Power Rate | A-23 |
| NF-95 | Nonfirm Energy Rate | A-29 |
| SS-95 | Share-the-Savings Energy Rate | A-34 |
| PS-95 | Power Shortage Rate | A-36 |
| RP-95 | Reserve Power Rate | A-39 |

**General Rate Schedule Provisions**

| | | |
|---|---|---|
| Section I | Adoption of Revised Rate Schedules and General Rate Schedule Provisions | A-44 |
| Section II | Types of BPA Service | A-44 |
| Section III | Billing Factors and Billing Adjustments | A-47 |
| Section IV | Other Definitions | A-59 |
| Section V | Application of Rates Under Special Circumstances | A-66 |
| Section VI | Billing Information | A-68 |
| Section VII | Variable Industrial Rate Parameters and Adjustments | A-72 |

## Schedule PF-95
# 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 startup, 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, 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-93, which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions (GRSPs).

## 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. 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. $4.307 per kilowatt of billing demand occurring during all Peak Period hours during a billing month.

b. No demand charge during Offpeak Period hours during a billing month.

#### 2. Energy Charge

a. 23.06 mills per kilowatt-hour of billing energy for the billing months September through March.

b. 16.94 mills per kilowatt-hour of billing energy for the billing months April through August.

**B. Exchange Rate**

**1. Demand Charge**

a. $4.307 per kilowatt of billing demand occurring during all Peak Period hours during a billing month.

b. No demand charge during Offpeak Period hours during a billing month.

**2. Energy Charge**

a. 23.06 mills per kilowatt-hour of billing energy for the billing months September through March.

b. 16.94 mills per kilowatt-hour 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) 76 percent of the Measured Energy (excluding unauthorized increase); and

(2) 24 percent of the Computed Energy Maximum.

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

(1) 63 percent of the Measured Energy (excluding unauthorized increase); and

(2) 37 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 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 4.90 mills per kilowatt-hour, to the charges for qualifying energy purchased under this rate schedule. The irrigation discount shall be applied after calculation of the LDD. 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.6 of the GRSPs and subsequent to any other rate adjustments.

## E. 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.

## F. 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

a. 100.00 mills per kilowatt-hour during the billing months August through March.

b. 57.40 mills per kilowatt-hour during the billing months April through July.

### 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:

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

(b) 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:

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

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

## G. 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.5 of the GRSPs. Computed requirements purchasers are not subject to the Coincidental Billing Adjustment for scheduled power.

## 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 billing demand and computed average energy requirement

for the billing month shall be subject to the following surcharge for each additional kilowatt-hour so returned:

1. 4.25 mills per kilowatt-hour for the months of April through October;

2. 1.80 mills per kilowatt-hour 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-95 rate is 72.2 percent FBS and 27.8 percent Exchange.

**B.** The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

**C.** The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

## Schedule IP-95
## 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-95 rate schedule is available for that portion of power purchased not covered under the alternative rate schedule. This rate schedule supersedes Schedule IP-93, which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions (GRSPs).

**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 First Quartile Service.

**A. Demand Charge**

1. $5.316 per kilowatt of billing demand occurring during all Peak Period hours during a billing month.

2. No demand charge during Offpeak Period hours.

**B. Energy Charge**

1. 21.90 mills per kilowatt-hour of billing energy for the billing months September through March.

2. 18.02 mills per kilowatt-hour 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 GRSPs. If BPA has agreed to serve a portion of a DSI load under an alternative rate schedule, the billing demand under the IP-95 rate schedule shall be specified in the contract initiating such arrangement.

However, if BPA has agreed, pursuant to section 4 of the DSI power sales contract, to sell Industrial Firm Power on a daily demand basis (transitional service), then 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 kilowatt-hours 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 0.72 mills per kilowatt-hour 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. Unauthorized Increase**

**1. Rate for Unauthorized Increase**

a. 100.00 mills per kilowatt-hour during billing months August through March.

b. 57.40 mills per kilowatt-hour during billing months April through July.

**2. Application of the Charge**

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatt-hours 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.

**D. 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.

**E. Outage Credit**

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-95 rate is 85.8 percent Exchange and 14.2 percent New Resources.

**B.** The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

**C.** The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

## Schedule VI-95
# Variable Industrial Power Rate

## SECTION I. AVAILABILITY

This schedule is available to DSI customers for purchases under the Power Sales Contract implementing the VI rate schedule (Variable Rate Contract) of: (1) Industrial Firm Power; and (2) Auxiliary Power if requested by the DSI customer and made available by BPA. This schedule is available only for that portion of a DSI's load used in primary aluminum reduction including associated administrative facilities, if any. By virtue of incorporation of this rate schedule and associated GRSPs in the Variable Rate Contract, DSIs electing to purchase power under this rate schedule contractually agree to the terms and conditions of this rate schedule. A DSI further agrees to waive, for that portion of their load designated to purchase power at the VI rate, all rights they might otherwise have to purchase power at the Industrial Firm Power Rate Schedule for the duration of the Variable Rate Contract. Sales under this schedule are made subject to BPA's GRSPs.

## SECTION II. TERM OF THE RATE

This rate schedule shall take effect on October 1, 1995, and shall terminate at midnight September 30, 1996.

## SECTION III. RATE

### A. Base Rate

The formula to be used in the calculation of the monthly power bill is contained in section IV. A separate billing adjustment for the value of the reserves provided by 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 Plateau Energy Charge.

#### 1. Base Variable Industrial Rate

a. Demand Charge

$6.233 per kilowatt of billing demand, as adjusted, occurring during the Peak Period during a billing month. No demand charge is applied during Offpeak Period hours.

b. Plateau Energy Charge

18.83 mills per kilowatt-hour of billing energy, as adjusted.

**2. First Quartile Service Discount**

0.59 mills per kilowatt-hour of billing energy.

**3. Lower Rate Limit**

15.03 mills per kilowatt-hour of billing energy.

**4. Upper Rate Limit**

24.63 mills per kilowatt-hour of billing energy.

**B. Base Rate Parameters Subject to Annual Adjustments**

The following base rate parameters shall be used to determine power bills for DSI customers purchasing power under the Variable Rate Contract. These parameters will be adjusted July 1, 1996, in accordance with the procedures contained in section VII.B of the GRSPs.

**1. Lower Pivot Aluminum Price**

75.4 cents per pound.

**2. Upper Pivot Aluminum Price**

91.6 cents per pound.

**SECTION IV. FORMULA**

The Variable Industrial Power rate is a formula rate tied to the U.S. market price of aluminum. Under this rate schedule, the monthly energy charge varies in response to changes in the average price of aluminum in U.S. markets.

**A. Demand Charge**

1. The Demand Charge, as stated in section III.A.1.a of this rate schedule, remains constant over all aluminum prices. The demand charge is applied to billing demand occurring during all Peak Period hours for all billing months.

2. No demand charge during Offpeak Period hours.

**B. Energy Charge**

**1. Plateau Energy Charge**

When the monthly billing aluminum price (described in section VII.A of the GRSPs) is between the Lower Pivot Aluminum Price and the Upper Pivot Aluminum Price inclusive (as stated in sections III.B.1 and III.B.2 of this rate schedule), the monthly energy charge shall be the Plateau Energy Charge as stated in section III.A.1.b of this rate schedule.

**2. Reductions to Plateau Energy Charge**

When the monthly billing aluminum price is less than the Lower Pivot Aluminum Price, the monthly energy charge shall be the greater of:

a. The Plateau Energy Charge - (LP - MAP) * (LS)

where:

LP = the Lower Pivot Aluminum Price as stated in section III.B.1 of this rate schedule.

MAP = the monthly billing aluminum price in cents per pound determined pursuant to section VII.A of the GRSPs

LS = lower slope = $\frac{\text{1 mill per kilowatt-hour}}{\text{1 cent per pound}}$

or

b. the Lower Rate Limit as stated in section III.A.3 of this rate schedule.

**3. Increases to Plateau Energy Charge**

When the monthly billing aluminum price is greater than the Upper Pivot Aluminum Price, the monthly energy charge shall be the lesser of:

a. The Plateau Energy Charge + (MAP - UP) * (US)

where:

MA P = the monthly billing aluminum price in cents per pound, as determined according to section VII.A of the GRSPs.

UP = the Upper Pivot Aluminum Price as stated in section III.B.2 of this rate schedule.

US = upper slope = $\frac{\text{0.75 mills per kilowatt-hour}}{\text{1 cent per pound}}$

b. the Upper Rate Limit, as stated in section III.A.4 of this rate schedule.

## SECTION V. BILLING FACTORS

### A. Billing Demand

**1. Billing Demand for Customers Whose Entire BPA Load is Served at the VI Rate**
The billing demand for power purchased 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 GRSPs.

**2. Billing Demand or Customers When Only a Portion of Their Total BPA Load is Served at the Variable Rate**

The Billing Demand shall be the portion of the BPA Operating Level attributable to the VI rate as determined by the method specified in the Variable Rate Contract.

**3. Billing Demand During Periods of Transitional Service**

If BPA has agreed, pursuant to section 4 of the DSI power sales contract, to sell Industrial Firm Power on a daily demand basis (transitional service), sections V.A.1 and V.A.2 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.

### B. Billing Energy

The billing energy for power purchased shall be the Measured Energy for the billing month, minus any kilowatt-hours on which BPA assesses the charge for unauthorized increase.

## SECTION VI. OTHER ADJUSTMENTS AND SPECIAL PROVISIONS

### A. Lower and Upper Pivot Aluminum Prices

Effective July 1, 1991, and every July 1 thereafter, the Lower and Upper Pivot Aluminum Prices set forth in section III.B of the rate schedule shall be adjusted following the procedures set forth in section VII.B of the GRSPs. The adjusted Lower and Upper Pivot Aluminum Prices shall supersede the Lower and Upper Pivot Aluminum Prices contained in section III.B of the rate schedule.

### B. Discount for Quality of First Quartile Service

If a purchaser requests First Quartile service with other than Surplus Firm Energy Load Carrying Capability (FELCC), a discount contained in section III.A.2 of this rate schedule shall be granted. This billing credit shall be applied to the monthly billing energy under section V.B for all power purchased under this rate schedule. No credit shall be applied to those purchases subject to unauthorized increase charges under section VI.F of this rate schedule. 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 Rate Contract. Such acceptance includes the waiver of contract rights provided in section 6.a(2)(a) of said contract.

### C. Unauthorized Increase

#### 1. Rate for Unauthorized Increase

a. 100.00 mills per kilowatt-hour during the billing months August through March.

b. 57.40 mills per kilowatt-hour during the billing months April through July.

#### 2. Application of the Charge

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatt-hours 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.

### D. 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 BPA Operating Level 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.

**E. Outage Credit**

Pursuant to section 7 of the General Contract Provisions, BPA shall provide an outage credit to any DSI to whom 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 VII. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

**A.** The approximate cost contribution of different resource categories to the VI-95 rate is 85.8 percent Exchange and 14.2 percent New Resources.

**B.** The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

**C.** The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

## Schedule SI-95
# 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. Schedule SI-95 supersedes schedule SI-93, which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions (GRSPs).

## SECTION II. RATE

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 Special Industrial Power Rate charges.

### A. Demand Charge

1. $3.827 per kilowatt of billing demand occurring during all Peak Period hours during a billing month.

2. No demand charge during Offpeak Period hours.

### B. Energy Charge

1. 21.20 mills per kilowatt-hour of billing energy for the billing months September through March;

2. 15.08 mills per kilowatt-hour of billing energy for the billing months April through August.

## SECTION III. BILLING FACTORS

### A. Billing Demand

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 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), BPA shall instead bill the purchaser in accordance with the provisions of section V.C of the GRSPs.

**B. Billing Energy**

The billing energy under the Special Industrial rate shall be the Measured Energy for the billing month, minus any kilowatt-hours on which BPA assesses the charge for unauthorized increase.

## SECTION IV. 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 Special Industrial Power rate.

**B. Unauthorized Increase Charge**

**1. Rate for Unauthorized Increase**

a. 100.00 mills per kilowatt-hour during billing months August through March.

b. 57.40 mills per kilowatt-hour during billing months April through July.

**2. Application of the Charge**

During any billing month, BPA may assess the unauthorized increase charge on the number of kilowatt-hours 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.

**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 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. 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. 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 SI-95 rate is not based on the cost of resources.

**B.** The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

**C.** The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

## Schedule CE-95
# Emergency Capacity Rate

## SECTION I. AVAILABILITY

This schedule is available for the purchase of capacity provided the purchaser requests such capacity and BPA has determined that capacity is available for such purpose. This schedule is available when:

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

B. the purchaser wishes to displace higher-cost firm capacity resources which are otherwise available to meet the purchaser's load.

This schedule supersedes Schedule CE-93 which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

## SECTION II. RATE

### A. Demand Charge

As mutually agreed by BPA and the purchaser, up to $0.321 per kilowatt of demand per calendar day or portion thereof.

### B. Intertie Charge

The demand charge specified above shall be increased by $0.044 per kilowatt per day 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 day. If BPA is unable to meet subsequent requests by a purchaser for delivery at the demand previously established during such day, the billing demand for that day 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-95 rate is 85.8 percent Exchange and 14.2 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 19.6 mills per kilowatt-hour.

C. The forecasted cost of resources to meet load growth is 55.7 mills per kilowatt-hour.

## Schedule NR-95
# 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-93, which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions (GRSPs).

## SECTION II. RATE

### A. Demand Charge

1. $5.357 per kilowatt of billing demand occurring during all Peak Period hours during a billing month.

2. No demand charge during Offpeak Period hours.

### B. Energy Charge

1. 28.66 mills per kilowatt-hour of billing energy for the billing months September through March.

2. 25.10 mills per kilowatt-hour 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; 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) 55 percent of the Measured Energy; and

(2) 45 percent of the Computed Energy Maximum.

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

(1) 43 percent of the Measured Energy; and

(2) 57 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 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. Irrigation Discount

BPA shall apply an irrigation discount, equal to 4.90 mills per kilowatt-hour, to the charges for qualifying energy purchased under this rate schedule. 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.

### C. Conservation Surcharge

The Conservation Surcharge shall be applied in accordance with section III.C.6 of the GRSPs and subsequent to any other rate adjustments.

### D. 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**

a. 100.00 mills per kilowatt-hour during billing months August through March.

b. 57.40 mills per kilowatt-hour during billing months April through July.

**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:

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

(b) 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:

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

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

**E. 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.5 of the GRSPs. Computed requirements purchasers are not subject to the Coincidental Billing Adjustment for scheduled power.

**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 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.

**G. 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 billing demand and estimated computed average energy requirement for the billing month shall be subject to the following surcharge for each additional kilowatt-hour so returned:

1. 4.25 mills per kilowatt-hour for the months of April through October; and

2. 1.80 mills per kilowatt-hour 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-95 rate is 89.7 percent Exchange and 10.3 percent New Resources.

**B.** The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

**C.** The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

## Schedule NF-95
## 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-95 supersedes Schedule NF-93, which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's GRSPs.

### SECTION II. RATES

The average cost of nonfirm energy is 23.31 mills per kilowatt-hour. The NF-95 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 27.97 mills per kilowatt-hour.

**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 2.00 mills per kilowatt-hour, where the Incremental Cost is defined as all identifiable costs (expressed in mills per kilowatt-hour) 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 12.91 mills per kilowatt-hour of billing energy.

## SECTION III. ADJUSTMENTS TO RATES

### A. Guaranteed Delivery Surcharge

A surcharge of 2.00 mills per kilowatt-hour of billing energy is applied to guaranteed delivery of nonfirm energy under the Standard rate and Market Expansion rate.

### B. Intertie Charge

The Intertie Charge, on rate offers under any of the rates specified above, for sales of nonfirm energy scheduled for delivery over the Pacific Northwest-Pacific Southwest Intertie shall be:

1. inapplicable for rate offers of less than 23.31 mills per kilowatt-hour;

2. at the discretion of BPA, from zero through 3.23 mills per kilowatt-hour, for rate offers of 23.31 mills per kilowatt-hour; or

3. 3.23 mills per kilowatt-hour, for rate offers greater than 23.31 mills per kilowatt-hour.

## 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. Eligibility Criteria for Market Expansion rate**

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 kilowatt-hour.

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 kilowatt-hour.

b. When more than one Market Expansion rate is 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 2.00 mills per kilowatt-hour. The rate applicable to a purchaser shall be the highest Market Expansion rate offered that is below the purchaser's qualifying decremental cost minus 2.00 mills per kilowatt-hour.

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 4.00 mills per kilowatt-hour. 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 kilowatt-hour.

**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 2.00 mills per kilowatt-hour.

**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 (WSPP)**

BPA may make available nonfirm energy for transactions under the 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 not exceed the maximum rate specified in the WSPP Agreement. The rate for WSPP sales 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 92.7 percent FBS and 7.3 percent New Resources.

B. The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

C. The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

## Schedule SS-95
## 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-95 supersedes Schedule SS-93, which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions (GRSPs).

### 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 1.00 mill per kilowatt-hour.

### SECTION III. BILLING FACTOR

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. General Requirements

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, and

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. BPA Service Priority**

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-95 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 19.80 mills per kilowatt-hour.

**C.** The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

## Schedule PS-95
# Power Shortage Rate Schedule

## SECTION I. AVAILABILITY

This schedule is available inside the Pacific Northwest for the purchase of Shortage Power to a utility when a shortage exists on its system and the utility requests Shortage Power under this rate schedule, or when Shortage Power is being delivered to a utility as the result of statewide or regionwide curtailment. This schedule is also available for sales under the Share-the-Shortage agreement, or a similar substitute agreement.

This rate schedule is also available inside the Pacific Northwest when BPA arranges for purchase energy at the request of a customer.

BPA is not obligated to make Shortage Power available or broker power under this rate schedule unless specified by contract. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions.

## SECTION II. RATES

### A. Power Rate

The power rate is any offered rate not to exceed 100.00 mills per kilowatt-hour. The offered rate may be specified as an energy charge only or as demand and energy charges.

### B. Brokering Rate

The brokering rate may be up to 1.00 mill per kilowatt-hour for services provided when BPA arranges for energy purchases for a customer from a seller other than BPA.

## SECTION III. BILLING FACTORS

The billing factors shall be:

### A. Power Purchases

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

#### 1. Billing Demand

The billing demand shall be the Contract Demand as specified in the contract initiating such arrangement or as mutually agreed to by the parties. Otherwise the billing demand shall be the Measured Demand as adjusted for power factor.

**2. Billing Energy**

The billing energy shall be the Contract Energy as specified in the contract initiating such arrangement or as mutually agreed to by the parties. Otherwise the billing energy shall be the Measured Energy.

**B. Brokering Services**

When BPA arranges for energy purchases at the request of a customer, the purchaser shall be billed for such services based on the total amount of kilowatt-hours purchased.

## SECTION IV. ADJUSTMENTS AND SPECIAL PROVISIONS

**A. Power Factor Adjustment**

The adjustment for power factor for BPA customers that are billed for shortage power on metered amounts, when specified in this rate schedule or in the contracts, 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 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.

**B. Power Brokering**

The charge for power brokering only applies to the service provided by BPA of finding purchased power for a customer from a seller other than BPA. BPA may agree to provide other services in addition to finding purchased power, but these services shall be billed separately at charges specified in the appropriate rate schedule(s) or agreement(s). Such services may include, but are not limited to, wheeling and load shaping.

**C. Share-the-Shortage Transactions**

In the event a Share-the-Shortage type agreement is executed, BPA may make shortage power available to participants under such agreement. Any transactions entered into by BPA pursuant to the Share-the-Shortage agreement shall be subject to the terms and conditions specified in that agreement. The PS-95 rate does not incorporate the agreement but the agreement controls if there is any conflict between the PS-95 rate and the agreement. The rate for transactions under the Share-the-Shortage agreement is any rate within the limits specified by the power rate but may not exceed the maximum rate specified in the agreement. The rate for Share-the-Shortage transactions is independent of any rate offered under this rate schedule for sales that do not fall

under the agreement. The PS-95 power rate shall not be available for transactions with a party who triggers the Share-the-Shortage agreement if BPA elects to meet its required service obligations under the agreement by entering into an alternative agreement.

## SECTION V. RESOURCE COST CONTRIBUTION

BPA has made the following determinations:

**A.** The approximate cost contribution of different resource categories to the PS-95 rate is based upon the BPA's highest cost resource which currently is an FBS resource.

**B.** The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

**C.** The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

## Schedule RP-95
## 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; or

**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-93, which went into effect on October 1, 1993. Sales under this schedule are made subject to BPA's General Rate Schedule Provisions (GRSPs).

### SECTION II. RATE

**A. Demand Charge**

1. $3.640 per kilowatt of billing demand occurring during all Peak Period hours during a billing month.

2. No demand charge during Offpeak Period hours.

**B. Energy Charge**

25.30 mills per kilowatt-hour 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 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-95 rate is not based on the cost of resources.

**B.** The forecasted average cost of resources available to BPA under average water conditions is 19.80 mills per kilowatt-hour.

**C.** The forecasted cost of resources to meet load growth is 60.64 mills per kilowatt-hour.

# General Rate Schedule Provisions

## Table of Contents


Page

**I. Adoption of Revised Rate Schedules and General Rate Schedule Provisions** ..... A-44
- A. Approval of Rates ..... A-44
- B. General Provisions ..... A-44

**II. Types of BPA Service** ..... A-44
- A. Priority Firm Power ..... A-44
- B. New Resource Firm Power ..... A-45
- C. Industrial Firm Power ..... A-45
- D. Special Industrial Power ..... A-46
- E. Auxiliary Power ..... A-46
- F. Shortage Power ..... A-46
- G. Surplus Firm Power ..... A-46
- H. Nonfirm Energy ..... A-46
- I. Reserve Power ..... A-47

**III. Billing Factors and Billing Adjustments** ..... A-47

A. Billing Factors for Demand ..... A-47
- 1. Measured Demand ..... A-47
- 2. Ratchet Demand ..... A-48
- 3. Contract Demand ..... A-49
- 4. Computed Peak Requirement ..... A-49
- 5. Computed Average Energy Requirement ..... A-49
- 6. Operating Demand ..... A-50
- 7. Curtailed Demand ..... A-50
- 8. Restricted Demand ..... A-50
- 9. Auxiliary Demand ..... A-50
- 10. BPA Operating Level ..... A-51

B. Billing Factors for Energy ..... A-52
1. Measured Energy ..... A-52
2. Computed Energy Maximum ..... A-53
3. Contract Energy ..... A-53
C. Billing Adjustments ..... A-53
1. Power Factor Adjustment ..... A-53
2. Outage Credit ..... A-54
3. Low Density Discount ..... A-54
4. Irrigation Discount ..... A-56
5. Coincidental Billing ..... A-58
6. Conservation Surcharge ..... A-59
D. Billing-Related Definitions ..... A-59
1. Peak Period ..... A-59
2. Offpeak Period ..... A-59

**IV. Other Definitions** ..... A-59
A. Computed Requirements Purchasers ..... A-59
1. Designation as a Computed Requirements Purchaser ..... A-59
2. Purpose of the Computed Requirements Designation ..... A-60
B. Definitions Relating to Nonfirm Energy Decremental Cost ..... A-60
C. NF Rate Cap ..... A-60
1. Application of the NF Rate Cap ..... A-60
2. Monthly Notification of the NF Rate Cap ..... A-60
3. NF Rate Cap Formula ..... A-61
4. Determination of BASC ..... A-61
5. Determination of Decremental Fuel Cost ..... A-62
6. California Gas Price ..... A-62
7. California Petroleum Price ..... A-63
8. Weighting Factors ..... A-64
D. Determination of BPA's Average System Cost ..... A-66

**V. Application of Rates Under Special Circumstances** ..... A-66
A. Energy Supplied for Emergency Use ..... A-66
B. Construction, Test and Start-up, and Station Service ..... A-66
C. Application of Rates During Initial Operation Period-Transitional Service ..... A-67
1. Eligibility for Transitional Service ..... A-67

2. Calculation of the Daily Demand ..... A-67
3. Billing for Transitional Service ..... A-67
D. Changes in a DSI's BPA Operating Level ..... A-68
E. Restriction of Deliveries ..... A-68

**VI. Billing Information** ..... A-68
A. Determination of Estimated Billing Data ..... A-68
B. Load Shift and Outage Reports ..... A-69
C. Billing for New Large Single Loads ..... A-69
D. Determination of Measured Demand ..... A-69
E. Determination of Measured Energy ..... A-70
F. Billing Month ..... A-70
G. Payment of Bills ..... A-70
1. Computation of Bills ..... A-70
2. Estimated Bills ..... A-70
3. Due Date ..... A-71
4. Late Payment ..... A-71
5. Disputed Billings ..... A-71
6. Revised Bills ..... A-71

**VII. Variable Industrial Rate Parameters and Adjustments** ..... A-72
A. Monthly Average Aluminum Price Determination ..... A-72
1. Calculation of the Monthly Billing Aluminum Price ..... A-72
2. Notification of the Monthly Average Aluminum Price ..... A-72
3. Changes in Aluminum Price Indicators ..... A-72
B. Annual Adjustments to the Lower and Upper Pivot Aluminum Prices ..... A-73
1. Implementation Procedures ..... A-73
2. Annual Adjustment Procedures ..... A-73
3. Cost Escalators ..... A-74
4. Average Historical Aluminum Price ..... A-76
5. Average Historical Lower Pivot Aluminum Price ..... A-76
6. Price Deflator Procedures ..... A-77

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

### A. Approval of Rates

These 1995 rate schedules and General Rate Schedule Provisions (GRSPs) shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (FERC). BPA will request FERC approval effective October 1, 1995. BPA proposes that the following schedules, and the GRSPs associated with these schedules, be effective for 1 year: PF-95, IP-95, VI-95, SI-95, CE-95, NR-95, SS-95, NF-95, PS-95, and RP-95.

### B. General Provisions

These 1995 rate schedules, and the GRSPs associated with these rate schedules, supersede BPA's 1993 rate schedules (which became effective October 1, 1993) to the extent stated in the Availability section of each 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 for direct consumption, construction, test and startup, 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 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. New Resource Firm Power**

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 (IOUs) pursuant to power sales contracts with BPA, and

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

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. Industrial Firm Power**

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. Special Industrial Power**

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. Shortage Power**

Shortage Power is energy or energy with capacity, provided by BPA to a purchaser to serve such purchaser's regional load under circumstances where the purchaser is in danger of curtailing firm load even though the purchaser is operating all available resources and exercising all contractual rights to firm power to the maximum level feasible. In the event of a state ordered or regionwide load curtailment, a power deficiency is deemed to exist for those purchasers whose power supply condition is in part causally related to the state(s) initiated load curtailment.

**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-95. Nonfirm energy also may be supplied under the Share-the-Savings rate schedule, SS-95, 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; or

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 kilowatt-hours 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-95) shall be made at the rate determined pursuant to section III of the VI-95

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 kilowatt-hour 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 kilowatt-hours 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 kilowatt-hours 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 kilowatt-hours 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:

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

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 kilowatt-hours 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. LDDs 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. Eligibility Criteria

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 Calendar Year (CY) 1995, the average Priority Firm Power rate shall be the average of the PF-93 Preference rate for 9 months and the PF-95 Preference rate for 3 months;

(4) the purchaser's kilowatt-hour-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 kilowatt-hour-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 kilowatt-hour-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 kilowatt-hour-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 4.90 mills per kilowatt-hour 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 LDD, 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. However, if the purchaser also purchases energy from BPA for general requirements, and receives an irrigation discount on those purchases, a second irrigation discount will not be applied to that energy through the RPSA exchange. Therefore, the irrigation discount will not be applied to any portion of the purchaser's irrigation sales qualifying for the RPSA exchange that receives the discount as a general requirements purchase.

(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 regional 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 regional 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 regional 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 kilowatt-hours) by month;

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

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

(5) total energy purchased from BPA under the Priority Firm or New Resource rate by month in kilowatt-hours; 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. 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 Special Provisions Exhibits of the Power Sales Contract, GCP E 17.

### 6. 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 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.

# 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 kilowatt-hour) 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 kilowatt-hour) 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 a 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 BPA's Average System Cost (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 29.41 mills per kilowatt-hour.

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

**4. Determination of BASC**

For purposes of determining 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 WGU and WOU developed in sections IV.C.8.a and b, respectively, rounded to the nearest tenth of a mill.

**6. California Gas Price**

The 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 MGPs 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 MGPs were reported and rounded to the nearest one-tenth of a cent; and

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 kilowatt-hour.

**7. California Petroleum Price**

The 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 EPM published by the 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; and

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 kilowatt-hour.

**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 EPM published by the 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; and

(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 EPM published by the 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; and

(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 or 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 BASC, the following definitions 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-95, and Emergency Capacity rate schedule, CE-95, 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 actual firm 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 scheduled meter-reading dates. The billing month will not exceed 31 days in any case. While it may be necessary to read meters on a day other than the scheduled meter-reading date, for determination of billing demand, the billing month will cease at 2400 hours on the last scheduled meter-reading date. Schedules will be predetermined. The customer must give 30 days notice to request a change to the schedule.

## 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 Financial Services 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 financial services group.

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. If the amount of the revised bill is less than or equal to the amount of the original bill, the revised bill shall replace all previous bills issued by BPA that pertain to the specified customer for the specified billing period and the revised bill shall have the same date as the replaced bill.

b. If a revision causes an additional amount to be due BPA or the specified customer beyond the amount of the original bill, a revised bill will be issued for the difference 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, 1991, 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 1991 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 determination 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, 1991, 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. 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:

(1) (2)*(AAP) - ALP:

where

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

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

(2) 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

(3) 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. Cost Escalators**

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) Electricity Cost Index

The average VI rate in mills per kilowatt-hour 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 kilowatt-hour (the average VI-86 rate assuming the plateau energy charge and the Discount for Quality of First Quartile Service in 1986).

(2) Labor Cost Index

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 0.944 (the value of the GNP Implicit Price Deflator for 1985 with 1987 = 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 VI rate has been in effect beginning August 1986. 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 VI rate has been in effect beginning August 1986, 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 B

# TRANSMISSION RATE SCHEDULES AND GENERAL TRANSMISSION RATE SCHEDULE PROVISIONS

# TRANSMISSION RATE SCHEDULES

## TABLE OF CONTENTS


| | | Page |
|---|---|---|
| FPT-95 | Formula Power Transmission Rate | B-1 |
| FPT(3)-95 | Formula Power Transmission Rate (3-year rate adjustment period) | B-4 |
| IR-95 | Integration of Resources Rate | B-7 |
| NT-95 | Network Integration Transmission Rate | B-10 |
| PT-95 | Point-to-Point Firm Transmission Rate | B-15 |
| ET-95 | Energy Transmission Rate | B-18 |
| IS-95 | Southern Intertie Transmission Rate | B-20 |
| IN-95 | Northern Intertie Transmission Rate | B-22 |
| IE-95 | Eastern Intertie Transmission Rate | B-24 |
| MT-95 | Market Transmission Rate | B-25 |
| UFT-95 | Use-of-Facilities Transmission Rate | B-27 |
| AF-95 | Advance Funding Rate | B-29 |
| TGT-95 | Townsend-Garrison Transmission Rate | B-31 |
| AC-95 | Southern Intertie Annual Costs Rate and Billing Provisions | B-34 |

## SCHEDULE FPT-95
# FORMULA POWER TRANSMISSION RATE

## SECTION I. AVAILABILITY

This schedule supersedes schedule FPT-93.1 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 Federal Columbia River Transmission System. 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 Rate Schedule Provisions.

## SECTION II. RATE

The monthly charge shall be A or B.

### A. Embedded Cost

### 1. Full-Year Service

The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the Agreement.

#### a. Main Grid Charge

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

(1) Main Grid Distance Factor: The amount computed by multiplying the Main Grid Distance by $0.0439 per mile

(2) Main Grid Interconnection Terminal Factor: $0.30

(3) Main Grid Terminal Factor: $0.49

(4) Main Grid Miscellaneous Facilities Factor: $2.33

**b. Secondary System Charge**

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

(1) Secondary System Distance Factor: The amount determined by multiplying the Secondary System Distance by $0.3145 per mile

(2) Secondary System Transformation Factor: $4.48

(3) Secondary System Intermediate Terminal Factor: $1.42

(4) Secondary System Interconnection Terminal Factor: $0.98

**2. Partial-Year Service**

The monthly charge per kilowatt of billing demand shall be as specified in Section II.A.1 for all months of the year except for agreements with terms 5 years or less and which specify service for fewer than 12 months per year. The monthly charge shall be:

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

**b.** During other months, the monthly charge defined in Section II.A.1 multiplied by 0.2.

**B. Opportunity Cost**

For applications for new service or increases in current service, Opportunity Costs may be charged if those costs are higher than the rates in section II.A. Opportunity Cost is the net loss of revenue or the net increase in generation cost caused by displacing one transaction with another when the transmission system is so constrained that both transactions cannot be handled at the same time. Loss of revenue resulting from competition shall not be included in the determination of the Opportunity Cost. The Opportunity Cost shall not be higher than the incremental cost of any new facilities or upgrades necessary to alleviate the capacity constraint except: 1) when the transaction term is for one year or less, or 2) for that portion of the transaction term during which BPA is diligently pursuing efforts to design and construct incremental facilities identified in the Agreement that are necessary to alleviate the capacity constraint.

## SECTION III. BILLING FACTORS

### A. Embedded Cost

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

1. The Transmission Demand;

2. The highest hourly Scheduled Demand for the month; or

3. The Ratchet Demand.

### B. Opportunity Cost

Billing factors shall be specified in the Agreement.

## SECTION IV. OTHER PROVISIONS

### A. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section W. of the Adjustments, Charges, and Special Rate Provisions.

### B. Reservation Charge for Transmission Capacity

Customers who request new or increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service are subject to the Reservation Charge for Transmission Capacity specified in section X. of the Adjustments, Charges, and Special Rate Provisions.

### C. Rates Applicable to FPT Service

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

## SCHEDULE FPT(3)-95
## FORMULA POWER TRANSMISSION RATE

### SECTION I. AVAILABILITY

This schedule supersedes schedule FPT-91.3 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 Federal Columbia River Transmission System. 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 Rate Schedule Provisions.

### SECTION II. RATE

The monthly charge shall be A or B.

**A. Embedded Cost**

#### 1. Full-Year Service

The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the Agreement.

**a. Main Grid Charge**

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

(1) Main Grid Distance Factor: The amount computed by multiplying the Main Grid Distance by $0.0439 per mile

(2) Main Grid Interconnection Terminal Factor: $0.30

(3) Main Grid Terminal Factor: $0.49

(4) Main Grid Miscellaneous Facilities Factor: $2.33

**b. Secondary System Charge**

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

(1) Secondary System Distance Factor: The amount determined by multiplying the Secondary System Distance by $0.3145 per mile

(2) Secondary System Transformation Factor: $4.48

(3) Secondary System Intermediate Terminal Factor: $1.42

(4) Secondary System Interconnection Terminal Factor: $0.98

## 2. Partial-Year Service

The monthly charge per kilowatt of billing demand shall be as specified in Section II.A.1 for all months of the year except for agreements with terms 5 years or less and which specify service for fewer than 12 months per year. The monthly charge shall be:

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

**b.** During other months, the monthly charge defined in Section II.A.1 multiplied by 0.2.

## B. Opportunity Cost

For applications for new service or increases in current service, Opportunity Costs may be charged if those costs are higher than the rates in section II.A. Opportunity Cost is the net loss of revenue or the net increase in generation cost caused by displacing one transaction with another when the transmission system is so constrained that both transactions cannot be handled at the same time. Loss of revenue resulting from competition shall not be included in the determination of the Opportunity Cost. The Opportunity Cost shall not be higher than the incremental cost of any new facilities or upgrades necessary to alleviate the capacity constraint except: 1) when the transaction term is for one year or less, or 2) for that portion of the transaction term during which BPA is diligently pursuing efforts to design and construct incremental facilities identified in the Agreement that are necessary to alleviate the capacity constraint.

## SECTION III. BILLING FACTORS

### A. Embedded Cost

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

1. The Transmission Demand;

2. The highest hourly Scheduled Demand for the month; or

3. The Ratchet Demand.

### B. Opportunity Cost

Billing factors shall be specified in the Agreement.

## SECTION IV. OTHER PROVISIONS

### A. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section W. of the Adjustments, Charges, and Special Rate Provisions.

### B. Reservation Charge for Transmission Capacity

Customers who request new or increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service are subject to the Reservation Charge for Transmission Capacity specified in section X. of the Adjustments, Charges, and Special Rate Provisions.

### C. Rates Applicable to FPT Service

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

## SCHEDULE IR-95
## INTEGRATION OF RESOURCES RATE

### SECTION I. AVAILABILITY

This schedule supersedes IR-93 and is available for firm transmission service for electric power and energy using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. 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 Rate Schedule Provisions.

### SECTION II. RATE

The monthly charge shall be A or B.

**A. Embedded Cost**

The monthly charge shall be the sum of 1 and 2.

**1. Demand Charge**

**a.** $0.503 per kilowatt of billing demand; or

**b.** For Points of Integration (POI) specified in the Agreement as being short distance POIs, 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)] * $0.503 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 serving load of the customer. Short distance POIs are determined by BPA after considering factors in addition to transmission distance.

**2. Energy Charge**

1.22 mills per kilowatthour of billing energy.

**B. Opportunity Cost**

For applications for new service or increases in current service, Opportunity Costs may be charged if those costs are higher than the rates in section II.A. Opportunity Cost is the net loss of revenue or the net increase in generation cost caused by displacing one transaction with another when the transmission system is so constrained that both transactions cannot be handled at the same time. Loss of revenue resulting from competition shall not be included in the determination of the Opportunity Cost. The Opportunity Cost shall not be higher than the incremental cost of any new facilities or upgrades necessary to alleviate the capacity constraint except: 1) when the transaction term is for one year or less, or 2) for that portion of the transaction term during which BPA is diligently pursuing efforts to design and construct incremental facilities identified in the Agreement that are necessary to alleviate the capacity constraint.

## 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 ET-95 rate, 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. Embedded Cost**

**1. Billing Demand**

The billing demand shall be the largest of:

**a.** The Transmission Demand, or, if defined in the Agreement, the Total Transmission Demand;

**b.** The highest hourly Scheduled Demand for the month; or

**c.** The Ratchet Demand.

**2. Billing Energy**

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

**B. Opportunity Cost**

Billing factors shall be specified in the Agreement.

## SECTION IV. OTHER PROVISIONS

### A. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section W. of the Adjustments, Charges, and Special Rate Provisions.

### B. Reservation Charge for Transmission Capacity

Customers who request new or increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service are subject to the Reservation Charge for Transmission Capacity specified in section X. of the Adjustments, Charges, and Special Rate Provisions.

### C. Rates Applicable to IR Service

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

## SCHEDULE NT-95
# NETWORK INTEGRATION TRANSMISSION RATE

## SECTION I. AVAILABILITY

This schedule is available to each customer that executes a Network Integration Transmission Agreement (Agreement) for delivery of power to the customer's Network Load over the Federal Columbia River Transmission System, excluding the Southern Intertie, the Northern Intertie, the Eastern Intertie, and Generation Integration segments (Network Transmission System). Terms and conditions of Network Integration Transmission service are specified in a tariff. Capitalized terms used in this rate schedule have the same definitions that are set forth in the tariff. This schedule is available also for transmission service of a similar nature ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is not available to customers taking service under the Integration of Resources or Formula Power Transmission rates. Service under this schedule is subject to BPA's General Rate Schedule Provisions.

## SECTION II. RATE

The monthly charge shall be the sum of A and B.

### A. Demand Charge

(Seasonal Load Ratio Share * BPA's Seasonal Cost Component)

+ (Annual Load Ratio Share * (BPA's Annual Cost Component + Customer Facilities Credit))

- Customer Facilities Credit

where

"BPA's Seasonal Cost Component" is $8,150,000, which equals 50 percent of Integrated Network cost, excluding Integrated Network costs to be recovered from non-Federal uses and BPA's extraregional power sales.

"BPA's Annual Cost Component" is $19,295,000, which equals 50 percent of Integrated Network cost plus Fringe and Delivery segment costs, excluding all such segment costs to be recovered from non-Federal uses and BPA's extraregional power sales.

"Customer Facilities Credit" is the annual cost of customer-owned transmission facilities which would be included in BPA's revenue requirement for the Integrated Network, Fringe, and Delivery segments if BPA owned such customer facilities. The specification of which customer-owned transmission facilities shall be included in the "Customer Facilities Credit" shall be based on a determination of whether BPA would be responsible for providing such facilities, in accordance with BPA's Customer Service Policy, if the requesting party were a BPA full requirements power customer. The annual cost of the identified customer-owned transmission facilities shall be based on the customer's costs. The "Customer Facilities Credit" would be specified as a monthly amount in an exhibit to the Agreement.

**B. Redispatch Charge/Credit**

The Redispatch Charge/Credit shall be the Opportunity Cost resulting from the conditions set forth in 1 through 3, below. The Opportunity Cost is the net loss of revenue or the net increase in generation cost caused by displacing one transaction with another when the transmission system is so constrained that both transactions cannot be handled at the same time. Loss of revenue resulting from competition shall not be included in the determination of the Opportunity Cost. The Opportunity Cost shall not be higher than the incremental cost of any new facilities or upgrades necessary to alleviate the capacity constraint except: 1) when the transaction term is for one year or less, or 2) for that portion of the transaction term during which BPA is diligently pursuing efforts to design and construct incremental facilities identified in the Agreement that are necessary to alleviate the capacity constraint.

1. New Member System
   To the extent that a) a Network Integration customer gives notice of its intent to add a new Member System and sufficient capacity is not available on the FCRTS to provide the requested service without impairing reliability to BPA's Native Load Customers and other firm uses of the FCRTS, and b) the requested service can be provided in whole or in part by redispatching the system, the Customer shall pay to BPA the Opportunity Costs caused by the redispatch.

2. Transmission Capacity Constraints
   When BPA implements procedures pursuant to the Network Operating Agreement to redispatch BPA's and/or a Network Integration customer's resources to maintain the reliability of the Network Transmission System and avoid curtailment of service, the total opportunity cost impact of such procedures shall be shared among BPA and its Network Integration customers. The redispatch charge for transmission capacity constraints is:

   Load Ratio Share * Total Redispatch Cost

3. Customer Redispatch Obligation
When a Network Integration customer redispatches its resources, at BPA's request, to create additional firm capacity on the Network Transmission System to allow BPA to provide new firm transmission service, such customer shall receive a credit each month for any Opportunity Costs that the customer incurs.

## SECTION III. DETERMINATION OF LOAD RATIO SHARE

Each month, for each customer that executes an Agreement, BPA shall compute the Annual Load Ratio Share and Seasonal Load Ratio Share:

A. Annual Load Ratio Share = $\frac{\text{Customer's Annual CP Load}}{\text{BPA's Total Annual Load}}$

B. Seasonal Load Ratio Share = $\frac{\text{Customer's Seasonal CP Load}}{\text{BPA's Total Seasonal Load}}$

where

"BPA's Total Annual Load" equals the average of the monthly peak loads on the FCRTS for the preceding 12 months. The monthly peak load consists of BPA's Native Load and the "Customer's CP Load," and excludes BPA wheeling loads and extraregional power sales. The determination of "BPA's Total Annual Load" shall be consistent with the determination of "BPA's Annual Cost" and "BPA's Seasonal Cost" used in the calculation of the Demand Charge (section II.A.).

"BPA's Total Seasonal Load" equals the average of the monthly peak loads on the FCRTS for the preceding December, January, and February. The monthly peak load consists of BPA's native load and the "Customer's CP Load," and excludes BPA wheeling loads and extraregional power sales. The determination of "BPA's Total Seasonal Load" shall be consistent with the determination of "BPA's Annual Cost" and "BPA's Seasonal Cost" used in the calculation of the Demand Charge (section II.A.).

"Customer's Annual CP Load" is the average of the customer's Network Load at the time of the monthly peak as determined for "BPA's Total Annual Load" for the preceding 12 months, less the billing demands of any service provided to the customer by BPA under requirements or long-term power sales contracts. If load data for customer coincident peaks for 12 months is not available, the customer's non-coincident peak load for the preceding 12 months will be used in determining its Network Load.

"Customer's Seasonal CP Load" is the average of the customer's Network Load at the time of the monthly peak as determined for "BPA's Total Seasonal" for the preceding December, January, and February, less the billing demands of any service provided to the customer by BPA under requirements or long-term power sales contracts during those

months. If load data for customer coincident peaks for the 3 months is not available, the customer's non-coincident peak load for these months will be used in determining its Network Load.

"Network Load" is a customer's total load (excluding any wheeling load) within the Pacific Northwest region as defined in section 3(14)(A) and (B) of the Northwest Power Act (16 U.S.C. § 839a(14(A) and (B)).

## SECTION IV. OTHER PROVISIONS

### A. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section W. of the Adjustments, Charges, and Special Rate Provisions.

### B. Reservation Charge for Transmission Capacity

Customers who request new or increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service are subject to the Reservation Charge for Transmission Capacity specified in section X. of the Adjustments, Charges, and Special Rate Provisions.

### C. Direct Assignment Facilities

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Network Integration Transmission customer under an applicable rate schedule.

### D. Rates Applicable to NT Service

The rates specified in section II are applicable to service over available transmission capacity. NT customers that integrate new Network Resources, new Member systems, or new Native Load Customers that would require BPA to construct new facilities or upgrades shall be subject to incremental cost rates for such service. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

**E. Rate Adjustment Due to FERC Order Under FPA §212**

If, after review by FERC, this rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. §824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to this rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective, however, only prospectively from the date of the final FERC order granting final approval of this rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under this rate schedule prior to the effective date of such prospective modification.

## SCHEDULE PT-95
# POINT-TO-POINT FIRM TRANSMISSION RATE

## SECTION I. AVAILABILITY

This schedule is available to each Customer that executes a Point-to-Point Firm Transmission Agreement (Agreement) for firm transmission service of a minimum duration of one month and for nonfirm transmission in amounts not to exceed the customer's total Transmission Demand over the Integrated Network of the Federal Columbia River Transmission System (FCRTS). Terms and conditions of Point-to-Point Firm Transmission service are specified in a tariff. This schedule is available also for transmission service of a similar nature ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is not available to customers taking service under the Integration of Resources or Formula Power Transmission rates. Service under this schedule is subject to BPA's General Rate Schedule Provisions.

## SECTION II. RATE

The charge shall be A or B.

### A. Embedded Cost

$1.005 per kilowatt per month of billing demand.

### B. Opportunity Cost

For applications for new service or increases in current service, Opportunity Costs may be charged if those costs are higher than the rates in section II.A. Opportunity Cost is the net loss of revenue or the net increase in generation cost caused by displacing one transaction with another when the transmission system is so constrained that both transactions cannot be handled at the same time. Loss of revenue resulting from competition shall not be included in the determination of the Opportunity Cost. The Opportunity Cost shall not be higher than the incremental cost of any new facilities or upgrades necessary to alleviate the capacity constraint except: 1) when the transaction term is for one year or less, or 2) for that portion of the transaction term during which BPA is diligently pursuing efforts to design and construct incremental facilities identified in the Agreement that are necessary to alleviate the capacity constraint.

## SECTION III. BILLING FACTORS

### A. Embedded Cost

The billing demand for the rate specified in II.A shall be the Transmission Demand as specified in the Agreement.

**B. Opportunity Cost**

The billing factor(s) for the rate in section II.B shall be specified in the Agreement.

## SECTION IV. OTHER PROVISIONS

**A. Reactive Power Charge**

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section W. of the Adjustments, Charges, and Special Rate Provisions.

**B. Reservation Charge for Transmission Capacity**

Customers who request new or increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service are subject to the Reservation Charge for Transmission Capacity specified in section X. of the Adjustments, Charges, and Special Rate Provisions.

**C. Direct Assignment Facilities**

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Point-to-Point Firm Transmission customer under an applicable rate schedule.

**D. Rates Applicable to PT Service**

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

**E. Rate Adjustment Due to FERC Order Under FPA § 212**

If, after review by FERC, this rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. § 824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to this rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective, however, only prospectively from the date of the final FERC order granting final approval of this rate schedule for FERC-ordered transmission

service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under this rate schedule prior to the effective date of such prospective modification.

## SCHEDULE ET-95
# ENERGY TRANSMISSION RATE

## SECTION I. AVAILABILITY

This schedule supersedes ET-93 and is available for transmission service between points within the Pacific Northwest using Federal Columbia River Transmission System (FCRTS) facilities other than the Southern Intertie, Eastern Intertie, or the Northern Intertie. This rate is available for firm transmission of less than 1 month duration and for nonfirm transmission. Terms and conditions of Energy Transmission service are specified in a tariff. This schedule is available for transmission service of a similar nature ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§824j and 824k). Service under this schedule is subject to BPA's General Rate Schedule Provisions.

## SECTION II. RATE

The charge shall be A or B.

### A. Embedded Cost

2.33 mills per kilowatthour.

### B. Opportunity Cost

For applications for new service or increases in current service, Opportunity Costs may be charged if those costs are higher than the rates in section II.A. Opportunity Cost is the net loss of revenue or the net increase in generation cost caused by displacing one transaction with another when the transmission system is so constrained that both transactions cannot be handled at the same time. Loss of revenue resulting from competition shall not be included in the determination of the Opportunity Cost. Loss of revenue resulting from competition shall not be included in the determination of the Opportunity Cost rate.

## SECTION III. BILLING FACTORS

The billing energy for the rate specified in section II.A. shall be the greater of the monthly sum of scheduled kilowatthours, or the amount of energy specified in the Agreement.

The billing factor for the rate in section II.B. shall be specified in the Agreement.

## SECTION IV. OTHER PROVISIONS

### A. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section W. of the Adjustments, Charges, and Special Rate Provisions.

### B. Rate Adjustment Due to FERC Order Under FPA § 212

If, after review by FERC, this rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. §824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to this rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective, however, only prospectively from the date of the final FERC order granting final approval of this rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under this rate schedule prior to the effective date of such prospective modification.

## SCHEDULE IS-95
## SOUTHERN INTERTIE TRANSMISSION RATE

## SECTION I. AVAILABILITY

This schedule supersedes IS-93 and is available for all transmission on the Southern Intertie. Service under this schedule is subject to BPA's General Rate Schedule Provisions.

## SECTION II. RATE

The rates below apply to both north-to-south and south-to-north transactions.

**A. Nonfirm Transmission Rate**

3.89 mills per kilowatthour of billing energy.

**B. Firm Transmission Rate**

The charge shall be 1 or 2.

**1. Embedded Cost**

$0.828 per kilowatt per month of billing demand, and

2.00 mills per kilowatthour of billing energy.

**2. Opportunity Cost**

For applications for new firm service or increases in current firm service, Opportunity Costs may be charged if those costs are higher than the rates in section II.B.1. Opportunity Cost is the net loss of revenue or the net increase in generation cost caused by displacing one transaction with another when the transmission system is so constrained that both transactions cannot be handled at the same time. Loss of revenue resulting from competition shall not be included in the determination of the Opportunity Cost. The Opportunity Cost shall not be higher than the incremental cost of any new facilities or upgrades necessary to alleviate the capacity constraint except: 1) when the transaction term is for one year or less, or 2) for that portion of the transaction term during which BPA is diligently pursuing efforts to design and construct incremental facilities identified in the Agreement that are necessary to alleviate the capacity constraint.

## SECTION III. BILLING FACTORS

### A. Nonfirm Transmission

For nonfirm service 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 pro rata 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. Firm Transmission

For firm transmission service under Section II.B.1, 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.

For firm transmission service under Section II.B.2, the billing factors shall be specified in the Agreement.

## SECTION IV. OTHER PROVISIONS

### A. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section W. of the Adjustments, Charges, and Special Rate Provisions.

### B. Reservation Charge for Transmission Capacity

Customers who request new or increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service will be subject to the Reservation Charge for Transmission Capacity specified in section X. of the Adjustments, Charges, and Special Rate Provisions.

### C. Rates Applicable to IS Service

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

## SCHEDULE IN-95
## NORTHERN INTERTIE TRANSMISSION RATE

### SECTION I. AVAILABILITY

This schedule supersedes IN-93 and is available for all transmission on the Northern Intertie pursuant to an Agreement. Service under this schedule is subject to BPA's General Rate Schedule Provisions.

### SECTION II. RATE

The rates below apply to both north-to-south and south-to-north transactions.

**A. Nonfirm Transmission Rate**

0.66 mills per kilowatthour of billing energy.

**B. Firm Transmission Rate**

The charge shall be 1 or 2.

**1. Embedded Cost**

$0.121 per kilowatt per month of billing demand, and

0.33 mills per kilowatthour of billing energy.

**2. Opportunity Cost**

For applications for new firm service or increases in current firm service, Opportunity Costs may be charged if those costs are higher than the rates in section II.B.1. Opportunity Cost is the net loss of revenue or the net increase in generation cost caused by displacing one transaction with another when the transmission system is so constrained that both transactions cannot be handled at the same time. Loss of revenue resulting from competition shall not be included in the determination of the Opportunity Cost. The Opportunity Cost shall not be higher than the incremental cost of any new facilities or upgrades necessary to alleviate the capacity constraint except: 1) when the transaction term is for one year or less, or 2) for that portion of the transaction term during which BPA is diligently pursuing efforts to design and construct incremental facilities identified in the Agreement that are necessary to alleviate the capacity constraint.

## SECTION III. BILLING FACTORS

Billing demand shall be specified in the Agreement.

Billing energy shall be the monthly sum of the scheduled kilowatthours, unless otherwise specified in the Agreement.

## SECTION IV. OTHER PROVISIONS

### A. Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section W. of the Adjustments, Charges, and Special Rate Provisions.

### B. Reservation Charge for Transmission Capacity

Customers who request new or increased firm transmission service under this rate and want to reserve transmission capacity to accommodate such service are subject to the Reservation Charge for Transmission Capacity specified in section X. of the Adjustments, Charges, and Special Rate Provisions.

### C. Rates Applicable to IN Service

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

## SCHEDULE IE-95
# EASTERN INTERTIE TRANSMISSION RATE

## SECTION I. AVAILABILITY

This schedule supersedes IE-93 and is available for all nonfirm transmission on the Eastern Intertie. Service under this schedule is subject to BPA's General Rate Schedule Provisions.

## SECTION II. RATE

2.05 mills per kilowatthour.

## SECTION III. BILLING FACTORS

The billing energy shall be the monthly sum of the scheduled kilowatthours, unless otherwise specified in the Agreement.

## SECTION IV. OTHER PROVISIONS

**Reactive Power Charge**

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section W. of the Adjustments, Charges, and Special Rate Provisions.

## SCHEDULE MT-95
## MARKET TRANSMISSION RATE

### SECTION I. AVAILABILITY

This schedule supersedes MT-91 and is available for transmission service for transactions using Federal Columbia River Transmission System facilities pursuant to the Western Systems Power Pool (WSPP) Agreement. Service under this schedule is subject to BPA's General Rate Schedule Provisions.

### SECTION II. RATE

The charge shall be determined in advance by BPA. The charge shall be based on the duration of the proposed transaction and shall not exceed the following rates.

**A. Hourly Rate**

The maximum charge shall be 6.5 mills per kilowatthour where the total hourly revenues from a given transaction during a calendar day shall not exceed the product of the Daily rate and the maximum demand scheduled during such day.

**B. Daily Rate**

The maximum charge shall be $.105 per kilowattday where the total demand charge revenues in any consecutive 7-day period shall not exceed the product of the Weekly rate and the highest demand experienced on any day in the 7-day period.

**C. Weekly Rate**

The maximum charge shall be $.52 per kilowattweek.

**D. Monthly Rate**

The maximum charge shall be $2.27 per kilowattmonth.

### SECTION III. BILLING FACTORS

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

## SECTION IV. OTHER PROVISIONS

### Reactive Power Charge

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section V. of the Adjustments, Charges, and Special Rate Provisions.

## SCHEDULE UFT-95
# USE-OF-FACILITIES TRANSMISSION RATE

## SECTION I. AVAILABILITY

This schedule supersedes UFT-83 unless otherwise provided in the Agreement, and is available for firm transmission over specified Federal Columbia River Transmission System (FCRTS) facilities. Service under this schedule is subject to BPA's General Rate Schedule Provisions.

## 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:

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 Federal Columbia River Power System 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 AF-95
## ADVANCE FUNDING RATE

### SECTION I. AVAILABILITY

This schedule is available to customers who execute an Agreement that provides for BPA to collect capital and related costs through advance funding of specified BPA-owned Federal Columbia River Transmission System (FCRTS) facilities used for:

**A.** Interconnection or integration of resources with the FCRTS;

**B.** Upgrades or reinforcements of the FCRTS for transmission service; or

**C.** Other transmission service arrangements, as determined by BPA.

Service under this schedule is subject to BPA's General Rate Schedule Provisions.

### SECTION II. RATE

The charge is the sum of the actual capital and related costs as specified in the Agreement. Such actual capital and related costs include, but are not limited to, costs of design, materials, construction, overhead, spare parts, and all incidental costs necessary to provide service as defined in the Agreement.

### SECTION III. PAYMENT

**A. Advance Payment**

Payment to BPA shall be specified in the Agreement as either:

1. A lump sum advance payment; or

2. Advance payments pursuant to a schedule of progress payments.

Such advance payment or payments shall be based on an estimate of capital and related costs as specified in the Agreement.

**B. Adjustment to Advance Payment**

BPA shall determine the actual capital and related costs of the specified FCRTS facilities as soon as practicable after the date of commercial operation, as determined by BPA. The customer will either receive a refund from BPA or be billed for additional payment for the difference between the advance payment and the actual capital and related costs. The adjustment, whether a refund or payment, will reflect interest, calculated from the date of commercial operation to the date of the refund or payment. BPA shall compute interest using the weighted average interest rate on BPA's outstanding bonds.

## SCHEDULE TGT-95
## TOWNSEND-GARRISON TRANSMISSION RATE

### SECTION I. AVAILABILITY

This schedule supersedes TGT-1 and 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. Service under this schedule is subject to BPA's General Rate Schedule Provisions.

### 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 1 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:**

Intertie Charge =

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

**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 BPA'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 Nonfirm 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.

## SCHEDULE AC-95
## SOUTHERN INTERTIE ANNUAL COSTS RATE

**SECTION I. AVAILABILITY**

This schedule is applicable to each party (Capacity Owner) that executes a PNW AC Intertie Capacity Ownership Agreement (Agreement). Billings pursuant to this schedule are subject to the Billing Provisions in Exhibit B of the Agreement. This rate schedule shall be effective on the first day of the fiscal year following the earlier of interim or final FERC approval of this rate schedule. Unless otherwise defined in this rate schedule, capitalized terms used in this rate schedule shall have the respective definitions set forth in section 1 of this Agreement.

**SECTION II. RATE**

**A. Operations**

The monthly charge equals:

$$\frac{\text{Operations Cost} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Operations Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Operations Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any Allocated Direct Costs for Bonneville's PNW AC Intertie, operations Indirect Costs for Bonneville's PNW AC Intertie, and operations Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section I of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Operations rate shall be calculated using the forecast Operations Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Operations Cost shall be calculated using the forecast Operations Cost less the Operations Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

**B. Maintenance**

The monthly charge equals:

$$\text{Maintenance Cost} * \frac{\text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Maintenance Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Maintenance Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any maintenance Direct Costs for Bonneville's PNW AC Intertie, maintenance Indirect Costs for Bonneville's PNW AC Intertie, and maintenance Overhead Costs for Bonneville's PNW AC Intertie for such fiscal year, each being determined in accordance with section II of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Maintenance rate shall be calculated using the forecast Maintenance Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Maintenance Cost shall be calculated using the forecast Maintenance Cost less the Maintenance Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

**C. General Plant**

The monthly charge equals:

$$\text{General Plant Cost} * \frac{\text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to General Plant Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"General Plant Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year any costs (including direct costs, indirect costs, overhead costs, and AFUDC) for Bonneville's general plant investment for such fiscal year. The method for determining General Plant Cost is set forth in section IV of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the General Plant rate shall be calculated using the General Plant Cost in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for General Plant Cost shall be calculated using the General Plant Cost less the General Plant Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

**D. Other Costs**

The monthly charge equals:

$$\text{Other Costs} * \text{Capacity Ownership Percentage}$$
$$\text{Months}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Other Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Other Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's other costs for Bonneville's PNW AC Intertie described in and determined pursuant to section V of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the Other Costs rate shall be calculated using the forecast Other Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Other Costs shall be calculated using the forecast Other Costs less the Other Costs already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

**E. Contracts and Rates**

The monthly charge equals:

$$\text{Contracts and Rates Costs} * \frac{\text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Contracts and Rates Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Contracts and Rates Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any fiscal year Bonneville's total contracts and rates costs (as described in section VI of Exhibit I) for such fiscal year as functionalized and allocated in accordance with section VI of Exhibit I to determine Contracts and Rates Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Contracts and Rates Cost is determined in accordance with section VI of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Contracts and Rates Cost determined in accordance with section VI of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Contracts and Rates rate shall be calculated using the forecast Contracts and Rates Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Contracts and Rates Cost shall be calculated using the forecast Contracts and Rates Cost less the Contracts and Rates Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

**F. Power Scheduling**

The monthly charge equals:

$$\text{Power Scheduling Costs} * \frac{\text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to Power Scheduling Cost, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"Power Scheduling Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's total power scheduling costs (as described in section VII of Exhibit I) as functionalized and allocated in accordance with section VII of Exhibit I to determine Power Scheduling Costs for Bonneville's PNW AC Intertie.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

Power Scheduling Cost is determined in accordance with section VII of Exhibit I as of the Effective Date. If Exhibit I is amended pursuant to subsection 19(k) of the Agreement to provide that the Power Scheduling Cost determined in accordance with section VII of Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains) is directly assigned to the Capacity Owners pursuant to such amended Exhibit I (and reflected in the Operating Plan for the fiscal year to which such Operating Plan pertains), the Capacity Ownership Percentage in the monthly charge calculation for such fiscal year shall be replaced by the ratio of (a) each Capacity Ownership Share to (b) the sum of all Capacity Ownership Shares.

The monthly charge for the Power Scheduling rate shall be calculated using the forecast Power Scheduling Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for Power Scheduling Cost shall be calculated using the forecast Power Scheduling Cost less the Power Scheduling Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

**G. End of Term**

The monthly charge equals:

$$\frac{\text{End of Term Costs} * \text{Capacity Ownership Percentage}}{\text{Months}}$$

Where

"Months" is equal to 12, or, if the Operating Plan has, during the fiscal year to which such Operating Plan pertains, been amended with respect to End of Term Costs, the number of full months remaining in the fiscal year after such amended Operating Plan becomes effective for which Capacity Owners have not been billed.

"End of Term Costs" means, upon and after the effective date of Exhibit B pursuant to this Agreement, Bonneville's costs associated with decommissioning the PNW AC Intertie determined in accordance with section VIII of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The monthly charge for the End of Term rate shall be calculated using the forecast End of Term Costs in the Operating Plan in effect during the month for which the monthly charge is calculated; provided, however, if the Operating Plan is amended during the fiscal year to which such Operating Plan pertains, the monthly charge for End of Term Costs shall be calculated using the forecast End of Term Costs less the End of Term Cost already billed for such fiscal year for the remaining months of the fiscal year following such amendment.

**H. Replacements and Reinforcements**

1. For each Replacement, the charge equals:

   Replacement Cost * Capacity Ownership Percentage

2. For each Reinforcement, the charge equals:

   Reinforcement Cost * Capacity Ownership Percentage

Where

"Replacement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Replacement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Replacement, all capitalized to plant-in-service together with (1) simple

interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Replacement Cost does not include capitalized general plant cost. The method for determining Replacement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Reinforcement Cost" means, upon and after the effective date of Exhibit B pursuant to this Agreement, for any Reinforcement, the Direct Costs, Indirect Costs, Overhead Costs, and AFUDC for such Reinforcement, all capitalized to plant-in-service together with (1) simple interest on the foregoing costs accrued from the date on which Bonneville stops accruing AFUDC on the foregoing costs until the due date of the bill to Capacity Owner for the foregoing costs pursuant to subparagraph 9(b)(2)(B) and (2) the costs of removal and any salvage credit associated with removal or replacement of existing facilities. Reinforcement Cost does not include capitalized general plant cost. The method for determining Reinforcement Costs for Bonneville's PNW AC Intertie is set forth in section III of Exhibit I.

"Capacity Ownership Percentage" is as defined in subsection 1(k) of each Capacity Owner's Agreement.

The charge for the Replacements and Reinforcements rate shall use the actual Replacement Cost and Reinforcement Cost in the Operating Plan.

## SECTION III. ADJUSTMENTS

If an amendment to the Operating Plan results in a net amount that Bonneville owes the Capacity Owners pursuant to sections II.A-G or pursuant to section II.H, Bonneville shall refund such net amount pursuant to paragraph 9(f)(4) of the Agreement.

The monthly charges assessed Capacity Owners under sections II.A-G shall be adjusted, and payment or refund made with interest, pursuant to paragraphs 9(b)(2) or 9(f)(4) of the Agreement, to reflect amendments to the Operating Plan that occur after the year to which such Operating Plan pertains. A Capacity Owner's share of the adjustment shall be determined using the same Capacity Ownership Percentage used in the billings under sections II.A-G during the fiscal year that such Operating Plan is effective.

# ANNUAL COSTS RATE
# BILLING PROVISIONS

## I. GENERAL PROVISIONS

### A. Approval of Rates

The annual costs rate shall become effective upon interim approval or upon final confirmation and approval by FERC. Bonneville will request FERC approval of such rate schedule effective on the first day of a Bonneville fiscal year.

### B. Application of Billing Provisions

These Billing Provisions shall apply to bills rendered by Bonneville pursuant to the annual costs rate.

### C. Definition of Terms

The meaning of terms used in the annual costs rate shall be as defined in the Agreement or, if no definition is provided by the Agreement, such terms shall be defined according to applicable Federal law.

## II. BILLING INFORMATION

### Payment of Bills

Charges pursuant to the annual costs rate shall be included in Bonneville's monthly power bill to Capacity Owner. Failure to receive a power bill shall not release Capacity Owner from liability for payment. Power bills for amounts due of $50,000 or more must be paid by direct wire transfer. If Capacity Owner anticipates special difficulties in meeting this requirement, Capacity Owner may request and Bonneville may approve an exemption from this requirement. Power bills for amounts due Bonneville 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 Bonneville. The procedures to be followed in making direct wire transfers will be provided by Bonneville's Financial Services Group and updated as necessary.

#### (1) Computation of Bills

(a) Bonneville shall bill Capacity Owner in accordance with the annual costs rate.

(b) Capacity Owner shall provide necessary information to Bonneville for any computation required to determine proper charges pursuant to the Agreement and shall cooperate with Bonneville in the exchange of additional information which may be reasonably useful for respective operations.

(c) Bills rendered pursuant to this Agreement shall be rounded to whole dollar amounts, by eliminating any amount which is less than 50 cents and increasing any amounts from 50 cents to 99 cents to the next higher whole dollar.

**(2) Billing Month**

For charges pursuant to the annual costs rate the billing month shall be the same as for the power bill rendered by Bonneville to Capacity Owner.

**(3) Due Date**

Charges pursuant to the annual costs rate shall be included in the power bill rendered by Bonneville to Capacity Owner and shall be due as part of the power bill when such power bill is due.

**(4) Late Payment**

The penalties for failure to pay a bill in full on or before close of business on the due date shall be the same as those contained in the late payment provisions in Bonneville's General Rate Schedule Provisions in effect on the date of the bill; provided, however, that no other provision of any such General Rate Schedule Provisions, including, but not limited to, provisions regarding cancellation, termination, or suspension of service, shall have application with respect to the payment of any rate or charge pursuant to the annual costs rate set forth in Exhibit B. Bonneville's right to suspend service for late payment under the Agreement shall be pursuant to paragraph 9(e)(1) of this Agreement, which right shall in no way be limited by this section.

**(5) Disputed Bills**

In the event of a disputed bill, full payment shall be rendered to Bonneville and the disputed amount noted. Disputed amounts are subject to the late payment provisions specified in section II(4) of the Billing Provisions of this Exhibit B. Bonneville shall separately account for the disputed amount. If it is determined that Capacity Owner is entitled to the disputed amount, Bonneville shall refund the disputed amount with interest, such interest to be determined by Bonneville's Financial Services Group. In the event that Bonneville and Capacity Owner do not resolve such dispute, Capacity Owner shall not be prevented by this section II(5)

of the Billing Provisions of this Exhibit B from initiating arbitration pursuant to and to the extent allowed by section 15 of this Agreement.

**(6) Revised Bills**

If Bonneville determines that it has over- or under-charged Capacity Owner due to a computational error or because of an amendment to the Operating Plan in any given billing month, Bonneville may render to Capacity Owner a revised bill.

(i) If the amount of the revised bill is less than or equal to the amount of the original bill for such billing month, the revised bill shall replace the original bill issued by Bonneville. The revised bill shall have the same date as the original bill.

(ii) If the amount of the revised bill is greater than the amount of the original bill for such billing month, a new bill will be issued for the difference between the revised bill and the original bill. The date of the new bill shall be its date of issuance, and Capacity Owner shall make payment to Bonneville as specified in the Billing Provisions of this Exhibit B.

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