B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2010 BPA Rate Case
Wholesale Power Rate Initial Proposal

# WHOLESALE POWER RATE DEVELOPMENT STUDY

February 2009

WP-10-E-BPA-05

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**2010 WHOLESALE POWER RATE DEVELOPMENT STUDY**

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TABLES

## COMMONLY USED ACRONYMS

| | |
|---|---|
| AC | alternating current |
| AFUDC | Allowance for Funds Used During Construction |
| AGC | Automatic Generation Control |
| ALF | Agency Load Forecast (computer model) |
| aMW | average megawatt |
| AMNR | Accumulated Modified Net Revenues |
| ANR | Accumulated Net Revenues |
| AOP | Assured Operating Plan |
| ASC | Average System Cost |
| ATC | Accrual to Cash |
| BAA | Balancing Authority Area |
| BASC | BPA Average System Cost |
| Bcf | billion cubic feet |
| BiOp | Biological Opinion |
| BPA | Bonneville Power Administration |
| Btu | British thermal unit |
| CAISO | California Independent System Operator |
| CBFWA | Columbia Basin Fish & Wildlife Authority |
| CCCT | combined-cycle combustion turbine |
| cfs | cubic feet per second |
| CGS | Columbia Generating Station |
| CHJ | Chief Joseph |
| C/M | consumers per mile of line for LDD |
| COB | California-Oregon Border |
| COE | U.S. Army Corps of Engineers |
| COI | California-Oregon Intertie |
| COSA | Cost of Service Analysis |
| COU | consumer-owned utility |
| Council | Northwest Power and Conservation Council |
| CP | Coincidental Peak |
| CRAC | Cost Recovery Adjustment Clause |
| CRC | Conservation Rate Credit |
| CRFM | Columbia River Fish Mitigation |
| CRITFC | Columbia River Inter-Tribal Fish Commission |
| CSP | Customer System Peak |
| CT | combustion turbine |
| CY | calendar year (January through December) |
| DC | direct current |
| DDC | Dividend Distribution Clause |
| dec | decremental |
| DJ | Dow Jones |
| DO | Debt Optimization |
| DOE | Department of Energy |

| | |
|---|---|
| DOP | Debt Optimization Program |
| DSI | direct-service industrial customer or direct-service industry |
| EAF | energy allocation factor |
| ECC | Energy Content Curve |
| EIA | Energy Information Administration |
| EIS | Environmental Impact Statement |
| EN | Energy Northwest, Inc. (formerly Washington Public Power Supply System) |
| EPA | Environmental Protection Agency |
| EPP | Environmentally Preferred Power |
| EQR | Electric Quarterly Report |
| ESA | Endangered Species Act |
| F&O | financial and operating reports |
| FBS | Federal Base System |
| FCRPS | Federal Columbia River Power System |
| FCRTS | Federal Columbia River Transmission System |
| FERC | Federal Energy Regulatory Commission |
| FELCC | firm energy load carrying capability |
| FPA | Federal Power Act |
| FPS | Firm Power Products and Services (rate) |
| FY | fiscal year (October through September) |
| GAAP | Generally Accepted Accounting Principles |
| GARD | Generation and Reserves Dispatch (computer model) |
| GCL | Grand Coulee |
| GCPs | General Contract Provisions |
| GEP | Green Energy Premium |
| GI | Generation Integration |
| GRI | Gas Research Institute |
| GRSPs | General Rate Schedule Provisions |
| GSP | Generation System Peak |
| GSU | generator step-up transformers |
| GTA | General Transfer Agreement |
| GWh | gigawatthour |
| HLH | heavy load hour |
| HOSS | Hourly Operating and Scheduling Simulator (computer model) |
| HYDSIM | Hydro Simulation (computer model) |
| IDC | interest during construction |
| inc | incremental |
| IOU | investor-owned utility |
| IP | Industrial Firm Power (rate) |
| IPR | Integrated Program Review |
| IRP | Integrated Resource Plan |
| ISD | incremental standard deviation |
| ISO | Independent System Operator |
| JDA | John Day |
| kaf | thousand (kilo) acre-feet |

| | |
|---|---|
| kcfs | thousand (kilo) cubic feet per second |
| K/I | kilowatthour per investment ratio for LDD |
| ksfd | thousand (kilo) second foot day |
| kV | kilovolt (1000 volts) |
| kVA | kilo volt-ampere (1000 volt-amperes) |
| kW | kilowatt (1000 watts) |
| kWh | kilowatthour |
| LDD | Low Density Discount |
| LGIP | Large Generator Interconnection Procedures |
| LLH | light load hour |
| LME | London Metal Exchange |
| LOLP | loss of load probability |
| LRA | Load Reduction Agreement |
| m/kWh | mills per kilowatthour |
| MAE | mean absolute error |
| Maf | million acre-feet |
| MCA | Marginal Cost Analysis |
| MCN | McNary |
| Mid-C | Mid-Columbia |
| MIP | Minimum Irrigation Pool |
| MMBtu | million British thermal units |
| MNR | Modified Net Revenues |
| MOA | Memorandum of Agreement |
| MOP | Minimum Operating Pool |
| MORC | Minimum Operating Reliability Criteria |
| MOU | Memorandum of Understanding |
| MRNR | Minimum Required Net Revenue |
| MVAr | megavolt ampere reactive |
| MW | megawatt (1 million watts) |
| MWh | megawatthour |
| NCD | non-coincidental demand |
| NEPA | National Environmental Policy Act |
| NERC | North American Electric Reliability Corporation |
| NFB | National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) |
| NIFC | Northwest Infrastructure Financing Corporation |
| NLSL | New Large Single Load |
| NOAA Fisheries | National Oceanographic and Atmospheric Administration Fisheries (formerly National Marine Fisheries Service) |
| NOB | Nevada-Oregon Border |
| NORM | Non-Operating Risk Model (computer model) |
| Northwest Power Act | Pacific Northwest Electric Power Planning and Conservation Act |
| NPCC | Northwest Power and Conservation Council |
| NPV | net present value |
| NR | New Resource Firm Power (rate) |

| | |
|---|---|
| NT | Network Transmission |
| NTSA | Non-Treaty Storage Agreement |
| NUG | non-utility generation |
| NWPP | Northwest Power Pool |
| OATT | Open Access Transmission Tariff |
| O&M | operation and maintenance |
| OMB | Office of Management and Budget |
| OTC | Operating Transfer Capability |
| OY | operating year (August through July) |
| PDP | proportional draft points |
| PF | Priority Firm Power (rate) |
| PI | Plant Information |
| PMA | (Federal) Power Marketing Agency |
| PNCA | Pacific Northwest Coordination Agreement |
| PNRR | Planned Net Revenues for Risk |
| PNW | Pacific Northwest |
| POD | Point of Delivery |
| POI | Point of Integration or Point of Interconnection |
| POM | Point of Metering |
| POR | Point of Receipt |
| Project Act | Bonneville Project Act |
| PS | BPA Power Services |
| PSC | power sales contract |
| PSW | Pacific Southwest |
| PTP | Point to Point Transmission (rate) |
| PUD | public or people's utility district |
| RAM | Rate Analysis Model (computer model) |
| RAS | Remedial Action Scheme |
| Reclamation | U.S. Bureau of Reclamation |
| RD | Regional Dialogue |
| REC | Renewable Energy Certificate |
| REP | Residential Exchange Program |
| RevSim | Revenue Simulation Model (component of RiskMod) |
| RFA | Revenue Forecast Application (database) |
| RFP | Request for Proposal |
| RiskMod | Risk Analysis Model (computer model) |
| RiskSim | Risk Simulation Model (component of RiskMod) |
| RMS | Remote Metering System |
| RMSE | root-mean squared error |
| ROD | Record of Decision |
| RPSA | Residential Purchase and Sale Agreement |
| RTF | Regional Technical Forum |
| RTO | Regional Transmission Operator |
| SCADA | Supervisory Control and Data Acquisition |
| SCCT | single-cycle combustion turbine |
| Slice | Slice of the System (product) |

| | |
|---|---|
| SME | subject matter expert |
| TAC | Targeted Adjustment Charge |
| TDA | The Dalles |
| Tcf | trillion cubic feet |
| TPP | Treasury Payment Probability |
| Transmission System Act | Federal Columbia River Transmission System Act |
| TRL | Total Retail Load |
| TRM | Tiered Rate Methodology |
| TS | BPA Transmission Services |
| UAI | Unauthorized Increase |
| UDC | utility distribution company |
| URC | Upper Rule Curve |
| USFWS | U.S. Fish and Wildlife Service |
| VOR | Value of Reserves |
| WECC | Western Electricity Coordinating Council (formerly WSCC) |
| WIT | Wind Integration Team |
| WPRDS | Wholesale Power Rate Development Study |
| WREGIS | Western Renewable Energy Generation Information System |
| WSPP | Western Systems Power Pool |

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# 1. INTRODUCTION

## 1.1 Purpose of the Wholesale Power Rate Development Study

The Wholesale Power Rate Development Study (WPRDS) serves two primary purposes: (1) to demonstrate the methodology and processes used to develop the proposed power rates that will be applied to BPA's wholesale power products and services; and (2) to demonstrate how the proposed power rates will recover all of BPA's power costs for the applicable rate period.

## 1.2 Rate Process Overview

The development of rates in the WPRDS uses inputs from a variety of sources. Loads and resources are provided to the WPRDS by the Loads and Resources Study, WP-10-E-BPA-01, and its accompanying documentation, WP-10-E-BPA-01A. The Market Price Forecast Study, WP-10-E-BPA-03, and its accompanying documentation, WP-10-E-BPA-03A, provide the WPRDS with information regarding electricity market prices used in the WPRDS for seasonal and diurnal differentiation of energy rates, as well as for informing the development of demand rates. Revenue requirement information is provided by the Revenue Requirement Study, WP-10-E-BPA-02, and its accompanying documentation, WP-10-E-BPA-02A and WP-10-E-BPA-02B. The Risk Analysis and Mitigation Study, WP-10-E-BPA-04, and its accompanying documentation, WP-10-E-BPA-04A and WP-10-E-BPA-04B, provide short-term balancing purchases expenses, augmentation expenses, secondary energy sales and revenue, and Planned Net Revenues for Risk (PNRR). The Section 7(b)(2) Rate Test Study, WP-10-E-BPA-06, with its documentation, WP-10-E-BPA-06, provide the WPRDS the results of the section 7(b)(2) rate test. Past versions of the WPRDS have included the explanation and documentation for generation inputs and other inter-business line cost allocations. These issues are now addressed in a separate Generation Inputs Study, WP-10-E-BPA-08. The results of the Generation Inputs Study are provided to the WPRDS as revenue credits. The results of the rate development process, including rates for power products and services, plus general rate schedule provisions, appear in WP-10-E-BPA-07. The revenues resulting from the rates developed herein are used by the Revenue Requirement Study in the Revised Revenue Test. Revenue Requirement Study, WP-10-E-BPA-02, section 4.3.

## 1.3 Organization of the WPRDS

The WPRDS is divided into six sections. The first is this Introduction. Section 2 describes the criteria and methods applied in the development of power rate design, including Slice, and transmission services such as General Transfer Agreements. Section 3 describes the WPRDS cost of service analysis, rate design adjustments, and Slice product separation step. Section 4 describes the revenue forecasts that are used to test current and proposed rates for sufficiency to recover BPA's revenue requirement. Section 5 describes the Priority Firm Power (PF-10), New Resource Firm Power (NR-10), Industrial Firm Power (IP-10), and Firm Power Products and Services (FPS-10) rate schedules. Section 6 describes the development of Average System Costs (ASC), which occurs in the ASC Review Process separate from the WP-10 rate proceeding.

Details supporting the WPRDS inputs, assumptions, and calculations are included in the Documentation, WP-10-E-BPA-05A. The Documentation includes four appendices: Appendix A describes the 7(c)(2) Industrial Margin Study, and Appendices B, C, and D describe BPA's policy for the development of regional conservation and renewable resources.

## 2. RATE DESIGN

The rate design for the wholesale power rates proposed in the WP-10 Initial Proposal is based on the design of the current FY 2009 rates. Each of the following sections describes the components of the various proposed rates. Section 2.1 discusses the monthly and diurnal differentiation of the PF Preference energy rates; the proposed FY 2010-2011 PF energy rates are proportionally scaled from the FY 2009 rates. Section 2.2 describes the monthly and diurnal differentiation of the IP energy rates. Section 2.3 describes the monthly and diurnal differentiation of the NR energy rates. The IP and NR energy rates both are time differentiated based on the marginal cost of power. Section 2.4 discusses the design of rates for Demand, Factoring Service, and Load Variance. Section 2.5 describes Unauthorized Increase (UAI) Charges and Excess Factoring Charges. Section 2.6 discusses the design of the FPS rate. Section 2.7 discusses the Flexible PF and NR Rate Option. Section 2.8 discusses the PF Exchange rate, including the 7(b)(3) Supplemental Rate Charge. Section 2.9 describes the Irrigation Rate Mitigation Product. Section 2.10 describes the Low Density Discount. Section 2.11 discusses the Conservation and Renewables Program. Section 2.12 discusses the Green Energy Premium. Section 2.13 discusses the Targeted Adjustment Charge (TAC). Section 2.14 discusses the GTA Delivery Charge. Section 2.15 discusses the Slice of the System (Slice) product, the Slice revenue requirement, and the Slice rate.

### 2.1 Monthly and Diurnal Differentiation of PF Preference Energy Rates

Monthly and diurnal differentiation of PF Preference energy rates is the same as that used for the current FY 2009 rates, based on the WP-07 Supplemental Final Proposal. Those rates are listed in Table 2.1, below.

**Table 2.1**
**WP-07R PF Preference Energy Rates for FY 2009, $/MWh**

| | A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | OCT | NOV | DEC | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP |
| HLH | $29.21 | $31.15 | $32.51 | $27.60 | $28.19 | $26.15 | $24.54 | $20.50 | $18.55 | $22.85 | $26.76 | $27.62 |
| LLH | $21.40 | $22.72 | $23.85 | $19.96 | $20.16 | $19.17 | $17.64 | $14.17 | $9.85 | $16.73 | $19.85 | $22.17 |

The FY 2010-2011 PF Preference rates are determined by adjusting the rates in Table 2.1 up or down by an equal percentage such that the PF rates will recover the amount of the total revenue requirement for the rate period allocated to the PF Preference rate pool. Documentation, WP-10-E-BPA-05A, Table 2.7.

## 2.2 IP Energy Rates

### 2.2.1 Adjustment to IP Energy Rates for Reserves Provided

BPA has not determined how its direct-service industrial customers (DSIs) will be served and what interruption reserves will be provided by the DSIs. For ratesetting purposes, an assumed sale to the aluminum DSIs of 385 aMW is based on the maximum level of DSI load that could be served at the IP rate at a net cost of of about $59 million. (The net cost is the difference between the cost of acquiring 385 aMW and the revenues from 385 aMW of sales at the IP rate.) This assumed power sale is also assumed to provide interruption reserves to BPA. The interruption reserves are assumed to be similar to those that would be provided under a draft long-term (FY 2012-2028) contract being considered by BPA and DSIs. Although this contract is not intended for use in the FY 2010-2011 rate period, the long-term contract represents preliminary agreement between BPA and DSIs regarding the structure of at least a minimal level of interruption reserves.

The starting point for valuing reserves provided by DSIs is $7.19 per kW per month for capacity, which is the proposed unit cost allocation for Operating Reserves (Supplemental only) in the Generation Inputs Study, WP-10-E-BPA-08, section 5. The Operating Reserves documented in the Generation Inputs Study are provided by the Federal Columbia River Power System (FCRPS), and are available in any hour and on any day.

The reserves provided by DSIs are evaluated using the following criteria. The maximum amount Power Services may pay for incremental within-hour balancing reserve from a DSI is capped at the unit cost for Operating Reserve (Supplemental only) capacity that is provided as a generation input to Transmission Services. The suitability and quality of any reserve provided by the DSIs will be measured by whether such reserves have certain characteristics, some of which are required and others optional.

In addition, any Operating Reserve (Supplemental only) must be consistent with North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) standards and criteria, as follows:

1. The interruptible load must be offline within 10 minutes after a call by BPA.
2. In the event of a system disturbance, the interruptible load must be accessible prior to a request for reserve from other NWPP parties.

In addition to these required characteristics, the issues identified below will be assessed to define when Power Services may pay the maximum unit cost for Operating Reserve (Supplemental only):

1. The extent to which Power Services has the discretion over when and how to use all Operating Reserve and to determine what resources to call on in the event of a system disturbance.
2. Whether there are limitations on the number of times or total minutes the reserve may be utilized.
3. Whether the interruptible load is available to be offline for up to 105 minutes.

The reserves supplied by the FCRPS can be used for the balance of the hour and the entire next hour, and these Operating Reserves meet the WECC and NERC reliability requirements for Operating Reserves that Transmission Services is required to carry. By contrast, the reserves provided under the draft long-term DSI contract can be called upon for a maximum of 60 minutes per event and a maximum of 4 events per month.

The first step in valuing the DSI reserves is to determine the quantity of reserves provided. To do this, BPA reduced the total DSI load to account for wheel-turning load that cannot be curtailed. The wheel-turning load is forecast to be 6 aMW. The reserves provided are 10 percent of the remaining forecast total DSI load based on the draft long-term contract. These reserves are reduced by the availability limitation of 4 hours per month. This reduction reflects the difference in value of supplemental reserves that are available all hours of the month versus these DSI reserves, which are available for only 4 hours per month.

Next, availability as a percentage of available hours is computed by dividing 4 hours by 730 hours in an average month, which equals 0.55 percent. The total available DSI reserve of 38 megawatts is then adjusted by this percent to reflect the actual usable monthly amount of the reserves, which is 0.2077 MW per month. This quantity is converted to total monthly kilowatts for a year by multiplying it first by 1,000 kW per MW and then again by 12 months per year, resulting in usable reserves of 2,496 kW per year. The total value of these DSI reserves is then computed by multiplying the kilowatts of capacity times the $7.19 per kW/month rate, resulting in a total annual value of DSI reserves of $17,946. The value of reserves adjustment to the IP rate is first computed as this total annual value divided by the forecast total aluminum DSI annual energy load of 385 aMW, resulting in a value of $0.01 per MWh.

Summary of DSI Value of Reserves:

| | | |
|---|---|---|
| Embedded Cost | $7.19 | kW/mo |
| Assumed DSI sale | 385 | aMW |
| Assumed Wheel-turning Load | 6 | aMW |
| Interruptible Load | 379 | aMW |
| Percent of DSI sale that is interruptible | 10 | percent |
| MW of interruptible load | 38 | MW |
| Hours per month of interruptible | 4 | |
| Average hours per month | 730 | |
| Percent of month available | 0.55 | percent |
| MW of interruptible load per month | 0.2077 | MW |
| kW of interruptible load per month | 208.0 | kW/mo |
| kW of interruptible load per year | 2,496 | kW/year |
| Total value of Operating Reserves per year | $17,946.00 | per year |
| Value converted to $/MWh on total load | $0.01 | $/MWh |

### 2.2.2 Monthly and Diurnal Differentiation of IP Energy Rates

Monthly and diurnal differentiation of IP energy rates is done based on the rate period average marginal cost of power as determined by the Market Price Forecast Study, WP-10-E-BPA-03. The marginal costs are shown in Table 2.2.

**Table 2.2**
**Marginal Cost of Power, $/MWh**

| | A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | OCT | NOV | DEC | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP |
| HLH | $52.49 | $52.00 | $53.24 | $58.61 | $57.50 | $55.11 | $50.83 | $50.85 | $49.27 | $52.40 | $58.49 | $57.32 |
| LLH | $42.59 | $45.17 | $46.32 | $47.68 | $46.76 | $45.11 | $41.29 | $33.60 | $34.36 | $43.72 | $50.57 | $50.89 |

The FY 2010-2011 IP rates are determined by adjusting the rates in Table 2.2 down by an equal percentage such that IP rates will recover the amount of the total revenue requirement for the rate period allocated to the IP rate pool. Documentation, WP-10-E-BPA-05A, Table 2.10.

### 2.3 Monthly and Diurnal Differentiation of NR Energy Rates

Monthly and diurnal differentiation of NR energy rates is based on the rate period average marginal cost of power as determined by the Market Price Forecast Study, WP-10-E-BPA-03. Those marginal costs are listed in Table 2.2.

The FY 2010-2011 NR rates are determined by adjusting the rates in Table 2.2 down by an equal percentage such that the NR rates will recover the amount of the total revenue requirement for the rate period allocated to the NR rate pool. Documentation, WP-10-E-BPA-05A, Table 2.11.

### 2.4 Demand, Factoring Service, and Load Variance

This section discusses rate design and its relationship to BPA Core Subscription Products.

#### 2.4.1 Core Subscription Products Principles

BPA Core Subscription Products were developed based on the principle that Core Products are billed from a "common table of rates" to ensure equitable comparability of payment among purchasers of different types of Core Products. The common table of rates includes Demand Rates, Heavy Load Hour (HLH) and Light Load Hour (LLH) Energy Rates, and a Load Variance Rate, where applicable. The common table of rates is associated with a table of billing factors that shows the billing determinants appropriate to the specific products. *See* BPA Power Products Catalog, Appendix B, Core Product Billing Factors.

### 2.4.2 Demand Rates for Core Subscription Products

The purpose of the demand rate in the Core Subscription Products is to compensate BPA for three components of firm service: (1) the cost of firming bulk energy, including firm energy provided in flat amounts, as under the Block product; (2) the cost of the service BPA calls "factoring," in which energy is distributed among hours to match a load shape; and (3) the cost of readiness to meet actual load under peak conditions. When combined with energy charges, a demand rate has the effect of increasing the purchaser's average payment per kilowatthour of product, sometimes referred to as the effective rate. If the power delivery is not flat (i.e., peaks during the HLH period), the resulting demand charge plus energy charge makes the effective rate higher than the effective rate of a flat power purchase. To help maintain and ensure equitable comparability, the same demand dollar rate ($/kW per month) will be applied to appropriate demand billing factors for different products such as PF Full Service, Partial Service, and Block products, and for any sales made at the IP and NR rates.

#### 2.4.2.1 Development of Demand Rate

The proposed rate design includes two energy rates for each month, one for HLH and one for LLH. However, the Market Price Forecast Study, WP-10-E-BPA-03, demonstrates there is a different market value for power in each hour. To account for hour-to-hour differentials, a demand rate ($/kW per month) is applied in conjunction with the HLH and LLH energy rates (mills/kWh).

Monthly differentiation of the proposed FY 2010-2011 demand rates is the same as that used for the current FY 2009 rates, based on the WP-07 Supplemental Final Proposal. Those rates are listed in Table 2.3 below.

**Table 2.3**
**WP-07R PF Preference Demand Rates for FY 2009, $/kW**

| | A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | OCT | NOV | DEC | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP |
| Demand | $1.91 | $2.04 | $2.14 | $1.82 | $1.85 | $1.72 | $1.62 | $1.34 | $1.23 | $1.50 | $1.76 | $1.82 |

For the FY 2010-2011 proposed PF preference rates, the demand rates in Table 2.3 are adjusted up or down by the same percentage used for the PF Preference energy rates. The revenues resulting from application of the scaled demand rates are credited to offset the total revenue requirement for the rate period allocated to the PF Preference rate pool. Documentation, WP-10-E-BPA-05A, Table 2.7. The PF demand rates are also used for the IP and NR demand rates.

### 2.4.3 Factoring Service in Core Subscription Products

The term “factoring” is a term of general use in the utility industry. However, for purposes of the Core Subscription Products, the term is specifically defined to mean the BPA service of shaping a given quantity of megawatthours among HLH and LLH periods in each month to follow load. In this context, Factoring Service is an “energy-neutral” service. For example, a customer that has a 67 percent load factor (average monthly energy divided by monthly peak) generally would use more Factoring Service than a customer with a 75 percent load factor. A flat or 100 percent load factor purchase uses no Factoring Service. As a customer’s load factor drops (for example, 57 percent instead of 67 percent), the load shape BPA must serve becomes more extreme, generally requiring more factoring of energy to meet the changes in the load.

The Factoring Service is a part of both the Full Service and the Actual Partial Service products, as explained below. The amount of Factoring Service taken will be checked in the billing process only for those customers with declared dispatchable resources with hourly variability, and customers that purchase the Actual Partial (Complex) product or the Block with Factoring product. Customers without resources, customers whose resources are not dispatchable, and customers whose resources have fixed hourly quantities take and receive exactly the amount of Factoring Service to which they are entitled. Only when customer resources are dispatchable on an hour-to-hour basis is there a possibility of receiving Factoring Service amounts that are less than or greater than the entitlement amount. The BPA Power Product Catalog product descriptions provide further details on the factoring benchmark calculation. Factoring Service that is within the benchmark will result in no excess Factoring Service penalty charges. The entitled amount of Factoring Service will be paid at the PF Preference demand rate applied to the customer's power billing demand.

The Factoring Service is not intended to provide backup or other services for customer resource amounts that are interrupted or otherwise fail to be delivered. If a flat resource fails to be delivered for an hour to a customer within the BPA Balancing Authority Area (BAA), the power product default treatment is to identify that as an unauthorized increase event. By arrangement, other BPA services could apply, such as ancillary services acquired by the customer from Transmission Services or a negotiated backup service.

#### 2.4.3.1 Factoring Service as a Staple-On Product and the Appropriate Billing Demand

The BPA Power Product Catalog states that a customer can purchase the Block Product with Factoring Service as a staple-on product. When Factoring Service is added to the Block Product, it provides within-day and within-month factoring of Block energy. This additional service is priced at the demand rate and applied to the appropriate demand billing factor.

### 2.4.4 The Demand Adjuster

The Demand Adjuster is a billing factor that preserves equitable comparability among customers purchasing different types of Core Products. Full Service Product customers are billed based on their load during the hour of the monthly Generation System Peak (GSP). However, the demand billing factors for the Simple and Complex Actual Partial Service Products and the Block Product with Factoring are based on the customer's system peak load. It is necessary for appropriate product selection and for appropriate customer operation under these products that the demand billing factors for these Partial Service Products be linked to the customer's own system peak. However, using the same dollar rate on different billing demand measures is not directly compatible with the concept of a common table of rates and would create a lack of equitable comparability.

The Demand Adjuster is designed to resolve this problem by adjusting billing demand kilowatts to achieve parity with a customer whose billing demand is measured on the BPA Generation System Peak (GSP). Because a customer's system peak is always equal to or larger than its load on the hour of the GSP, this larger billing factor for these alternative products, if not adjusted, would result in a higher relative demand billing for the Full Service Product. To maintain a level of comparability, given the different demand billing bases for the products, the Demand Adjuster is used to scale down the Billing Demand of the Actual Partial Service Products and the Block Product with Factoring. The Demand Adjuster is a multiplier consisting of a number less than or equal to one. It is calculated by dividing the customer's Total Retail Load (TRL) on the hour of the GSP by the customer's TRL on the hour of the customer's system peak. The minimum Demand Adjuster is 0.6.

**2.4.5 Load Variance Rate**

Another Core Subscription Product, Load Variance, is defined as the variability from forecast of monthly energy consumption within the customer's system. Variability in monthly energy consumption may be caused by weather, economic business cycles, load growth, or load loss. It does not include the variance in load caused by annexation of new load, retail access, or service to New Large Single Loads (NLSL). Such loads will receive Load Variance coverage once the loads are served by BPA under the applicable rate schedule. BPA offers to stand ready to serve the covered variability under the Full Service and Actual Partial Service products. As applied to the Full and Actual Partial Service products, the Load Variance charge allows customers' billing factors to follow actual consumption. This is different than for Block products, where the amounts purchased are fixed in advance.

In establishing the Load Variance rate for FY 2010-2011, the PF-07R Load Variance rate of 0.46 mills/kWh is scaled up or down by the same percentage used for the PF Preference energy rates. The revenues resulting from application of the scaled Load Variance rate are credited to offset the total revenue requirement for the rate period allocated to the PF Preference rate pool.

### 2.5 Unauthorized Increase Charges and Excess Factoring Charges

This Initial Proposal includes separate penalty charges for Unauthorized Increases in Energy usage, Unauthorized Increases in Demand usage, Excess Within-Day Factoring Energy, and Excess Within-Month Factoring Energy. These charges apply to deliveries that exceed contractual entitlements. Minimum penalty charges for Energy, Demand, and Excess Factoring are included, with the potential for relevant price indicies to set effective charges for the month at higher levels than the identified minimums. Collectively, market prices reflected by the Dow Jones Mid-Columbia Indexes (DJ Mid-C Indexes) and the California Independent System Operator (CAISO) price indexes provide a basis for the potential opportunity cost (or actual purchase cost) to BPA of serving energy, demand, or factoring in excess of a customer's contractual entitlement. The inclusion of these market price indices in the penalty charge derivations also ensures an appropriate deterrent against customers placing demand, energy, and factoring burdens on the BPA system during periods of high market prices. Where the index-driven prices exceed the specified minimum charges for a given month, they will constitute the effective charges.

There is the possibility that one or more of the currently identified indexes for determining the penalty charges will cease to exist during the rate period.  The General Rate Schedule Provisions (GRSPs) account for this possibility by allowing a replacement index, either some index already in existence (e.g., the CAISO) or some other relevant future index available at some point during the rate period.  GRSPs, WP-10-E-BPA-07, sections II.H and II.Q.

A reduction in charges is associated with single occurrences that trigger multiple penalties. Specifically, reductions to Excess Within-Month Factoring Charges are possible to the extent that energy in the same diurnal period is assessed the Unauthorized Increase in Energy Charge.

### 2.5.1 Unauthorized Increases in Energy and Demand

If specified in the applicable rate schedule, the charge for Unauthorized Increase in Energy will be applied for any purchaser taking energy in excess of its contractual entitlement.  The rate for a given month will be the highest DJ Mid-C Index price for firm power or the highest CAISO Supplemental Energy price for that month, whichever is greater.  The minimum rate will continue to be set at 100 mills/kWh.

The charge for Unauthorized Increase in Demand will be applied to any purchaser taking demand in excess of its contractual entitlement.  The minimum rate will be set at three times the monthly Demand Rate from the applicable power rate schedule.  The effective rate may be set at a level that exceeds this minimum based on the sum of the hourly CAISO Spinning Reserve Capacity prices during HLH for the month.  The sum of hourly Spinning Reserve Capacity prices during all HLH of the month will be compared to the minimum and, if higher than the minimum, will determine the effective Unauthorized Increase Charge rate for demand.

### 2.5.2 Excess Factoring Charges

The Initial Proposal includes two separate charges for Excess Factoring: (1) the Excess Within-Day Factoring Charge and (2) the Excess Within-Month Factoring Charge. The Within-Day factoring test compares the hour-by-hour shape of the customer's load with the customer's hour-by-hour energy take from BPA within a day. This test identifies whether or not the hour-by-hour shape of the customer's take from BPA has used more within-day factoring service, measured in kilowatthours, than the underlying load would have used. There are separate, but identical, tests for HLH Within-Day Factoring and LLH Within-Day Factoring. For both of these tests, the minimum Excess Factoring Charge rate for each month will be 5 mills/kWh, although it is likely that the charges may be higher, as defined by hourly CAISO Supplemental Energy prices. For HLH, the highest within-day difference during the month between the highest HLH price less the lowest (same day) HLH price, and the 5 mills/kWh minimum, will determine the applicable charge. A corresponding test against the 5 mills/kWh minimum will be applied for the LLH difference to determine the LLH Excess Within-Day Factoring Charge rate.

The sum of the HLH Excess Within-Day Factoring amounts will be billed at the HLH Excess Within-Day Factoring Charge rate. The sum of the LLH Excess Within-Day Factoring amounts will be billed at the LLH Excess Within-Day Factoring Charge rate.

The Within-Month Factoring Test compares the day-by-day shape of the customer's load to the customer's day-to-day energy take from BPA within a month. This test identifies whether the day-by-day shape of the customer's take from BPA used more within-month factoring service than the underlying load would have used. The within-day factoring test (discussed above) is not equipped to identify a factoring service issue if, for example, a customer's resource deliveries were zero for a particular day. The within-month factoring test is equipped to address such an event, however. The within-month factoring test establishes an upper and lower boundary for each diurnal period of the day. Excess Within-Month Factoring for each diurnal period is the greater of: (1) the sum of the megawatthour amounts greater than the upper boundary; or (2) the sum of the megawatthour amounts less than the lower boundary. There will be a separate quantification of Excess Within-Month Factoring for HLH and for LLH. The minimum rate for Excess Within-Month Factoring will be 5 mills/kWh. This minimum will be compared with charges derived from the DJ Mid-C Index prices for firm power and the CAISO Supplemental Energy indexes for the month. For HLH Excess Within-Month Factoring Energy, the effective rate will be the greatest of: (1) 5 mills/kWh; (2) the difference between the highest DJ Mid-C Index price for firm power among all HLH periods for the month and the lowest HLH DJ Mid-C Index price for firm power; and (3) the difference between the highest average hourly CAISO Supplemental Energy price among all HLH periods for the month and the lowest average hourly CAISO Supplemental Energy HLH price. An equivalent test against the 5 mills/kWh minimum rate will be done to determine the effective Excess Within-Month Factoring Charge for LLH.

The Excess Within-Month Factoring energy quantities are reduced by any Unauthorized Increase Energy amounts in the same diurnal period, and only the residual is charged for Excess Within-Month Factoring.

## 2.6 Firm Power Products and Services (FPS-10) Rate

The FPS-10 rate is a market-based or negotiated rate, and it may have a demand component, an energy component, or both. Unbundled products also are available under the FPS-10 rate schedule at flexible rates as mutually agreed by the contracting parties. Applicable transmission rates will apply to the extent required to purchases of firm power under the FPS-10 rate. The West-Wide Price Cap as established or approved by Federal Energy Regulatory Commission (the Commission) will apply to all sales under this rate schedule.

The FPS rate includes a fixed 7(b)(3) Supplemental Rate Charge to recover the section 7(b)(2) rate protection allocated to FPS rates pursuant to section 7(b)(3) of the Northwest Power Act. To retain maximum pricing flexibility, the flexible portion of the FPS rate may be negative, if necessary, so that the total FPS rate will be as negotiated between BPA and the purchaser.

## 2.7 Flexible PF and NR Rate Options

The Flexible PF and NR rate options are offered at BPA's discretion to PF and NR Preference purchasers who purchase under the PF and NR rate schedules and make contractual commitments to purchase under this option. The charges and billing factors under this option are specified by BPA at the time the Administrator offers to make power available to purchasers under this option. The actual charges and billing factors will be mutually agreed by BPA and the purchasers subject to satisfying the following condition: forecast revenues from a purchaser under the Flexible PF and NR rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in the appropriate rate schedule been applied to the same sales.

Notwithstanding the effective dates of the PF-10 and NR-10 rates and associated GRSPs, any rights and obligations of BPA and a customer arising out of the customer's election to participate in the Flexible PF and NR Rate Programs by purchasing under the Flexible PF or NR Rate Option will survive and be fully enforceable until such time as they are fully satisfied.

## 2.8 PF Exchange Rate

The PF Exchange rate applies to the implementation of the Residential Exchange Program (REP). This rate is compared with the exchanging utility's Average System Cost (ASC), and the difference is multiplied by the utility's eligible residential and small farm load (exchange load) to determine monetary REP benefits paid to the utility by BPA. This rate also applies to BPA's actual power sales to exchanging utilities under contractual "in-lieu" transactions. The PF Exchange rate has two components: a common Base PF Exchange rate, and utility-specific

7(b)(3) Supplemental Rate Charges. Neither component of the PF Exchange rate is diurnally differentiated or contains an additional charge for Demand.

### 2.8.1 7(b)(3) Supplemental Rate Charge

If the section 7(b)(2) rate test triggers, the Base PF Exchange rate will be adjusted by a utility-specific 7(b)(3) Supplemental Rate Charge. The Base PF Exchange rate, so adjusted, will be the PF Exchange Rate and will apply to the utility's exchange load in the calculation of its REP benefits. It may be that one or more utilities will apply for the REP after rates have been determined for the rate period. To minimize the risk to BPA and other customers of paying REP benefits that were not contemplated in setting rates, and to give some assurance that PF preference purchasers are receiving section 7(b)(2) rate protection from increased exchange costs, the 7(b)(3) Supplemental Rate Charge applicable to a new REP participant will be the difference between its ASC and the Base PF Exchange rate.

### 2.8.2 Components of the Base PF Exchange Rate

The Base PF Exchange rate begins with the 7(b) rate pool rate, also known as the unbifurcated PF rate, determined prior to the section 7(b)(2) rate test. This is the precursor to the PF rate, and in the absence of a reallocation of costs resulting from the section 7(b)(2) rate test would be the PF Preference rate. Any reallocation of costs due to the section 7(b)(2) rate test and the 7(b)(2) Industrial Adjustment is added to the PF Exchange rate.

The Base PF Exchange rate also contains a transmission cost component. The specific transmission services included in the Base PF Exchange rate are NT base transmission charges, transmission Load Shaping Charges, transmission Scheduling Service and Dispatch, Load Regulation, and Operating Reserves. These transmission services are assumed to be acquired under transmission rate schedules for a load that has a 73 percent load factor. The total transmission cost included in the Base PF Exchange rate is \$4.26/MWh.  The calculation of the \$4.26/MWh is shown below.

$4.26/MWh = (((NT Base Charge + Load Shaping Charge + Scheduling Service and Dispatch) × 12) ÷ (8760 × 0.73)) + Load Regulation + Operating Reserves

Where

| | | |
|---|---|---|
| NT Base Charge | $1,298 | per MW per mo |
| Load Shaping Charge | $367 | per MW per mo |
| Schedule Service and Dispatch | $203 | per MW per mo |
| Monthly Total | $1,868 | per MW per mo |
| Annual Total | $22,416 | per MW per year |
| Load Factor Assumption | 73 | percent |
| Fixed Cost in $/MWh | $3.50 | per MWh |
| Load Regulation | $0.33 | per MWh |
| Operating Reserves | $0.43 | per MWh |
| Total Costs for Transmission | $4.26 | per MWh |

Transmission costs are included in the Base PF Exchange rate to make the rate comparable to a utility's ASC, which includes the utility's allowable transmission expense.

### 2.9 Irrigation Rate Mitigation Product

The Irrigation Rate Mitigation Product (IRMP) is a contract-specific rate and not part of the rate design for this Initial Proposal.  The estimated difference between the forecast revenue at PF rates and at the IRMP rates, $12.036 million per year, is accounted for as an expense in setting rates.  Documentation, WP-10-E-BPA-05A, Table 2.5.5.

## 2.10 Low Density Discount

Section 7(d)(1) of the Northwest Power Act provides that, in order to avoid adverse impacts on retail rates of BPA's purchasers with low system densities, BPA shall apply, to the extent appropriate, discounts to the rate or rates for such purchasers. Such purchasers are utilities with low system densities and with high distribution costs resulting from sparsely populated service areas. The Low Density Discount principles, eligibility criteria, and discount appear in the GRSPs, WP-10-E-BPA-07, Section II.L.

The LDD is determined by two formulas. One formula calculates a qualifying utility's ratio of Total Retail Load (TRL) to its depreciated electric plant, excluding generation plant (the Kilowatthour/Investment or K/I ratio). The other formula calculates the ratio of the number of the utility's consumers to the number of pole miles of distribution lines (the Consumers/Mile or C/M ratio). These ratios are computed with certified data submitted by the purchaser based on the purchaser's entire electric utility system in the Pacific Northwest. For purchasers with service territories that include any area outside the PNW, BPA compiles data submitted by the purchaser separately on the portion of the purchaser's system that is in the PNW. BPA applies the eligibility criteria and discount percentages to the purchaser's system within the PNW, and where applicable, also to its entire system inside and outside the PNW. The purchaser's eligibility for the LDD is determined by the lesser amount of discount applicable to its PNW system or to its combined system inside and outside the PNW. BPA, at its sole discretion, may waive the requirement to submit separate data for a purchaser with a small amount of its system outside the PNW.

The discounts under each ratio range from zero to 5 percent, in increments of one-half percent. The discounts from the two ratios are added together to determine the total discount to purchases under an applicable rate. The LDD for any utility is capped at seven percent.

A change in the discount for any eligible utility will be ramped in from the pre-existing discount. No eligible utility will experience more than a one-half percentage point change (positive or negative) in its LDD beginning October 1, 2006, and each succeeding fiscal year, until the revised LDD percentage is attained. If a utility fails to satisfy the initial eligibility criteria, however, the discount will be zero and will not be ramped in from the existing discount.

The estimated cost of the LDD is $28.3 million for FY 2010 and $28.6 million for FY 2011. See the Documentation, WP-10-E-BPA-05A, Table 4.10, for an example of how the calculation is done for an individual customer.

### 2.11 Conservation and Renewables Program

BPA provides financial assistance to BPA's customers to develop conservation projects and renewable resources. The Conservation Rate Credit (CRC) is intended to help implement the program goals set forth in BPA's policy for the development of regional conservation and renewable resources. BPA is looking to its customers to be in the vanguard of conservation and renewable resource development in the region. Program goals for both programs were developed as part of Bonneville Power Administration's Policy for Power Supply Role for Fiscal Years 2007-2011 (Near-Term Policy) and accompanying Administrator's Record of Decision (Near-Term Policy ROD). The Near-Term Policy ROD is available at www.bpa.gov/power/pl/regionaldialogue/02-2005_rod.pdf. The structure and program design for the CRC were developed through a collaborative workgroup process. As part of the Regional Dialogue, BPA looked to the collaborative workgroup process to assist in developing a fully defined conservation proposal. The collaborative process started in September 2004 and resulted in the post-2006 conservation program structure. Documentation, WP-10-E-BPA-05A, Appendix B; *see also* Appendices C and D.

BPA's Near-Term Policy expresses five principles to guide the development of conservation acquisition programs for post-2006. In brief, these principles are: (1) use the Northwest Power and Conservation Council's plan to identify the regional cost-effective conservation targets upon which BPA's share (approximately 40 percent) of cost-effective conservation is based; (2) achieve the bulk of the conservation at the local level; (3) meet BPA's conservation goals at the lowest possible cost to BPA; (4) provide an appropriate level of funding for local administrative support to plan and implement conservation programs; and (5) provide an appropriate level of funding for education, outreach, and low-income weatherization such that these important initiatives complement a complete and effective conservation portfolio.

### 2.11.1 Conservation Rate Credit

To encourage its customers to undertake conservation projects and develop renewable resources, BPA would make the CRC available to customers who purchase power under the PF-10 (including the Slice rate but not the PF Exchange rate), IP-10 (except aluminum smelters), and NR-10 rate schedules. Documentation, WP-10-E-BPA-05A, Appendix C.

The discount for the CRC is 0.5 mills/kWh. The 0.5 mills/kWh rate discount was originally established as the WP-02 Conservation and Renewables Discount (C&RD) rate discount. This proposal continues the CRC for FY 2010-2011 rate period at the same rate credit. To estimate the total cost of the CRC, 0.5 mills/kWh is multiplied by the forecast loads purchasing power under the eligible rate schedules. Customers eligible to receive the CRC would not be required to reduce the amount of firm requirements power they purchase from BPA. *Id*. CRC costs are included in the Cost of Service Analysis (COSA) (see WPRDS section 3) as part of conservation program costs.

Customers' monthly BPA power bills would reflect the CRC as a line item. Individual monthly credits on bills would be 0.5 mills/kWh multiplied by one-twelfth of the customer's forecast annual purchases from BPA under its Subscription contract. For Slice customers, the forecast annual purchase would be based on each customer's contractual percentage share of 7,070 aMW. For non-Slice customers, the forecast annual purchases would be based on the forecast of each customer's net requirements as established in the Loads and Resources Study Documentation, WP-10-E-BPA-01A, Sections 2.2.1 and 2.2.2. Each customer's expected series of 24 equal monthly line item credits to its power bill is calculated prior to the FY 2010-2011 rate period. Based on compliance with BPA's Conservation and Renewables Implementation Guidelines, BPA would reserve the right to adjust the specific amount of CRC received by each customer as necessary throughout the rate period. GRSPs, WP-10-E-BPA-07, Section II.A.

The proposal assumes the CRC will generate no net revenue during the rate period and that all eligible customers will participate in the CRC. Participation in the CRC program occurs when customers accept the credit on their monthly bills. As participants, customers accept responsibility to make appropriate expenditures in conservation and renewable resources during the rate period as set forth in BPA's Conservation and Renewables Implementation Guidelines, as amended by establishment of the CRC. Each customer participating in the CRC program will administer its CRC activities pursuant to the most-current CRC Implementation Manual or its successor. Customers may opt out of the CRC program by notifying BPA. BPA will remove the CRC from non-participating customers' monthly bills. *Id*., section II.A.3.b. Consistent with the terms of the customer's Subscription power sales contract with BPA, failure to make the appropriate expenditures will result in the customer reimbursing BPA the difference between the amount of the CRC received and the customer's actual total qualifying expenditures. *Id*., section II.A.3.c.

With help from the Northwest Power and Conservation Council Regional Technical Forum (RTF), criteria to determine qualifying expenditures were established to implement the C&RD and are continuing for the CRC. After several years of practice, BPA and its customers have experience with hundreds of qualifying expenditures, which may, at times, be reassessed to determine their cost and benefit.  For example, BPA may ask the RTF to conduct periodic energy savings performance evaluations at the regional level with appropriate power customer involvement.  These evaluations will assist in the determination of future adjustments to the savings credited for measures and program designs in the CRC.  BPA expects that the list of cost-effective measures will be updated during the rate period to reflect revised cost-effectiveness standards and eliminate measures that are not cost-effective.

Customers participating in the CRC program must submit a final report on qualifying expenditures as required at the end of the customer's discount period.  The discount period is the term of the customer's Subscription power sales contract.  BPA will evaluate the customer's total qualifying expenditures for conservation and renewable option projects during the rate period. When documented total qualifying expenditures are less than the sum of the monthly billing credits for the rate period, customers will be required to reimburse BPA for the difference pursuant to the late payment provision of the Subscription contract.  *Id*.

BPA will account for the energy savings that are produced through the CRC and from BPA-funded participation in Northwest Energy Efficiency Alliance (NEEA) conservation activities for purposes of achieving BPA's share of the Northwest Power and Conservation Council's conservation target.  Such savings will not be reflected as reductions in the customers' firm net requirement loads during the FY 2010-2011 rate period.

Slice and/or Block customers that sign bilateral contracts with BPA obligating the customers to deliver actual energy savings will be required to reduce their firm net requirements loads. Documentation, WP-10-E-BPA-05A, Appendix C.

BPA reserves the right to review the implementation of conservation programs funded through the CRC program. BPA may inspect and/or audit customers to verify claims of units or completed units of conservation and monitor or review utility records and verified energy savings method and results. The number, timing, and extent of such audits shall be at the discretion of BPA. *Id*.

**2.11.2 Renewable Option of the Conservation Rate Credit**

A Renewable Option is included as part of the CRC program. A utility customer participating in the Renewable Option is required to request annual funding for eligible renewable resource activities (as prescribed in the CRC Implementation Manual) at least three months prior to the beginning of each fiscal year of the rate period. When renewable energy option participation requests in the CRC exceed the capped dollar amounts, participants will be subject to *pro rata* reductions. Customers must submit progress reports pursuant to the CRC Implementation Manual or its successor.

**2.12 Green Energy Premium (GEP)**

The GEP is a charge added under applicable rate schedules when a customer chooses to designate any portion (up to 100 percent) of its Subscription purchase as Environmentally Preferred Power (EPP), or its successor, or Alternative Renewable Energy (ARE). GRPSs, WP-10-E-BPA-07, Section II.K. By paying the GEP, BPA’s customers receive the non-power renewable attributes (e.g., Renewable Energy Certificates (RECs)) associated with EPP and ARE. The amount of EPP and ARE that customers may purchase will be limited by availability and the amount of an individual customer’s Subscription firm power purchase. To derive the price of EPP and ARE, BPA will consider the forecast value of environmental attributes expected to be produced by resources included in the portfolio and any contractual call rights for EPP and ARE.

During the FY 2010-2011 rate period, customers and BPA may agree to amend the Subscription contracts to convert the sale of EPP to the sale of RECs. In such event, the language herein that applies to EPP shall apply to RECs.

**2.13 Targeted Adjustment Charge**

Under the proposed PF-10 (with the exception of the PF Exchange rate and the Slice Product) and NR-10 rate schedules, all customer firm power requests for unexpected additional load service that occur after June 30, 2008, will be subject to a Targeted Adjustment Charge (TAC). The TAC would apply for the duration of the rate period. The TAC would be applied to customers that annex load, new public customers requesting requirements service, and retail access load gain or returning load. The TAC would not applied to amounts of power purchased under a customer's initial Subscription contract. For the subsequent rate period (FY 2012-2013), where such load can be incorporated into the load forecast in the WP-12 rate proceeding, the customer would qualify for PF rate service without the TAC.

The TAC will apply to subsequent requests made by a customer under a Subscription contract for requirements service for such customer's load that had been previously served by that customer's own resources as provided under sections 5(b)(1)(A) and (B) of the Northwest Power Act. 16 U.S.C. §§ 839c(b)(1)(A), 839c(b)(1)(B).

BPA may exempt new load from the TAC and apply the PF-10 rate if a public agency customer is annexing or otherwise taking on the obligation of load from another public agency customer in such a manner that BPA's total load obligation does not increase. In this situation, however, the TAC would apply if the annexed requirements load has been previously served by the customer's 5(b)(1)(A) or 5(b)(1)(B) resources, because this would increase BPA's total load obligation.

BPA may exempt any load from the TAC and offer the otherwise applicable rate if the new load is forecast to be less than 1 aMW per year. In this situation, the Administrator may waive the TAC if it is determined to be inconsequential to overall costs.

In a situation where a public agency customer annexes load previously served by an IOU, and such IOU is receiving REP benefits through the Residential Purchase and Sale Agreement (RPSA), the IOU will realize a reduction in the amount of its RPSA benefit payment. BPA would account for such reduced RPSA benefits as an offset against the TAC charged to the public agency customer. The public agency customer would be responsible for any TAC in excess of the amount of the offset.

The TAC would apply for the duration of the customer's contract or through FY 2011, whichever occurs first. If a new public agency customer requests service, the TAC would apply through FY 2011.

For the Initial Proposal, no loads are forecast to be served under a TAC. However, a TAC is included to recover the cost of power purchases, if any, that BPA must undertake to serve unexpected incremental load. The TAC is intended to recover the incremental costs incurred and is not otherwise included in Power Services' revenue requirement for FY 2010-2011. If the cost of power to serve these loads is above BPA's embedded costs, BPA's financial reserves would be affected. The TAC will minimize the erosion of BPA financial reserves that could occur from additional costs to meet unanticipated increases in load.

The TAC would be calculated in response to an individual customer's request and would be determined based on the amount of power available to serve incremental requests from monthly Federal system surplus using critical water conditions, excluding balancing purchases and purchases for System Augmentation included in the resources used to set power rates for the period. This determination will use the monthly available Federal firm system energy that can be used to serve this load. To the extent there is available Federal firm system energy in any month(s), it would be used to serve the TAC load for that month and reduce the total cost of the TAC service.

If sufficient Federal firm system power is available to serve the incremental load, such power shall be sold at the PF-10 rate or the NR-10 rate. In the event sufficient Federal firm system power is not available and BPA must acquire additional power to meet the incremental load, such additional power shall be sold at the PF-10 rate or the NR-10 rate, plus a TAC reflecting the difference between the PF-10 rate or NR-10 rate and BPA's cost to supply this power.

BPA would calculate the total cost of the additional power for a specific customer request based on BPA's estimated monthly cost to purchase resources at market plus an administrative fee, including any additional incurred costs to serve the incremental load. These additional costs may include, where applicable, transmission, ancillary services, losses, and/or other charges incurred in purchasing power from other entities. The Net Present Value (NPV) of the expected PF or NR revenues will be subtracted from the NPV of the total cost, and the remainder will be levelized across the total megawatthours of the incremental load to obtain a levelized mills/kWh charge that will be the TAC rate. That TAC rate will be applied to all energy delivered to the incremental load, even in months where there was sufficient FBS to serve the load.

The TAC rate would not reduce the total price for power below the PF-10 rate or the NR-10 rate, whichever is applicable. The TAC would be applied in addition to the monthly HLH and LLH energy rates, demand rate, and load variance rate for the applicable month or months as specified in the applicable rate schedules.

BPA would calculate the cost basis for a TAC at the time a customer requests power under this schedule. The TAC would be finalized prior to signing a final contract or before initial deliveries of energy, whichever is first.

In order to encourage renewable resource development in the region, BPA would allow a limited exception to the application of the TAC to customers that buy or develop renewable resources. If a customer is serving a portion of its load with either a certifiable renewable resource eligible for the CRC or a contract purchase of certified renewable resource power eligible for the CRC for a period shorter than the FY 2010-2011 rate period, such customer may request additional requirements firm power service during the rate period for such load at the PF-10 rate without being subject to the TAC.

## 2.14 Transfer Services

This transfer service section includes two separate charges that may apply to power customers BPA serves by transfer. These charges, the GTA Delivery Charge and the Transfer Service Operating Reserve Charge, address distinct aspects of Transfer service. This section also addresses the Supplemental Direct Assignment Guidelines applicable to customers purchasing power from BPA by way of transfer service.

### 2.14.1 GTA Delivery Charge

The GTA Delivery Charge is a rate for low-voltage delivery service of Federal power provided under GTAs and other non-Federal transmission service agreements over a third-party transmission system. The GTA Delivery Charge applies to power customers that take delivery at voltages below 34.5 kV when BPA is paying for the transfer service over the third-party transmission system, unless such costs have otherwise been directly assigned to the specific customer.

Since 2002, the GTA Delivery Charge has mirrored Transmission Services' Utility Delivery Charge.  For the FY 2010-2011 rate period, the components of the GTA Delivery Charge are proposed to continue to mirror the Transmission Services' Utility Delivery rate and billing factor under the posted Delivery Charge schedule in the approved transmission and ancillary services rate schedules.  The GTA Delivery Charge would change following a change to the Utility Delivery Charge.

The GTA Delivery Charge revenue forecast is approximately $2.7 million per year, as shown in Table 2.4 below. This revenue forecast was derived by applying the proposed GTA Delivery Charge of $1.119 per kilowatt per month to the forecast peak loads of the customers that pay the GTA Delivery Charge.

**Table 2.4**
**Forecast Revenue from GTA Delivery Charge**

| | FY2010 | FY2011 |
|---|---|---|
| October | $ 181,940 | $ 186,853 |
| November | $ 230,073 | $ 235,936 |
| December | $ 232,763 | $ 238,415 |
| January | $ 260,231 | $ 266,311 |
| February | $ 212,487 | $ 217,664 |
| March | $ 204,597 | $ 209,633 |
| April | $ 222,315 | $ 227,807 |
| May | $ 187,042 | $ 191,312 |
| June | $ 203,273 | $ 208,057 |
| July | $ 211,954 | $ 216,736 |
| August | $ 217,528 | $ 222,522 |
| September | $ 341,706 | $ 350,026 |
| Total | $ 2,705,907 | $ 2,771,271 |

### 2.14.2  Supplemental Direct Assignment Guidelines

In accordance with the July 2007 Regional Dialogue Policy and Record of Decision, BPA is including in this Initial Propsal the Supplemental Guidelines for Direct Assignment of Facilities Costs Incurred Under Transfer Agreements (Supplemental Direct Assignment Guidelines) in the GRSPs for the October 1, 2009, to September 30, 2011, period.  GRSPs, WP-10-E-BPA-07, section I.E. The Supplemental Direct Assignment Guidelines address how BPA would recover the costs for facility expansions and upgrades on third-party transmission systems for transfer service customers. The Supplemental Direct Assignment Guidelines, in conjunction with the Transmission Services' Guidelines for Direct Assignment Facilities, as described in the Transmission Services' Business Practices, would be used to determine whether and in what way to assign specific facility or expansion costs to particular Transfer service customers.

**2.14.3 Transfer Service Operating Reserve Charge**

The proposed Transfer Service Operating Reserve Charge is a new charge that is designed to address a potential change in Operating Reserve obligations. Currently, BPA does not pay Operating Reserves on third-party systems for the transmission of Federal power to transfer service customers, because transfer service customers would have already paid the required Operating Reserve transmission charge. As described in more detail in section 5.3 of the Generation Inputs Study, WP-10-E-BPA-08, the Commission is considering a WECC proposal to change this requirement. The proposed WECC change would reduce the Operating Reserve obligation of the BPA BAA for transfer service customers and shift a portion of the obligation to the balancing authority areas in which transfer service customers reside. This change, if adopted, is expected to result in added BPA expense for Operating Reserve supplied by third-party transmission providers.

The proposed Transfer Service Operating Reserve Charge would recover these additional rate period costs. GTA-10 rate schedule, WP-10-E-BPA-07, section II. In general, the Transfer Service Operating Reserve Charge would mirror Transmission Services' ACS-10 charge for Operating Reserves. The charge would apply to power customers when the following three conditions are met: (1) BPA serves the power customer by transfer; (2) the power customer does not pay Transmission Services for Operating Reserves based on 3 percent of the customer's load; and (3) BPA is assessed Operating Reserve charges from a third-party transmission provider to transfer Federal power to the power customer's load. For customers that meet the above criteria, the Transfer Service Operating Reserve Charge would charge the same rate for Operating Reserves that Transmission Services charges customers that have load in the BPA BAA. The Transfer Service Operating Reserve Charge would begin if and when the proposed change to the Operating Reserve requirements, as described in section 5.3 of the Generation Inputs Study, WP-10-E-BPA-08, is adopted by the Commission and implemented by Tranmission Services.

Because the Commission has not approved the proposed WECC change in Operating Reserve, and no date for its implementation has been established, the forecast revenue associated with the Transfer Service Operating Reserve Charge is zero. In addition, even should the Operating Reserve change become effective, implementation of the Transfer Service Operating Reserve Charge will generally result in no net revenue impact. It is anticipated that the increased revenue from transfer service customers will be offset by the increased ancillary service costs paid to third-party transmission systems.

### 2.15 Slice of the System (Slice) Product, Slice Revenue Requirement, and Slice Rate

#### 2.15.1 Slice Product Description

The Slice product is a sale of a fixed percentage of the generation output of the FCRPS. It is not a sale or lease of any part of the ownership of, or operational rights to, the FCRPS. The Slice product is a power sale based upon a Slice customer's annual net firm requirement load and is shaped to BPA's generation output from the FCRPS. BPA's Subscription sale of the Slice product required a commitment by each Slice customer to purchase the product for 10 years, from FY 2002 through FY 2011.

Because the Slice product is calculated as a percentage of the FCRPS generation output, the actual amount of power delivered to the Slice customer varies throughout the year. During certain periods of the year and under certain water conditions, the power delivered exceeds the Slice customer's net firm requirement and may, at times, exceed the Slice customer's actual firm load. As a consequence, the Slice product entails a sale of both requirements power and surplus power.

### 2.15.2 Slice Revenue Requirement

Each Slice customer pays a percentage of BPA's costs, rather than a set price per megawatt and megawatthour. The Slice customer's obligation to pay is based on the percentage of the FCRPS generation output the Slice customer elected to purchase in its 10-year Subscription contract. The Slice customers pay a percentage of the Slice Revenue Requirement.

### 2.15.3 Inclusion and Treatment of Expenses and Revenue Credits

The Slice Revenue Requirement includes the same expenses and revenue credits that are included in the Power revenue requirement, with certain limited exclusions. In general, there are three types of excluded expenses: (1) power purchases, except those associated with the inventory solution (augmentation); (2) inter-business line transmission costs, except those associated with serving BPA system obligations and GTAs; and (3) Planned Net Revenues for Risk (PNRR) (or successor risk mitigation tools) and hedging expenses, except those hedging expenses associated with the inventory solution. See Table 2.5, Slice Product Costing and True-Up Table, for a detailed list of the line items and forecast dollar amounts in the Slice Revenue Requirement.

The following paragraphs clarify the rate treatment of particular items in the Slice Revenue Requirement and Actual Slice Revenue Requirement. The Slice Revenue Requirement includes all the forecast expenses and revenue credits that are the basis for calculating the Slice rate for FY 2010-2011. The Actual Slice Revenue Requirement will include the same expense and revenue credit categories as the Slice Revenue Requirement, but will be comprised of the final audited actual expenditures and revenues as reflected on BPA's Power Services financial statements, including any adjustments that result from this proceeding. The Actual Slice Revenue Requirement for a given fiscal year is used as the basis for the calculation of the annual Slice True-Up Adjustment Charge for that fiscal year. *See* section 2.15.5 for a more detailed description of the Slice True-Up process.

**2.15.3.1 Augmentation Expenses**

The Initial Proposal includes power purchases to augment the capability of the Federal system to meet the total load placed on BPA. These augmentation power purchases are those needed to meet all load service requests made under BPA's Subscription contracts on a planning basis. For ratemaking purposes, augmentation purchases are considered to be separate and distinct from balancing purchases. See section 3.2.1.2.2 for a description of balancing power purchases. Slice customers do not pay for BPA's balancing purchases, as the Slice customers face the risk of reduced hydro system flexibility directly and have the obligation to serve their own loads on an hourly and monthly basis.

Slice customers are required to pay their proportionate share of the net cost of all augmentation expenses. The "net cost" of augmentation refers to the expenses associated with the purchase of the augmentation power less the associated revenues from the sale of such augmentation power at the PF Preference rate. Slice customers do not receive any of the power associated with these augmentation purchases.

In the Initial Proposal, augmentation expenses during the FY 2010-2011 rate period are forecast for FY 2010 to be $176.58 million, based on $53.34/MWh for 372 aMW of unspecified augmentation. Although not actual augmentation, the augmentation expense also includes plus $30.58/MWh for 10.3 aMW of Excess Requirements Energy (ERE) purchased from Slice customers, as described in section 4.5.1.1. For FY 2011, the forecast augmentation expenses are forecast to be $304.818 million, based on $57.70/MWh for 599 aMW of unspecified augmentation plus $30.96/MWh for 7.6 aMW of ERE purchased from Slice customers. *Id.*

The revenues associated with the sale of augmentation power are estimated based on the projected PF Preference rate for power and multiplied by the amount of power that would be sold (382.3 aMW for FY 2010 and 606.6 aMW for FY 2011). The PF Preference rate is assumed to be $29.43/MWh for FY 2010-2011 (this is an average PF rate for Initial Proposal purposes and is not final). BPA subtracts the expected revenues from the forecast purchase expense to calculate the net cost of the augmentation purchases for FY 2010-2011. The net cost of augmentation power for FY 2010-2011 will not be subject to the Slice True-Up process, except for adjustments included in the WP-10 Final Proposal.

**2.15.3.2 Conservation Augmentation**

Conservation Augmentation (ConAug) was the conservation component of BPA's inventory solution in the WP-02 Final Proposal. ConAug was a resource acquisition effort to purchase conservation measures to reduce BPA's load obligation.

The annual costs of ConAug were estimated and included in the augmentation expenses for the FY 2002-2006 Slice Revenue Requirement. Since it was not known specifically during the WP-02 rate proceeding how the ConAug program would be implemented, the annual costs were derived as if the load reduction was equivalent to a power purchase. The estimate of ConAug costs was based on the assumption that 20 aMW of ConAug would be purchased each year during FY 2002-2006. The cost of this power was estimated to be 28.1 mills/kWh plus 10 percent, or 30.9 mills/kWh, and was included as part of the Slice Revenue Requirement.

In the WP-02 Final Proposal, BPA set the ConAug expense as a fixed amount that was not subject to the Slice True-Up. This fixed amount was limited to the first 20 aMW of ConAug acquired each year during FY 2002-2006. Slice customers paid their share of the estimated costs of 100 aMW of ConAug during FY 2002-2006. If BPA acquired more than 20 aMW during any given year, those costs were allocated through the Load-Based Cost Recovery Adjustment Clause (LB CRAC) and included in related charges to both Slice and non-Slice customers.

BPA decided to capitalize the costs of actual ConAug acquisitions subsequent to the WP-02 Supplemental Final Proposal. As a result, there are annual amortization expenses associated with ConAug investments from FY 2002-2006 that carry over into FY 2010-2011. See the Revenue Requirement Study Documentation, WP-10-E-BPA-02A, Table 3F. These investments are amortized over the term of the Subscription contracts and are not fully amortized until 2011. However, Slice customers will not pay for these ConAug amortization costs in FY 2010-2011 because Slice customers paid a forecast of ConAug costs as if they were incurred as annual expenses. Therefore, the amortization is excluded from the Slice Revenue Requirement and the Actual Slice Revenue Requirement for FY 2010-2011.

#### 2.15.3.3 IOU Residential Exchange Program (REP) Benefits

Slice customers are obligated to pay their proportionate share of the net expenses associated with the IOU Residential Exchange Program. The WP-07 Supplemental Final Proposal resulted in a restart of the IOU REP beginning October 1, 2008. Consistent with the Slice Rate Methodology, the net costs of REP benefits (gross exchange costs minus gross PF Exchange rate revenues) will be included in the Slice Revenue Requirement; see Table 2.5, line 29. The net costs of IOU REP benefits are based on a prior adjustment for the return of Lookback Amounts to Slice customers. See section 2.15.5 and the Lookback Recovery and Return Study, WP-10-E-BPA-09, for discussions of the return of Lookback Amounts to Slice customers.

**2.15.3.4 Cost of the Residential Exchange for COUs**

Slice customers are responsible for paying their proportionate share of the net cost of the REP benefits for consumer-owned utilities (COUs). The net cost of the REP benefits for COUs is calculated by subtracting the gross exchange revenues from the gross exchange expenses. An amount of net costs of the REP for COUs was forecast for FY 2010-2011 and included in the Slice Revenue Requirement, as shown on Table 2.5, line 28. The actual net costs of the REP for COUs in any year will be included in the Actual Slice Revenue Requirement for that year for purposes of calculating the Slice True-Up.

**2.15.3.5 Bad Debt Expense**

The Slice Revenue Requirement contains a line item labeled "Bad Debt Expense," based on the line item in Power Services' Statement of Revenues and Expenses. No amounts are forecast for bad debt expense for FY 2010-2011. However, the Actual Slice Revenue Requirement may contain an actual amount accounted for as bad debt expense. In the Actual Slice Revenue Requirement, for Slice True-Up purposes, any bad debt expense associated with the sale to any customer that purchases exclusively at the FPS-10 rate would be excluded from the Actual Slice Revenue Requirement. However, any bad debt expense associated with the sales to customers who purchase power at both the PF-10 and FPS-10 rates, along with any bad debt expense associated with the sales to customers who purchase power at the PF-10 rate only, would be included in the Actual Slice Revenue Requirement. These treatments are consistent with what was adopted in the Partial Resolution of Issues in the WP-07 rate case. WP-07-A-02, Attachment 1. Through the annual Slice True-Up, Slice customers will pay their proportionate share of the eligible bad debt expenses.

BPA reversed the True-Up Adjustment charges to Slice customers for the bad debt expense arising out of transactions with the CAISO and California Power Exchange (Cal PX) prior to October 1, 2001. As a result, Slice customers will not receive any credit for recovery of any related outstanding receivables that BPA collects. Nor will the Slice customers pay for any future bad debt expense related to write-offs of any outstanding CAISO or Cal PX receivables. This treatment is specified by the Slice Settlement Agreement (07PB-12273). The Slice Settlement Agreement is effective through September 30, 2011.

Allowances for uncollectible DSI liquidated damages for FY 2002 or prior years will not be included in the Actual Slice Revenue Requirement or Slice True-Up Adjustment Charge. Slice customers will not receive credit for recovery of receivables that BPA collects from DSIs. This treatment is specified by the Slice Settlement Agreement.

**2.15.3.6 Costs of DSI Service**

On June 30, 2005, BPA's Administrator signed the Record of Decision *Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011* (DSI ROD). In this decision, the Administrator determined that BPA would offer 560 aMW of service benefits to the aluminum smelters, capped at an annual cost of $59 million, plus 17 aMW of power to Port Townsend Paper Corporation, for FY 2007-2011. These service benefits were provided to the aluminum smelters through monthly payments. The annual amounts of such service benefits were included in the Slice Revenue Requirement and subject to the annual Slice True-Up. Slice customers paid their proportionate share of the costs associated with these service benefits to the DSIs.

In December 2008, the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit) issued a decision in *Pacific Northwest Generating Cooperative et al. v. Department of Energy, slip op.*, Case No. 05-75638 at 16513 (9th Cir. 2008), that rejected aspects of the contractual arrangements for service benefits to the DSIs. For purposes of the WP-10 Initial Proposal, the Slice Revenue Requirement includes the net cost, $58.9 million, for service to the aluminum smelters, plus a sale to Port Townsend Paper of 17 aMW. The Initial Proposal includes the net cost of DSI sales, which is the difference between additional power costs and revenues at the IP rate. Table 2.5, line 17. To the extent that there is greater certainty regarding the manner and method of service to the DSIs between now and the WP-10 Final Proposal, the final studies will reflect the cost of this service . Slice customers will pay their proportionate share of these costs, which will be included in the Slice Revenue Requirement.

**2.15.3.7 Fish and Wildlife Program Costs**

Slice customers are obligated to pay their proportionate share of BPA's costs for fish and wildlife, both BPA's direct program costs and U.S. Army Corps of Engineers and U.S. Bureau of Reclamation costs. Slice customers will also experience their proportionate share of BPA's indirect, or operational, program costs for fish and wildlife directly, through reduced or changed Slice power deliveries.

If BPA's fish and wildlife obligations differ from the forecasts contained in the Slice Revenue Requirement, Slice customers will pay their proportionate share of any increase or decrease in fish and wildlife annual expenses through their annual True-Up. Slice customers would be affected in real time for any changes in indirect program costs (e.g., changed operations or increases in spill and flow) for fish and wildlife through changes in their Slice power deliveries.

**2.15.3.8 Slice Implementation Expenses**

Slice Implementation Expenses are defined as those costs reasonably incurred by Power Services in any Contract Year (same as BPA's fiscal year) for the sole purpose of implementing the Slice product and that would not have been incurred had BPA not sold Slice Output under the Block and Slice Power Sales Agreement. Therefore, if BPA incurs costs during any Contract Year solely for the purpose of implementing the Slice product, these expenses would be charged 100 percent to the Slice customers through the annual Slice True-Up.

Consistent with BPA's Software Capitalization Policy and Personal Property Capitalization Policy, any hardware or software acquired for the Slice Computer Application Project and for implementing the Block/Slice Power Sales Agreement will be capitalized over the shorter of a five-year period or the remainder of the Block/Slice contract term, which ends on September 30, 2011.

Slice Implementation Expenses in any given Contract Year will be accounted after the audited year-end Actual Slice Revenue Requirement is available for that Contract Year. Slice Implementation Expenses will be charged to Slice customers through the annual Slice True-Up for that Contract Year.

**2.15.3.9 Debt Optimization Program**

Through the Debt Optimization Program, BPA refinances (i.e., extends the maturities of) Energy Northwest bonds as they come due and repays an equivalent amount of Federal debt. In total, the same amount of debt is repaid as scheduled through the ratesetting process, but with an emphasis toward repaying Federal debt rather than non-Federal debt. See Revenue Requirement Study, WP-10-E-BPA-02, section 2.3.

The financial effects from the refinancing and the related additional amortization of Federal debt are properly and fully accounted in the Actual Slice Revenue Requirement, in accordance with the manner in which they are accounted for in Power Services' statement of revenues and expenses and in the determination of business line financial reserves.

The Debt Optimization Program is a BPA debt management policy that affects not only the Slice rate (through the annual True-Up Adjustment Charge), but BPA's rates of general application through the implementation of the CRAC. Inclusion of the Debt Optimization Program transactions in the annual True-Up Adjustment Charge is recognition of the Slice customers' share of these obligations.

**2.15.3.10 Reinvestment of "Green Tag Revenues" in BPA's Renewable Resources Facilitation and Research and Development**

BPA will reinvest what it collectively refers to as "Green Tag revenues" in BPA's renewable resource facilitation and in renewables research and development. These Green Tag revenues come from three sources: (1) Green Energy Premium revenues resulting from sales of Environmentally Preferred Power; (2) Green Tag revenues resulting from sales of Renewable Energy Certificates; and (3) revenues from sales of Alternative Renewable Energy to pre-Subscription power purchasers. The renewables expense associated with the reinvestment of "Green Tag revenues" would be excluded from the Slice Revenue Requirement and the Actual Slice Revenue Requirement, consistent with the treatment adopted in the Partial Resolution of Issues in the WP-07 rate case, WP-07-A-02, Attachment 1.

**2.15.3.11 Revenues from Generation Inputs for Integration of Wind Generation**

Power Services will provide to Transmission Services the within-hour balancing requirements needed for wind generation (which includes regulation, load following, and generation imbalance). These requirements for wind generation are expected to significantly increase Power Services' provision of generation inputs to Transmission Services as the projected amounts of wind generation come on line in the next few years.

Power Services projects that the inter-business line revenues from its provision of within-hour balancing services for wind generation will be $180.5 million in FY 2010 and $215.8 million in FY 2011. These estimates represent a significant increase over historical amounts of inter-business line revenues that Power Services has received for its provision of generation inputs for ancillary and other services. Slice customers will receive their proportionate share of the actual amount of such revenues through the Slice True-Up. The inter-business line revenues that will result from Power Services' provision of the within-hour balancing services for wind generation have been adjusted downward by $34.6 million in each year of the FY 2010-2011 rate period for the determination of the Slice rate for the WP-10 Initial Proposal; this adjustment will be removed from the Final Proposal.

These generation inputs related to within-hour balancing services for wind generation are considered a system obligation for Slice operational purposes. The WP-02 rate case determined that Slice customers are responsible for bearing a proportionate share of Power Services' costs associated with system obligations. WP-02-FS-BPA-05, Appendix C, section 4.5. The Slice customers are therefore entitled to a credit based on a proportionate share of any revenues associated with the system obligations.

**2.15.3.12 Minimum Required Net Revenue Calculation**

Minimum Required Net Revenue (MRNR) is a component of the annual Generation Revenue Requirement. See the Revenue Requirement Study, WP-10-E-BPA-02, section 4.1.2 for a description of MRNR. MRNR also is a component of the Slice Revenue Requirement. BPA determined that the annual amounts for MRNR in the Slice Product Costing and True-Up Table should be different from the amounts that appear in the total Generation Revenue Requirement. Revenue Requirement Study, WP-07-FS-BPA-13, section 9.4.11, at 138-139. The differences are due to one element in the MRNR calculations. In the total Generation Revenue Requirement, accrual revenues that are included in the revenue forecast must be taken into account. Since these are non-cash revenues, the MRNR calculation must adjust cash from current operations to ensure adequate coverage of the annual cash requirements in order to demonstrate full cost recovery for proposed power rates. Revenue Requirement Study, WP-10-E-BPA-02, section 4.1.2. These accrual revenues stem from a settlement in which Power Services received cash payments that, in the accounting treatment, are recognized as revenues on a straight-line basis over the remainder of the term of the settled contracts. However, these settlements and the associated accrual revenues are not relevant to cost recovery for Slice and do not appear in the calculation of MRNR for the Slice Revenue Requirement. Due to this difference, the MRNR in the Slice Revenue Requirement is smaller than the MRNR in the total Generation Revenue Requirement.

**2.15.4 Slice Rate**

The Slice Revenue Requirement is the basis for calculating the base Slice rate. To calculate the proposed Slice rate for FY 2010-2011, the total dollar amounts for each fiscal year of the Slice Revenue Requirement are summed and divided by 24 months (the number of months in the rate period) and divided by 100 to obtain the base Slice rate per percent of Slice product purchased. See Table 2. 5, Slice Product Costing and True-Up Table. The proposed monthly Slice rate for FY 2010-2011 is $2,049,762 per one percent Slice product purchased.

**2.15.5 Slice True-Up**

Because the Slice rate is calculated as a uniform monthly rate for the rate period and does not take into account the variability of actual costs from year to year, BPA will true up the difference between the expenses and credits in the average Slice Revenue Requirement for the applicable rate period upon which the Slice rate is based and the actual expenses and credits in the Actual Slice Revenue Requirement for the applicable fiscal year. The Actual Slice Revenue Requirement for the applicable fiscal year is the sum of the final audited expenditures and revenues as reflected on BPA's Power Services financial statements, corresponding to those Power Services expense and revenue categories that are included in the Slice Revenue Requirement. BPA's financial statements contain expenses and credits that are in accordance with Generally Accepted Accounting Principles (GAAP). Any difference between the Actual Slice Revenue Requirement and the average Slice Revenue Requirement is called the Slice True-Up Amount. The True-Up Amount calculation is the Actual Slice Revenue Requirement for the applicable fiscal year minus the average Slice Revenue Requirement for the applicable rate period.

A positive or negative result from the True-Up Amount calculation will result in a charge or credit to the Slice customer. The Slice True-Up Amount is then multiplied by each customer's Slice percentage to calculate the Slice True-Up Adjustment Charge (or Credit) for each customer. See section 2.15.6 for the forecast total Slice True-Up Adjustment Charges (or Credits) for FY 2010-2011. Because of the Slice True-Up Adjustment Charge (or Credit), Slice customers pay a percentage of BPA's actual costs, regardless of weather, streamflow, market, or generation output conditions. This ensured payment of actual costs mitigates BPA's financial risks in the event that any adverse or beneficial conditions change BPA's financial condition. The Slice customers' payments through their base Slice rate and the annual True-Up Adjustment Charge mitigate the risk associated with the variability of BPA's expenses and revenue credits (for those expenses included in the Slice Revenue Requirement). The risks associated with the variability of generation output and with the uncertainty of market prices for purchasing or selling power are assumed directly by the Slice customers.

In the WP-07 Supplemental Final Proposal, BPA decided to return the FY 2002-2006 Lookback Amounts related to the REP settlement expenses as a credit on the Slice customers' power bills. 2007 Supplemental Wholesale Power Rate Case Administrator's Final Record of Decision, WP-07-A-05, at 282. BPA stated that it will ensure that Slice customers do not receive any additional payments for the return of Lookback Amounts through the Slice True-Up process. *Id.* at 281. Applicable Lookback Amounts are returned as a credit on the Slice customers' power bills during the FY 2010-2011 period. Therefore, in order to ensure that that Slice customers do not receive any additional payments for the return of Lookback Amounts through the Slice True-Up process for FY 2010 and FY 2011, BPA will account for these credits on Slice customers' power bills when calculating the Slice True-Up Adjustment Charge for customers for FY 2010 and FY 2011.

**2.15.6 Forecast Slice True-Up Adjustment Charge and Related Potential Cost Shift**

During the preparation of the Initial Proposal, staff identified a potential cost shift related to the forecast Slice True-Up Adjustment Charge. BPA staff initially forecast a Slice True-Up Adjustment Charge owed by the Slice customers to BPA of approximately $20 million in FY 2011. WPRDS Documentation, Vol. 1, WP-10-E-BPA-5A. Under the Slice Rate Methodology, the Slice customers make this cash payment to BPA in early FY 2012, beyond the term of this rate period. A consequence of the receipt of the cash payments in FY 2012 is that this cash cannot be considered available to BPA for purposes of calculating the Treasury Payment Probability (TPP). Analyses indicated that the time lag in the receipt of these cash payments results in additional PNRR in the non-Slice revenue requirement, in order to meet the 95 percent TPP standard. Because the Slice Revenue Requirement does not include any PNRR, a potential cost shift exists because the PNRR that non-Slice customers could be required to pay is higher than it would have been without a forecast Slice True-Up Adjustment Charge for FY 2011.

The forecast of a Slice True-Up Adjustment Charge in FY 2011 arises because of recent changes in the way the Slice True-Up Adjustment Charge is calculated. BPA agreed, as part of the Slice Settlement Agreement (07PB-12273), to calculate the Slice True-Up Adjustment Charge by comparing the Actual Slice Revenue Requirement to the rate-period average Slice Revenue Requirement. Section 2.15.5 describes the Slice True-Up calculation. FY 2002-2008 Lookback Study, WP-07-FS-BPA-08, section 9.4.3 describes the Slice Settlement Agreement. Because the initial proposal forecast of the FY 2011 Slice Revenue Requirement is much larger than the FY 2010 Slice Revenue Requirement, the change to a Slice True-Up calculation based on a comparison of the Actual Slice Revenue Requirement with the rate-period average Slice Revenue Requirement results in a forecast of a Slice True-Up Adjustment Charge in FY 2011. A second reason behind the forecast of a Slice True-Up Adjustment Charge in FY 2011 involved the forecast of Slice Implementation Expenses. WPRDS, WP-10-E-BPA-05, section 2.15.3.8 describes Slice Implementation Expenses. Slice Implementation Expenses are forecast, but not included in the Slice Revenue Requirement. The Slice Implementation Expenses are collected as an add-on amount to the Slice True-Up Adjustment Charge. Because there is a forecast of Slice Implementation Expenses in FY 2011, this ensures that there will be a nonzero FY 2011 Slice True-Up Adjustment Charge.

Staff proposes to address the potential cost shift by moving portions of certain cost categories in the Slice Revenue Requirement from FY 2011 to FY 2010 so that the forecast of the FY 2011 Slice True-Up Adjustment Charge is zero. When the forecast of the FY 2011 Slice True-Up Adjustment Charge is zero, there is no related cash payment that lags outside of the rate period, and there is no compensatory increase in PNRR in the non-Slice revenue requirement.

Staff identified two expense categories to shift from FY 2011 to FY 2010 -- a portion of net augmentation expenses and a portion of BPA's planned principal payment for Power Services' Federal debt, which is an element in the calculation of the Minimum Required Net Revenue (MRNR) component of the Slice Revenue Requirement. The shift in BPA's principal payments for Federal debt for Power Services is described in the Revenue Requirement Study, WP-10-E-BPA-02, section 1.

As a result of the shifting of these expenses, the forecast of Slice True-Up Adjustment Charge for FY 2010 is $5,660,000, which represents a charge to Slice customers, and $0 for FY 2011. The amount of the Slice True-Up Adjustment Charge forecast for FY 2010 is comprised of two years of Slice Implementation Expenses that are assumed, for purposes of initial proposal rate analyses, to be collected in FY 2010. If actual audited expenses or revenue credits, other than net augmentation costs, differ from expenses and revenue credits forecast in the Slice Revenue Requirement, there could be Slice True-Up Adjustment Charges that are different from the forecast. A Slice True-Up Adjustment Charge that was not forecast, but is calculated when audited financial data becomes available, would not cause a cost shift. The cost shift issue only arises from Slice True-Up Adjustment Charges that are forecast in the rate case and therefore have an effect on PNRR in the TPP calculations. If a Slice True-Up Adjustment Charge is forecast to be $0, there will be no impact on PNRR. If later calculations show that there actually will be a Slice True-Up Adjustment Charge, PNRR will already have been set and will therefore not be affected by the actual Charge, and there would not be a cost shift.

### 2.15.7 Changes to the Methodology to Calculate Slice Rate and Slice True-Up Adjustment Charge (Slice Rate Methodology)

Several minor updates to the Slice Rate Methodology are proposed to avoid confusion during FY 2010-2011. The first change is to section 4.A. Language in section 4.A. would be updated to reflect references to the FY 2010-2011 rate period. The second change is to section B.1. Language in section B.1. would be updated to reflect the reference to the two-year rate period. There are other minor changes that reflect updated references to the WP-10 rate case that occur in various places in the Slice Rate Methodology.

# Table 2.5 Slice Product Costing and True-Up Table

| | ($000s) | Audited Actual Data | FY 2010 forecast | FY 2011 forecast |
|---|---|---|---|---|
| 1 | **Operating Expenses** | | | |
| 2 | **Power System Generation Resources** | | | |
| 3 | **Operating Generation** | | | |
| 4 | COLUMBIA GENERATING STATION (WNP-2) | | $ 269,200 | $ 365,000 |
| 5 | BUREAU OF RECLAMATION | | $ 87,700 | $ 98,550 |
| 6 | CORPS OF ENGINEERS | | $ 193,000 | $ 197,911 |
| 7 | LONG-TERM CONTRACT GENERATING PROJECTS | | $ 31,889 | $ 32,343 |
| 8 | **Sub-Total** | | **$ 581,789** | **$ 693,804** |
| 9 | **Operating Generation Settlement Payment** | | | |
| 10 | COLVILLE GENERATION SETTLEMENT | | $ 21,328 | $ 21,754 |
| 11 | **Sub-Total** | | **$ 21,328** | **$ 21,754** |
| 12 | **Non-Operating Generation** | | | |
| 13 | TROJAN DECOMMISSIONING | | $ 2,200 | $ 2,300 |
| 14 | WNP-1&3 DECOMMISSIONING | | $ 418 | $ 428 |
| 15 | **Sub-Total** | | **$ 2,618** | **$ 2,728** |
| 16 | **Contracted Power Purchases** | | | |
| 17 | COST OF DSI SERVICE | | $ 58,867 | $ 58,867 |
| 18 | HEDGING/MITIGATION (omit except for those assoc. with inventory solution) | | $ - | $ - |
| 19 | PNCA HEADWATER BENEFITS | | $ 2,042 | $ 2,620 |
| 20 | GROSS OTHER POWER PURCHASES (short term - omit) | | | |
| 21 | **Sub-Total** | | **$ 60,909** | **$ 61,487** |
| 22 | **Bookout Adjustment to Power Purchases (omit)** | | | |
| 23 | **Augmentation Power Purchases (omit - calculated below)** | | | |
| 24 | AUGMENTATION POWER PURCHASES (omit) | | | |
| 25 | CONSERVATION AUGMENTATION (omit) | | | |
| 26 | **Sub-Total** | | **$ -** | **$ -** |
| 27 | **Exchanges and Settlements** | | | |
| 28 | PUBLIC RESIDENTIAL EXCHANGE | | $ 11,974 | $ 7,495 |
| 29 | IOU RESIDENTIAL EXCHANGE | | $ 253,883 | $ 258,798 |
| 30 | OTHER SETTLEMENTS | | $ - | $ - |
| 31 | **Sub-Total** | | **$ 265,857** | **$ 266,293** |
| 32 | **Renewable Generation** | | | |
| 33 | RENEWABLES R&D | | $ 4,833 | $ 6,092 |
| 34 | RENEWABLES CONSERVATION RATE CREDIT | | $ 4,000 | $ 2,500 |
| 35 | RENEWABLES (excludes expenses from reinvested revenues) | | $ 31,715 | $ 32,306 |
| 36 | **Sub-Total** | | **$ 40,548** | **$ 40,898** |
| 37 | **Generation Conservation** | | | |
| 38 | GENERATION CONSERVATION R&D | | | |
| 39 | DSM TECHNOLOGIES | | $ 1,600 | $ 1,600 |
| 40 | CONSERVATION ACQUISITION | | $ 14,000 | $ 14,000 |
| 41 | LOW INCOME WEATHERIZATION & TRIBAL | | $ 5,000 | $ 5,000 |
| 42 | ENERGY EFFICIENCY DEVELOPMENT | | $ 20,500 | $ 20,500 |
| 43 | LEGACY | | $ 1,988 | $ 1,622 |
| 44 | MARKET TRANSFORMATION | | $ 12,000 | $ 12,000 |
| 45 | **Sub-Total** | | **$ 55,088** | **$ 54,722** |
| 46 | **Conservation and Renewable Discount (C&RD)** | | | |
| 47 | CONSERVATION RATE CREDIT | | $ 32,000 | $ 32,000 |
| 48 | CONSERVATION AND RENEWABLE DISCOUNT | | | |
| 49 | **Sub-Total** | | **$ 32,000** | **$ 32,000** |
| 50 | **Power System Generation Sub-Total** | | **$ 1,060,137** | **$ 1,173,686** |
| 51 | **Power Services Transmission Acquisition and Ancillary Services** | | | |
| 52 | **Transmission Acquisition and Ancillary Services** | | | |
| | | | | |
| 53 | TRANSMISSION & ANCILLARY SERVICES | | | |
| 54 | Canadian Entitlement Agreement Transmission Expenses | | $ 27,000 | $ 27,000 |
| 55 | PNCA & NTS Transmission and System Obligaton Expenses | | $ 1,000 | $ 1,000 |
| 56 | 3RD PARTY GTA WHEELING | | $ 50,690 | $ 51,340 |
| 57 | 3RD PARTY TRANS & ANCILLARY SVCS | | | |
| 58 | GENERATION INTEGRATION | | $ 6,800 | $ 6,800 |
| 59 | TELEMETERING/EQUIP REPLACEMT | | $ 50 | $ 50 |
| 60 | **Power Services Trans Acquisition and Ancillary Serv Sub-Total** | | **$ 85,540** | **$ 86,190** |

## Table 2.5 continued, Slice Product Costing and True-Up Table

($000s)

| | | Audited Actual Data | FY 2010 forecast | FY 2011 forecast |
|---|---|---|---|---|
| 61 | | | | |
| 62 | **Power Non-Generation Operations** | | | |
| 63 | **System Operations** | | | |
| 64 | SYSTEM OPERATIONS R&D | | $ - | $ - |
| 65 | EFFICIENCIES PROGRAM (excludes TMS expenses) | | $ - | $ - |
| 66 | INFORMATION TECHNOLOGY | | $ 6,359 | $ 6,324 |
| 67 | GENERATION PROJECT COORDINATION | | $ 7,892 | $ 8,118 |
| 68 | SLICE IMPLEMENTATION (omit - calculated separately) | | | |
| 69 | **Sub-Total** | | **$ 14,251** | **$ 14,442** |
| 70 | **Scheduling** | | | |
| 71 | SCHEDULING R&D | | | |
| 72 | OPERATIONS SCHEDULING | | $ 9,999 | $ 10,350 |
| 73 | OPERATIONS PLANNING | | $ 6,207 | $ 6,473 |
| 74 | **Sub-Total** | | **$ 16,206** | **$ 16,823** |
| 75 | **Marketing and Business Support** | | | |
| 76 | SALES & SUPPORT | | $ 19,391 | $ 19,617 |
| 77 | Contractual exclusion | | $ (5,360) | $ (5,360) |
| 78 | Implementation Expense Exclusions - Add back | | | |
| 79 | PUBLIC COMMUNICATION & TRIBAL LIAISON | | | |
| 80 | STRATEGY, FINANCE & RISK MGMT | | $ 17,151 | $ 17,632 |
| 81 | EXECUTIVE AND ADMINISTRATIVE SERVICES | | $ 3,645 | $ 5,320 |
| 82 | CONSERVATION SUPPORT (EE staff costs) | | $ 9,359 | $ 9,947 |
| 83 | **Sub-Total** | | **$ 44,186** | **$ 47,156** |
| 84 | **Power Non-Generation Operations Sub-Total** | | **$ 74,643** | **$ 78,421** |
| 85 | **Fish and Wildlife/USF&W/Planning Council/Environmental Req** | | | |
| 86 | **BPA Fish and Wildlife (includes F&W Shared Services)** | | | |
| 87 | FISH & WILDLIFE | | $ 230,000 | $ 236,000 |
| 88 | **Sub-Total** | | **$ 230,000** | **$ 236,000** |
| 89 | **USF&W Lower Snake Hatcheries** | | | |
| 90 | USF&W LOWER SNAKE HATCHERIES | | $ 23,600 | $ 24,480 |
| 91 | **Planning Council** | | | |
| 92 | PLANNING COUNCIL | | $ 9,641 | $ 9,838 |
| 93 | **Environmental Requirements** | | | |
| 94 | ENVIRONMENTAL REQUIREMENTS | | $ 300 | $ 300 |
| 95 | **Fish and Wildlife/USF&W/Planning Council Sub-Total** | | **$ 263,541** | **$ 270,618** |
| 96 | **General and Administrative/Shared Services** | | | |
| 97 | **Additional Post-Retirement Contribution** | | | |
| 98 | ADDITIONAL POST-RETIREMENT CONTRIBUTION | | $ 15,598 | $ 16,071 |
| 99 | **BPA Internal Support - G&A and Shared Srv. (excludes direct project support)** | | | |
| 100 | AGENCY SERVICES G&A | | $ 51,877 | $ 52,270 |
| 101 | **Sub-Total BPA Internal Support Services** | | **$ 51,877** | **$ 52,270** |
| 102 | **Supply Chain - Shared Services** | | | |
| 103 | **General and Administrative/Shared Services Sub-Total** | | **$ 67,475** | **$ 68,341** |
| 104 | **Bad Debt Expense** | | $ - | $ - |
| 105 | **Other Income, Expenses, Adjustments** | | **$ -** | **$ -** |
| 106 | **Non-Federal Debt Service** | | | |
| 107 | **Energy Northwest Debt Service** | | | |
| 108 | COLUMBIA GENERATING STATION DEBT SVC | | $ 234,333 | $ 227,762 |
| 109 | WNP-1 DEBT SVC | | $ 163,171 | $ 165,072 |
| 110 | WNP-3 DEBT SVC | | $ 139,704 | $ 164,849 |
| 111 | EN RETIRED DEBT | | | |
| 112 | EN LIBOR INTEREST RATE SWAP | | | |
| 113 | **Sub-Total** | | **$ 537,208** | **$ 557,683** |
| | | | | |
| 114 | **Non-EN Debt Service** | | | |
| 115 | COWLITZ FALLS DEBT SVC | | $ 11,566 | $ 11,563 |
| 116 | N. WASCO DEBT SVC | | $ 2,200 | $ 2,196 |
| 117 | TROJAN DEBT SVC | | $ - | $ - |
| 118 | CONSERVATION DEBT SVC | | $ 5,079 | $ 4,924 |
| 119 | **Sub-Total** | | **$ 18,845** | **$ 18,683** |
| 120 | **Non-Federal Debt Service Sub-Total** | | **$ 556,053** | **$ 576,366** |
| 121 | **Depreciation (excludes TMS)** | | $ 118,616 | $ 119,920 |
| 122 | **Amortization (excludes ConAug amortization)** | | $ 65,783 | $ 73,654 |
| 123 | **Total Operating Expenses** | | **$ 2,291,788** | **$ 2,447,196** |

## Table 2.5 continued, Slice Product Costing and True-Up Table

**($000s)**

| | | Audited Actual Data | FY 2010 forecast | FY 2011 forecast | |
|---|---|---|---|---|---|
| 124 | | | | | |
| 125 | **Other Expenses** | | | | |
| 126 | Net Interest Expense | | $ 165,823 | $ 171,720 | |
| 127 | LDD | | $ 28,303 | $ 28,646 | |
| 128 | Irrigation Rate Mitigation Costs | | $ 12,036 | $ 12,036 | |
| 129 | **Sub-Total** | | **$ 206,162** | **$ 212,402** | |
| 130 | **Total Expenses** | | **$ 2,497,950** | **$ 2,659,598** | |
| 131 | | | | | |
| 132 | **Revenue Credits** | | | | |
| 133 | Ancillary and Reserve Service Revs. Total | | $ 180,452 | $ 215,811 | |
| 134 | Downstream Benefits and Pumping Power | | $ 8,921 | $ 8,921 | |
| 135 | 4(h)(10)(c) | | $ 88,705 | $ 89,975 | |
| 136 | Colville and Spokane Settlements | | $ 4,600 | $ 4,600 | |
| 137 | FCCF | | | | |
| 138 | Energy Efficiency Revenues | | $ 20,500 | $ 20,500 | |
| 139 | Miscellaneous | | $ 3,420 | $ 3,420 | |
| 140 | Ad Hoc revenue credit adjustment | | $ (34,620) | $ (34,620) | |
| 141 | **Total Revenue Credits** | | **$ 271,978** | **$ 308,607** | |
| 142 | **Augmentation Costs** | | | | |
| 143 | **Forecasted Gross Augmentation Costs** | | | | |
| 144 | Augmentation cost | | $ 176,580 | $ 304,818 | |
| 145 | Minus revenues 382.3 aMW, 606.6 aMW | | $ 98,560 | $ 156,386 | |
| 146 | **Net Cost of Augmentation** | | **$ 131,144** | **$ 95,308** | |
| 147 | | | | | |
| 148 | | | | | |
| 149 | **Minimum Required Net Revenue calculation** | | | | |
| 150 | Principal Payment of Fed Debt for Power | | $ 267,264 | $ 161,888 | |
| 151 | Irrigation assistance | | $ - | $ - | |
| 152 | Depreciation | | $ 118,616 | $ 119,920 | |
| 153 | Amortization | | $ 79,118 | $ 86,989 | |
| 154 | Capitalization Adjustment | | $ (45,937) | $ (45,937) | |
| 155 | Bond Premium Amortization | | $ 185 | $ 185 | |
| 156 | Principal Payment of Fed Debt exceeds non cash expenses | | $ 115,282 | $ 731 | |
| 157 | Minimum Required Net Revenues | | **$ 115,282** | **$ 731** | |
| 158 | | | | | **2-Year Total Rev** |
| 159 | Annual Slice Revenue Requirement (Amounts for each FY) | | **$ 2,472,398** | **$ 2,447,030** | **$ 4,919,429** |
| 160 | | | | | |
| 161 | SLICE TRUE-UP ADJUSTMENT CALCULATION | | | | |
| 162 | | | | | |
| 163 | FY 2010-2011 Average Slice Revenue Requirement determined in WP-10 rate case | | **$ 2,459,714** | | |
| 164 | TRUE UP AMOUNT (Diff. between actual Slice Rev Reqt and forecast average Slice Rev Reqt) | | | | |
| 165 | AMOUNT BILLED (22.6278 percent) | | | | |
| 166 | Slice Implementation Expenses (not incl. in base rate) | | | | |
| 167 | TRUE UP ADJUSTMENT | | | | |
| 168 | | | | | |
| 169 | | | | | |
| 170 | **SLICE RATE CALCULATION ($)** | | | | |
| 171 | **Monthly Slice Revenue Requirement (2-Year total divided by 24 months)** | | | | **$ 204,976,202** |
| 172 | **One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Rev. Req't. divided by 100)** | | | | **$ 2,049,762** |
| 173 | | | | | |
| 174 | **ANNUAL BASE SLICE REVENUES** | | | | **$ 556,579,261** |
| 175 | **Annual Slice Implementation Expenses** | | | | **$ 2,830,000** |
| 176 | **TOTAL ANNUAL SLICE REVENUES** | | | | **$ 559,409,261** |

# 3. COST ALLOCATION AND RATE DESIGN IMPLEMENTATION

## 3.1 Ratemaking Sequence

BPA's power ratemaking methodology includes a Cost of Service Analysis (COSA), a series of Rate Design Step adjustments, and a Slice Product Separation Step. The COSA assigns responsibility for BPA's power revenue requirement to the various classes of service in accordance with generally accepted ratemaking principles and in compliance with statutory directives governing BPA's ratemaking. The Rate Design Step adjustments to the allocated costs derived in the COSA are necessary to ensure that BPA recovers its rate period revenue requirement while following its statutory rate directives. The Slice Product Separation Step separates out the PF Slice product firm loads, allocated costs, and allocated revenue credits from the overall PF loads, allocated costs, and allocated revenue credits. This ratemaking sequence is programmed into a spreadsheet model, the Rate Analysis Model (RAM2010), for purposes of calculating BPA's requirement power rates.

## 3.2 Cost of Service Analysis

The COSA allocates the rate period power revenue requirement determined in the Revenue Requirement Study, WP-10-E-BPA-02, to BPA customer classes. The COSA first groups parts of the power revenue requirement into cost pools specified by section 7 of the Northwest Power Act. The cost pools are associated with resource pools (Federal Base System (FBS) resources, exchange resources, and new resources) and costs allocated according to section 7(g) of the Northwest Power Act. The COSA then apportions or "allocates" the cost pools among classes of service (also known as rate pools or load pools) based on the priorities of service from resource pools to rate pools provided in section 7 and the principle of cost causation when section 7 does not provide guidance. The relative use of resources, services, and facilities among customer classes is identified, and costs generally are allocated to customer classes in proportion to each class's use.

Functionalization of costs between power and transmission is performed in the development of the total generation revenue requirement, and only those costs are included in power rates. One exception to this is gross exchange resource costs, which are functionalized so that only the power portion of the exchange resource costs is subject to the power cost rate design steps, and the transmission cost portion is then added back in after the rate design steps are completed.

### 3.2.1 Power Services Revenue Requirement

The Bonneville Project Act, the Flood Control Act of 1944, the Transmission System Act, and the Northwest Power Act provide guidance regarding BPA ratemaking. The Northwest Power Act requires BPA to set rates that are sufficient to recover, in accordance with sound business principles, the costs of acquiring, conserving, and transmitting electric power, including amortization of the Federal investment in the FCRPS over a reasonable period of years, and the other costs and expenses incurred by the Administrator. 16 USC § 839e(a)(1).

The Revenue Requirement Study, WP-10-E-BPA-02, is based on power revenue and cost estimates for a two-year rate period, FY 2010-2011. A preliminary power revenue requirement from the Revenue Requirement Study is adjusted in the COSA for costs that are determined in other steps of the ratemaking process: projected balancing purchase power costs, system augmentation costs, net DSI service costs, PNRR, and the functionalized REP costs. The adjusted annual functionalized revenue requirements used for rate calculations are shown in COSA tables of the Documentation, WP-10-E-BPA-05A, Tables 2.3.1 and 2.3.2 (COSA 06 FY 2010 and COSA 06 FY 2011). The functionalization of REP costs is shown in Table 2.3.3 (COSA 07). The total adjusted functionalized revenue requirement for the two-year period is shown in Table 2.3.4 (COSA 08). The adjustments to the preliminary power revenue requirement are then incorporated into the ultimate power revenue requirement.

#### 3.2.1.1 Revenue Requirement Study

In compliance with Commission order *U.S. Department of Energy–Bonneville Power Admin.*, 26 FERC ¶ 61,096 (January 27, 1984), BPA has prepared a power repayment study specifically for the power function. All costs to be recovered through FCRPS power rates functionalized to power are used to develop the power revenue requirement in this Initial Proposal.

The Revenue Requirement Study, WP-10-E-BPA-02, also includes demonstrations to show that revenue from the proposed rates is adequate to recover all power-related costs of the FCRPS in the rate period and over the repayment period (revised revenue test).

#### 3.2.1.2 Power Purchases in the COSA

Three categories of purchased power are included in the COSA: (1) purchased power, (2) balancing power purchases, and (3) system augmentation.

##### 3.2.1.2.1 Purchased Power

The purchased power costs reflect the acquisition of power through renewable energy, wind, geothermal, and competitive acquisition programs. Costs of purchased power are included in the new resources resource pool. Documentation, WP-10-E-BPA-05A, Tables 2.3.1 and 2.3.2 (COSA 06).

##### 3.2.1.2.2 Balancing Power Purchases

The costs of power purchases and storage required to meet firm deficits on a daily and monthly basis are included in the category of balancing power purchases. Projected balancing power purchases are needed to serve firm loads in months other than the spring fish migration period under some water conditions. The cost is the expected value of balancing power purchase costs under 70 different water conditions. The expense estimate for balancing power purchases included in the preliminary power revenue requirement is adjusted in the COSA as a result of Risk Analysis Model (RiskMod) modeling to reflect projected operation of the FCRPS. Documentation, WP-10-E-BPA-05A, Section 4.8.2. Balancing power purchases are treated as FBS replacements and as such the costs are included in, and allocated as, FBS costs. Documentation, WP-10-E-BPA-05A, Tables 2.3.1 and 2.3.2 (COSA 06).

**3.2.1.2.3 System Augmentation**

BPA is also proposing to acquire an amount of resources beyond the inventory represented by the system generating resources and balancing power purchases. These acquisition amounts are determined in the Loads and Resources Study, WP-10-E-BPA-01, and are used to meet annual customer firm power loads in excess of annual firm system resources. The cost of system augmentation purchases is estimated using prices under 1937 water conditions. The expense estimate for system augmentation purchases included in the preliminary power revenue requirement is adjusted in the COSA. The adjustment is based on the application of market prices under 1937 water conditions from the 70 water year price forecast to the amount of system augmentation determined in the Loads and Resources Study. Market Price Forecast Study, WP-10-E-BPA-03, section 2.5. System augmentation purchases are treated as FBS replacements, and as such, the costs are included in and allocated as FBS costs. Documentation, WP-10-E-BPA-05A, Tables 2.3.1 and 2.3.2 (COSA 06).

Due to the timing of the *PNGC* opinion, section 2.15.3.6, for ratemaking purposes only the Initial Proposal assumes actual load service to the aluminum DSIs that was not included in the Loads and Resources Study and, therefore, additional system augmentation costs are included in the

COSA. This is treated in the COSA as augmention solely for the purpose of developing this analysis and does not reflect any decision regarding the manner, method, or level of service for the aluminum DSIs. The costs of the aluminum DSI-related system augmentation purchases use the same 1937 water condition prices used for other system augmentation purchases, and are shown separately in Column F of the COSA tables. DSI-related system augmentation purchases are treated as FBS replacements, and as such, the costs are included in and allocated as FBS costs. Total system augmentation costs are shown in the Documentation, WP-10-E-BPA-05A, Tables 2.3.1 and 2.3.2, Row 9, Column E (COSA 06 FY 2010 and COSA 06 FY 2011).

### 3.2.2 Functionalization of Residential Exchange Program Costs

In the COSA, the gross REP cost is based on participating utilities' ASCs and their exchange loads. ASCs include the cost of power and transmission services associated with serving a participating utility's total retail load. See section 6. The rate design adjustments that follow the COSA in BPA's ratemaking use the results of the COSA allocations of the power revenue requirement. Therefore, because the gross REP costs in the COSA include transmission costs, the gross REP costs are functionalized between power and transmission. The gross REP costs functionalized to power continue through the ratemaking process. The REP costs functionalized to transmission are removed from the power revenue requirement for the rate design steps and then added back to the PF Exchange rate after all of the rate design steps have been accomplished. In this way, the REP costs functionalized to power are treated the same as other power function costs through the rate design adjustment process. The functionalization of REP costs is shown in the Documentation, WP-10-E-BPA-05A, Table 2.3.3 (COSA 07).

### 3.2.3 Classification

Classification is the process of apportioning power costs among the components of electric power, usually demand, energy, and other costs. BPA discontinued traditional classification in 1996, replacing it with marginal cost-based ratemaking. As a result of this change, costs classified to demand and load variance are based on the expected revenue from marginal cost-based demand and load variance rates. These revenues are subtracted from the power revenue requirement to determine the costs classified to energy. This classification of the power revenue requirement is shown for informational purposes only in the Documentation, WP-10-E-BPA-05A, Table 2.3.4 (COSA 08). All power costs are allocated to rate pools based on energy allocation factors. See section 3.2.5.2.

In this Initial Proposal, the monthly demand rates are scaled upward from the FY 2009 demand rates, as described in section 2.4.2. The load variance rate is scaled upward from the FY 2009 load variance rate. The scaled demand and load variance rates are multiplied by forecast sales under these rates to determine expected revenues for demand and load variance. The costs classified to demand and load variance are deemed to be equal to the revenues from demand and load variance. Power costs classified to energy are the residual total power costs not classified to demand or load variance. After all allocation and rate design steps, the classification is applied by subtracting the revenues forecast to be recovered from demand and load variance rates from the overall costs allocated to each rate pool, and the energy rates collect the remainder.

### 3.2.4 Functionalized and Classified Revenue Credits

The revenue credits described below are functionalized to power. Most of these revenue credits are associated with the operation of FBS resources and have the effect of reducing the FBS resource costs to be recovered by power rates.

#### 3.2.4.1 Downstream Benefits and Pumping Power Revenues

Downstream benefits and pumping power revenues include payments from the sale of Reserve Energy and Irrigation Pumping Power. They also include revenues from owners of projects downstream to the COE and Reclamation projects for benefits received (i.e., additional generation due to releases from the storage reservoirs owned by the COE and Reclamation).

Reserve Energy and Irrigation Pumping Power revenues are earned through the year and are paid at the end of the year directly to the U.S. Treasury by the COE and Reclamation. These revenues are not subject to revision through BPA's rate process and hence become a revenue credit. Documentation, WP-10-E-BPA-05A, Table 2.3.5 (COSA 09).

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

Section 4(h)(10)(C) credits are available from the U.S. Treasury to compensate BPA for its direct program fish and wildlife expense and capital costs, and hydro system operational costs incurred for fish migration attributable to the non-power portions of the hydro projects. These credits are currently 22.3 percent of these eligible costs. This revenue credit is an estimate of the credits BPA would receive on average over a range of 70 different water conditions. The actual credit is determined after each year is completed. The operational costs vary with water conditions. Documentation, WP-10-E-BPA-05A, Table 2.3.5 (COSA 09).

#### 3.2.4.3 Colville Credit

The Colville credit is a U.S. Treasury credit BPA receives as a result of a settlement of claims associated with the development of Grand Coulee Dam. The credit is a fixed annual amount of $4,600,000 that is provided through the Confederated Tribes of the Colville Reservation Grand Coulee Dam Settlement Act, Public Law No. 103-436, adopting the settlement agreement between the Confederated Tribes of the Colville Reservation and the United States of America. The Omnibus Consolidated Rescissions and Appropriations Act of 1996, Public Law 104-134, amended section 6 of the Settlement Act to provide BPA with a credit of $4,600,000 against its annual payment to the United States Treasury for fiscal year 2002 and each succeeding fiscal year. Documentation, WP-10-E-BPA-05A, Table 2.3.5 (COSA 09).

#### 3.2.4.4 Energy Efficiency Revenues

This credit reflects revenues associated with the activities of BPA's Energy Efficiency program. These revenues are generally payments for reimbursible expenditures that are included in the power revenue requirement. The credit is allocated as an offset to BPA's conservation expenses and reduces the amount of those expenses allocated to power rates. Documentation, WP-10-E-BPA-05A, Table 2.3.6 (COSA 09A).

#### 3.2.4.5 Miscellaneous Revenues

This credit represents estimated revenues from contract administration, late fees, interest on late payments, and mitigation payments. These fees are not subject to change through BPA's rate process. Documentation, WP-10-E-BPA-05A, Table 2.3.5 (COSA 09).

#### 3.2.4.6 Reserve Product Revenues

Reserve product revenues result from the sale of products and services provided under the FPS rate schedule to customers outside the BPA BAA and may include supplemental automatic generation control, spinning reserves, supplemental reserves, and forced outage reserves. Documentation, WP-10-E-BPA-05A, Table 2.3.5 (COSA 09).

#### 3.2.4.7 Green Energy Premium Revenues

Green Energy Premiums (GEP) result from BPA's sales of Environmentally Preferred Power (EPP) and renewable energy certificates (RECs). The revenue amounts depend on actual wind and renewable project output included in the FBS. Documentation, WP-10-E-BPA-05A, Table 2.3.5 (COSA 09).

#### 3.2.4.8 Power Services Ancillary and Reserve Services Revenue Credits

Power Services, in the course of marketing power, generates transmission-related revenues and credits. The revenues and credits are predominantly revenues associated with providing reserves and energy for Ancillary Services, control area services, and other reliability needs. The Generation Inputs Study, WP-10-E-BPA-08, explains and documents these credits. These revenues have the effect of reducing the FBS resource costs to be recovered by power rates. The expected generation inputs credits are $180.452 million for FY 2010 and $215.811 million for FY 2011. Documentation, WP-10-E-BPA-05A, Table 2.3.5 (COSA 09).

#### 3.2.4.9 *Ad Hoc* Adjustment to Generation Inputs Revenue

The Initial Proposal includes a generation inputs revenue credit adjustment to account for expected changes in the cost allocation for certain generation inputs. A two-hour persistence model was assumed for determining the amount of capacity needed for generation imbalance caused by the wind generators. In order to account for other potential operational solutions, an *ad hoc* revenue credit adjustment is included that adjusts the credit to the average revenue credit associated with the 45-minute and 30-minute persistence models. Thus, the generation inputs revenue credits assumed in the rate case are offset by the downward *ad hoc* adjustment by $34.62 million per year. Documentation, WP-10-E-BPA-05A, Table 2.3.5 (COSA 09).

### 3.2.5 Allocation

Allocation is the apportionment of costs to rate pools, or customer classes. Allocation is performed by determining the relative sizes of resource pools and rate pools, pursuant to the rate directives contained in section 7 of the Northwest Power Act. The resource pools are those identified in the Northwest Power Act, specifically the FBS, exchange, and new resources resource pools. Costs associated with each of these respective resource pools are grouped together to facilitate allocation. The sizes of the rate and resource pools are determined based on the results of the Loads and Resources Study, WP-10-E-BPA-01.

Rate pools are groupings of customer classes (sales) for cost allocation purposes. The Northwest Power Act establishes three rate pools. The 7(b) rate pool includes public body, cooperative, and

Federal agency sales and sales to utilities participating in the REP established in section 5(c) of the Northwest Power Act. The 7(c) rate pool includes sales to BPA's DSI customers under contracts authorized by section 5(d). The 7(f) rate pool includes all other power BPA sells in the PNW, including sales pursuant to section 5(f). Subsequent to 1985 and implementation of the directives of section 7(c)(2) of the Northwest Power Act, BPA has had, for all practical purposes, only two rate pools: the 7(b) rate pool and all other loads.

In the Initial Proposal, the FBS resource pool consists of the costs of the following resources: (1) the FCRPS hydroelectric projects; (2) resources acquired by the Administrator under long-term contracts in force on the effective date of the Northwest Power Act; and (3) replacements for reductions in the capability of the above resource types. Costs expected to be incurred during the rate period for FBS replacement resources are included in the FBS resource pool. See sections 3.2.1.2.2 and 3.2.1.2.3.

#### 3.2.5.1 Power Cost Allocations

The process of allocating power costs begins with an examination of critical period firm loads and resources. A ratemaking load-resource balance for each year of the rate period is then constructed from the Loads and Resources Study, WP-10-E-BPA-01, and other data. From this ratemaking load-resource balance, service to each of the three rate pools from each of the resource pools is determined for the rate period. As noted above, an amount of sales under the 7(c) Industrial Firm Power rate not included in the Loads and Resources Study is assumed in this Initial Proposal for ratemaking purposes. Table 2.4.1 (ALLOCATE 01) of the Documentation, WP-10-E-BPA-05A, shows the ratemaking energy loads and resources by pools.

As shown in Table 3.1 below, allocation is based on matching service from each resource pool to each rate pool. The FBS resource pool is first used to serve the 7(b) rate pool. When the FBS resource pool is exhausted, the exchange resource pool is used to serve the 7(b) rate pool. If the combined FBS and exchange resource pools are insufficient to fully serve the 7(b) resource pool, then the new resources resource pool is used. If the exchange resource pool is not fully exhausted in serving the 7(b) rate pool, any remaining exchange resources are used to serve the "all other" rate pool; otherwise, the "all other" rate pool is served entirely from the new resources resource pool.

**Table 3.1**
**Summary of Resource Pool Service to Rate Pools**

| Resource Pool | FY 2010 7(b) Pool | FY 2010 All Other Pool | FY 2011 7(b) Pool | FY 2011 All Other Pool |
|---|---|---|---|---|
| FBS | 8,399 | | 8,399 | |
| Exchange | 3,640 | 929 | 3,720 | 901 |
| New Resources | | 108 | | 108 |
| Total Usage | 12,039 | 1,037 | 12,119 | 1,009 |

### 3.2.5.2 Energy Allocation Factors

When service from each resource pool to each rate pool has been identified, the amounts of such service are the allocation factors for the costs of the resource pool. Resource pool costs are allocated to classes of service based on the proportions of their identified use of the resource pools to the total size (use) of the resource pool. The annual energy allocation factors for each resource pool are shown in the Documentation, WP-10-E-BPA-05A, Table 2.4.1 (ALLOCATE 01). The Total Usage and the Conservation allocation factors are the same and are based on the sum of the FBS, Exchange, and New Resources allocation factors. They are used to allocate section 7(g) costs and rate design allocation adjustments to all firm energy loads. Allocated power costs are shown in the Documentation, WP-10-E-BPA-05A, Table 2.4.2 (ALLOCATE 02).

#### 3.2.5.3 Other Cost Allocations

Power costs not directly identifiable with resource pools are allocated as described in the following sections.

##### 3.2.5.3.1 Conservation Costs

The Northwest Power Act requires BPA to treat cost-effective conservation as an electric power resource in planning to meet the Administrator's obligations to serve loads. 16 USC § 839a1(a). The "conservation" line item, as seen in the COSA 06 tables (Documentation, WP-10-E-BPA-05A, Tables 2.3.1 and 2.3.2) includes: (1) debt service for BPA's previous conservation resource acquisition activities; (2) BPA's continuing contributions to the region's market transformation efforts; (3) costs associated with BPA's energy efficiency business; (4) costs associated with the Conservation Rate Credit; and (5) a share of the agency's total planned net revenues. The "Energy Efficiency" revenue line item seen in Table 2.3.6 (COSA 09A) reflects payments provided by utilities, other organizations, and Federal agencies for the energy efficiency services delivered. Energy Efficiency revenues are credited against BPA's conservation costs, and the conservation costs that are net of these revenues continue though the remaining ratemaking process. Documentation, WP-10-E-BPA-05A, Table 2.3.6 (COSA 09A). Section 7(g) of the Northwest Power Act directs that the costs of conservation be equitably allocated to power rates in accordance with generally accepted ratemaking principles. Conservation costs are allocated to all rate pools using the Conservation energy allocation factors.

##### 3.2.5.3.2 BPA Program Costs

Some of BPA's program costs are not identified directly with any specific resource pool. An example is the cost of the ratemaking process. The power portion of these program costs is determined in the Revenue Requirement Study, WP-10-E-BPA-02. The power portion appears in the COSA as BPA program costs. Section 7(g) of the Northwest Power Act directs that the costs of operating services and all costs and benefits not otherwise allocated under section 7 be equitably allocated to power rates in accordance with generally accepted ratemaking principles. BPA program costs are allocated to all rate pools based on the Total Usage energy allocation factors. Documentation, WP-10-E-BPA-05A, Table 2.3.4 (COSA 08).

**3.2.5.3.3 Planned Net Revenues for Risk (PNRR)**

PNRR is an amount of net revenues required from power rates to ensure that cash flows from proposed rates meet BPA's probability standard for repaying Power Services' portion of Treasury payments on time and in full. The PNRR value for this Initial Proposal has been determined to be $48 million per year. The amount of PNRR is the result of an iterative process between the RAM2010, RiskMod, Non-Operating Risk Model (NORM), and ToolKit models. Risk Analysis and Mitigation Study, WP-10-E-BPA-04, Section 4. The iteration is initiated with a seed value for PNRR in COSA 06 of the RAM2010. The resultant rates are used in RiskMod to produce probability distributions. These distributions are then used in the ToolKit to produce a new PNRR value for new COSA 06 tables. Documentation, WP-10-E-BPA-05A, Section 2.

The PNRR value is combined with any minimum required net revenue, and the sum of Net Revenues is found in the COSA 06 tables. Section 7(g) of the Northwest Power Act directs that the costs of the sale of or inability to sell excess electric power (a major component of PNRR) and all costs and benefits not otherwise allocated under section 7 be equitably allocated to power rates in accordance with generally accepted ratemaking principles. Net Revenues are allocated to resource pools that include Federal capital investments (FBS, Conservation, and BPA Program) using net interest cost assignment.

#### 3.2.5.3.4 Transmission Costs

Transmission costs include the costs of serving transfer service customers with Federal power provided under GTAs and other non-Federal transmission service agreements over a third-party transmission system. It also includes the costs of procuring transmission and ancillary services by Power Services to transmit surplus Federal power to purchasers outside the PNW.

Section 7(g) of the Northwest Power Act directs that the costs of operating services and all costs and benefits not otherwise allocated under section 7 be equitably allocated to power rates in accordance with generally accepted ratemaking principles. Transmission costs are allocated to all rate pools based on the Total Usage energy allocation factors. Documentation, WP-10-E-BPA-05A, Table 2.3.4 (COSA 08).

### 3.2.6 COSA Results

Table 2.4.2 (ALLOCATE 02) of the Documentation, WP-10-E-BPA-05A, summarizes the allocations of the power revenue requirement to classes of service.

## 3.3 Rate Design Step Adjustments

Rate design adjustments are performed sequentially in the order described in this section.

### 3.3.1 Secondary and Other Revenues

Secondary and Other Revenues recognizes that BPA collects revenues from certain classes of service to which costs are not allocated. BPA credits these revenues to classes of service served with firm Federal power. Projected secondary energy sales are the largest source of revenue credits.

#### 3.3.1.1 Secondary Energy Sales

For resource planning purposes and to determine the amount of system augmentation, the ratemaking process requires that the forecast of firm resources available be equal to firm load obligations under critical water conditions. However, rates are set assuming that better than critical water conditions will occur. BPA projects secondary energy sales and revenues in RiskMod using 70 historical water years. The projected secondary energy revenue credits are included so that BPA does not set power rates to recover more than its revenue requirement.

The RiskMod model is used to project the level of secondary energy sales and revenues, as discussed in the Risk Analysis and Mitigation Study, WP-10-E-BPA-04, Section 2. The FCRPS is expected to generate secondary energy that will produce about $775.1 million in revenues in FY 2010 and $904.7 million in FY 2011. Of the rate period total of $1,679.8 million in forecast secondary revenue, $368.0 million is allocated pursuant to section 7(b)(3) to the recovery of section 7(b)(2) rate protection. The remaining $1,311.8 million is allocated as a revenue credit. Section 7(g) of the Northwest Power Act directs that all benefits from the sale of excess electric power not otherwise allocated under section 7 be equitably allocated to power rates in accordance with generally accepted ratemaking principles. Secondary energy revenues remaining after the allocation pursuant to section 7(b)(3) are allocated to rate pools based on the FBS energy allocation factors. Documentation, WP-10-E-BPA-05A, Table 2.5.3 (RDS 11). In one of the last ratemaking steps, the Slice Separation Step, 22.63 percent of the $1,679.8 million in forecast secondary revenue for the rate period, or about $380.1 million, will be sold to BPA's Slice product customers, reducing the revenue credit allocated to the PF Preference rate. Documentation, WP-10-E-BPA-05A, Table 2.6.1 (SLICESEP 01).

#### 3.3.1.2 Other Revenue Credits

BPA receives revenue from miscellaneous sources and from miscellaneous power sales. These revenue credits are allocated as described in section 3.2.4. For FY 2010, the forecast revenue from these sources is $258.4 million, and for FY 2011, $295.1 million. Documentation, WP-10-E-BPA-05A, Table 2.5.3 (RDS 11).

### 3.3.2 Firm Power Revenue Deficiencies Adjustment

BPA sells firm power at contractual rates and in the open market under the FPS rate schedule. The COSA includes these sales in the 7(f) rate pool and allocates costs to these sales. Sales of such firm power are not necessarily made at the fully allocated cost of the power. Therefore, either a revenue surplus or a revenue deficiency will result when a comparison is made between the costs allocated to the sales of this firm power and the revenues received from the sale of such power. In the FY 2010-2011 rate period, revenue of $263.5 million is forecast from the sale of firm power in various PNW and Southwest markets. Documentation, WP-10-E-BPA-05A, Table 2.5.4 (RDS 17). The initial proposal allocates $624.9 million in power costs to this firm power. Therefore, there is a revenue deficiency of $361.4 billion over the two-year rate period. This revenue deficiency is allocated to all other firm power (PF, IP, and NR) rates. Documentation, WP-10-E-BPA-05A, Table 2.5.4 (RDS 17).

### 3.3.3 Rate Discount Costs

Section 7(d) allows BPA to apply discounts to the rates of customers with low system densities. See section 2.10. In addition, BPA offers the IRMP to allow discounted power sales for irrigation loads. See section 2.9. The revenues collected through PF Preference rate sales after these discounts are applied will be lower than allocated to the PF Preference class of service. Therefore, an estimate of the revenue discounts is added to the costs allocated to the PF class of service. Documentation, WP-10-E-BPA-05A, Table 2.5.5 (RDS 19). The costs of the CRC are already included in the power revenue requirement, so no further adjustment is necessary.

### 3.3.4 7(c)(2) Adjustment

DSI ratesetting is based on sections 7(c)(1), 7(c)(2), and 7(c)(3) of the Northwest Power Act. Section 7(c)(1)(B) provides that, after July 1, 1985, the rates to DSI customers will be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." Pursuant to section 7(c)(2), the IP rate is to be based on BPA's "applicable wholesale rates" to its COU customers plus the "typical margins" included by those customers in their retail industrial rates. Section 7(c)(3) provides that the IP rate is to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. This adjustment is typically made through a Value of Reserves (VOR) credit. Thus, the IP rate is set equal to the applicable wholesale rate, plus the typical margin, minus the VOR credit, subject to the DSI floor rate test and the outcome of the section 7(b)(2) rate test. See sections 3.3.4 and 3.3.5 below for additional explanation.

The applicable wholesale rate is the weighted average of (1) the PF rate and (2) the NR rate sales to COU NLSLs (none are projected for the rate period) at the DSI load factor. The typical margin is based generally on the overhead costs that COUs add to BPA's price of power in setting their retail industrial rates. The typical margin is 0.573 mills/kWh and has not been changed from the WP-07 Final Proposal. A VOR credit to the IP rate of 0.005 mills/kWh has been calculated as one-half of the VOR provided by the DSIs shown in section 2.2.1. The typical margin minus the VOR credit yields the net margin of 0.568 mills/kWh. The net margin is added to the monthly diurnal PF energy rates. These adjusted energy rates and the demand rates are applied to the DSI rate period billing determinants to determine the initial IP rate.

The 7(c)(2) adjustment is necessary to account for the difference between the revenues BPA expects to recover from the DSIs at the initial IP rate and the costs allocated to the DSIs. This difference, known as the 7(c)(2) delta, is allocated to non-DSI customers, primarily the PF customers. However, the allocation of this 7(c)(2) delta then changes the PF rate, the rate upon which the IP rate is based, and the 7(c)(2) delta must be recalculated. The interaction between the PF rate and the IP rate has been reduced to an algebraic solution. Documentation, WP-10-E-BPA-05A, Table 2.5.6 (RDS 21).

### 3.3.5 7(b)(2) Adjustment

The rate test specified in section 7(b)(2) of the Northwest Power Act ensures that BPA's public body, cooperative, and Federal agency customers' firm power rates applied to their requirements loads are no higher than rates calculated using specific assumptions that remove certain effects of the Northwest Power Act. Section 7(b)(2) Rate Test Study, WP-10-E-BPA-06. If the 7(b)(2) rate test triggers, the public body, cooperative, and Federal agency customers are entitled to rate protection. The cost of this rate protection is borne by all other BPA sales, pursuant to section 7(b)(3). Some PF customers receive rate protection, while other PF customers pay a portion of the cost of the rate protection. Thus, to allow the cost reallocations due to the rate protection, the PF rate is bifurcated. The two resulting rates are the PF Preference rate, which receives the rate protection, and the PF Exchange rate, which does not receive rate protection and bears its allocated share of the rate protection reallocation. The rate protection amount is collected though section 7(b)(3) Supplemental Rate Charges applied to all non-PF Preference sales. A further calculation is performed to determine utility-specific 7(b)(3) Supplemental Rate Charges for utilities participating in the Residential Exchange Program. Documentation, WP-10-E-BPA-05A, Table 2.9 (REP 1).

The Section 7(b)(2) Rate Test Study, WP-10-E-BPA-06, indicates that the 7(b)(2) rate test has triggered, and thus the PF rate applicable to BPA's COU customers, the PF Preference rate, should be adjusted downward. Subsequent to the section 7(b)(2) rate test, three adjustments in the rate design steps sequence provide this rate protection to COU customers and reallocate the rate protection.

First, the PF Preference customer class is allocated a credit, which reduces its rate, by the amount of the protection indicated in the Section 7(b)(2) Rate Test Study, WP-10-E-BPA-06. In the Initial Proposal, the rate protection amounts to 8.07 mills/kWh, for a rate period reduction of about $1,029.2 million to the allocated costs for the PF Preference customer class. This protection is reallocated to all other sales. Documentation, WP-10-E-BPA-05A, Table 2.5.9 (RDS 30).

### 3.3.6 7(b)(2) Industrial Adjustment

The second adjustment is the 7(b)(2) Industrial Adjustment. The amount of this adjustment is the value of a recalculated 7(c)(2) delta at the lower PF Preference rate that resulted from the allocation of the 7(b)(2) rate protection to the PF Preference rate. The same adjustments described in the 7(c)(2) Adjustment, section 3.3.4, are performed again with the lower PF Preference rate. Documentation, WP-10-E-BPA-05A, Table 2.5.10 (RDS 33).

### 3.3.7 REP Deemer Adjustment

If in this Initial Proposal it had been forecast that an exchanging utility was in deemer status, a third adjustment would have been necessary to allocate an increase in the gross Residential Exchange costs resulting from the increase of the PF Exchange rate, which results from the reallocation of the 7(b)(2) rate protection. A utility in deemer status has an ASC lower than the PF Exchange rate. To eliminate the necessity for such an exchanging utility to pay BPA money, its ASC is deemed equal to the PF Exchange rate. Gross exchange costs up to this point are calculated prior to the 7(b)(2) rate test using a lower PF Exchange rate for its ASC. Now, with the higher PF Exchange rate, the utility's ASC is higher than before the reallocation of the rate protection. Therefore, gross exchange costs must be recalculated. Any increase in the gross exchange costs can be allocated only to the PF Exchange rate and the NR rate. Because no exchanging utility is forecast to be in deemer status, this rate adjustment is not necessary.

### 3.3.8 DSI Floor Rate Test

Section 7(c)(2) of the Northwest Power Act requires that the rates to DSI customers shall not be less than the rates in effect for the contract year ending June 30, 1985. Accordingly, a test is performed to determine if the proposed IP rate is at a level below the 1985 IP rate (the floor rate).

If so, an adjustment is made that raises the IP rate to the floor rate and credits other customers with the increased revenue from the DSIs. If the proposed IP rate has been set at a level above the floor rate, no floor rate adjustment is necessary.

The first step in calculating the floor rate is to apply the IP-83 Standard rate components to rate period (FY 2010 and FY 2011) DSI billing determinants. The resulting revenue figure is divided by total IP rate period energy loads to arrive at an average rate in mills/kWh. This rate is reduced by an Exchange Cost Adjustment and a Deferral Adjustment that were included in the IP-83 rate but are no longer applicable. Both adjustments are made on a mills/kWh basis.

In addition, the transmission component of the IP-83 rate is removed to allow a power-only floor rate comparison. The floor rate is adjusted for transmission costs by subtracting total transmission costs in mills/kWh from the IP-83 rate in the same manner that the Exchange Cost Adjustment and Deferral Adjustment are removed. The mills/kWh component was determined by dividing total transmission costs in the IP-83 rate by the total energy billing determinants for that rate period. The transmission cost adjustment amounts to 3.81 mills/kWh.

These calculations result in an undelivered DSI floor rate of 20.96 mills/kWh. The floor rate is applied to the rate period DSI billing determinants to determine floor rate revenue. Revenue at the proposed IP rates is compared to revenue at the floor rate. Because the proposed IP rate revenue is greater than the floor rate revenue, no floor rate adjustment is necessary to the proposed IP rate. Documentation, WP-10-E-BPA-05A, Tables 2.5.7 (RDS 23) and 2.5.8 (RDS 24), for the DSI floor rate calculation. With no DSI floor adjustment required, the final Rate Design Step cost allocations are shown in the Documentation, Table 2.5.10 (RDS 33).

### 3.4 Slice Cost Calculation

Slice customers assume the obligation to pay a percentage of BPA's costs, rather than a predetermined rate per kilowatt or kilowatthour. See section 2.15. A Slice customer's obligation to pay is equal to the percentage of the FCRPS that the Slice customer elects to purchase. The costs considered by the Slice contract are referred to collectively as the Slice Revenue Requirement. The Slice Revenue Requirement is comprised of all of the line items in the power revenue requirement identified in this Initial Proposal, with certain limited exceptions. The calculation of the cost of the Slice product for FY 2010 and FY 2011 in dollars per month for each percent of the Federal system is shown in the Documentation, WP-10-E-BPA-05A, Table 2.13 (Slice Cost Table).

### 3.5 Slice PF Product Separation Step

After the COSA and Rate Design steps, costs allocated to the 7(b) rate pool have been bifurcated to the PF Preference class of service (all firm PF Preference load) and PF Exchange class of service. The Slice Separation Step separates out the PF Slice product revenues, firm loads, and revenue credits from those allocated to the entire PF Preference class of service, leaving the costs that must be recovered from the remaining non-Slice PF Preference load through the PF Preference energy, demand, and load variance rates. Documentation, WP-10-E-BPA-05A, Table 2.6.1 (SLICESEP 01).

#### 3.5.1 7(c)(2) Non-Slice PF Adjustment

After the Slice PF Product Separation Step, the PF Preference rate level may have changed, necessitating a third 7(c)(2) adjustment. This final rate adjustment sets the final IP rate equal to the non-Slice PF rate at the DSI load factor, plus the net industrial margin, plus any 7(b)(3) Supplemental Rate Charge. Documentation, WP-10-E-BPA-05A, Table 2.6.2 (SLICESEP 02).

### 3.6 Rate Analysis Results

The rate modeling described above results in an average PF-10 Preference rate of 29.43 mills/kWh, an average IP-10 rate of 36.37 mills/kWh, an average NR-10 rate of 69.72 mills/kWh, and a load-weighted average PF Exchange rate of 49.44 mills/kWh. Documentation, WP-10-E-BPA-05A, Tables 2.7, 2.10, 2.11, and 2.9A. The rate modeling produces the actual component rates of the PF-10, IP-10, and NR-10 rate schedules, found in WP-10-E-BPA-07.

# 4. REVENUE AND PURCHASE POWER EXPENSE FORECAST

This section describes the revenue forecast and purchase power expenses prepared for the WP-10 Initial Proposal and presents the results of that forecast for FY 2009, FY 2010, and FY 2011.

## 4.1 Overview

The revenue forecast presents the expected level of sales and revenue from power rates and other sources for the rate period, FY 2010-2011. Two revenue forecasts are prepared. One uses current rates, and the other uses proposed rates. These forecasts are used to test whether current rates will cover the power revenue requirement and whether proposed rates are sufficient to recover the revenue requirement. The revenue test is described in the Revenue Requirement Study, WP-10-E-BPA-02, section 4.1.1. The power rates placed in effect October 1, 2008, are used in the calculation of revenue at current rates for FY 2010-2011 and using the load forecast in the Loads and Resources Study, WP-10-E-BPA-01.

The proposed rates also are applied to the same loads to create a revenue forecast at proposed rates for FY 2010-2011. The revenue from this forecast is shown in the Documentation, WP-10-E-BPA-05A, Table 4.6.2.

## 4.2 Revenue Forecast Methodology

The first step in developing the revenue forecast is to apply rates to the forecast of firm sales. For long-term contracts, because they contain confidential information, the revenues calculated for individual contracts are summed and added to the forecast as a group. The sales forecast to be made under regional pre-Subscription FPS contracts are multiplied by the specific contract rates. Because these contracts contain confidential information, the billing determinants and revenues are totaled. The revenues are reported for HLH energy, LLH energy, demand, and load variance.  Some of these contracts have only HLH and LLH energy billing determinants and one, Canadian Entitlement Return, represents an obligation for which no revenue is received. Documentation, WP-10-E-BPA-05A,Tables 4.6.1 and 4.6.2.

Subscription power sales billing determinants from the sales forecasts are applied to the appropriate set of PF or IP rates to calculate BPA's expected revenue from these contracts. Revenues from long-term contract sales are calculated by applying the contract rates to these contracts in the same manner as the revenues are calculated from pre-Subscription contracts. These contracts also contain confidential information; therefore, the contract revenues are summed and displayed grouped.  Generation inputs for ancillary services and other services and inter-business line cost allocations are added to the power revenues.

### 4.2.1 Other Factors Affecting Forecast Revenues

Other factors affecting forecast revenues include the LDD and Irrigation Rate Mitigation sales, which are described below.

## 4.3 Power Sales Forecast

The proposed sales forecast used in the revenue forecast is the source of energy and demand billing determinants used to calculate rates and revenues.  The energy load forecasts include forecast energy loads of PF, IP, NR and FPS sales.  In the Initial Proposal, no sales are forecast at the NR rate, and due to the timing of the *PNGC* opinion, IP rate sales are not fully incorporated into the revenue forecast.  The energy load forecasts used in this rate proposal are documented in the Loads and Resources Study, WP-10-E-BPA-01, and accompanying Documentation, WP-10-E-BPA-01A.

The firm loads under Subscription contracts expected using current rates are the same as the firm loads expected using proposed rates.  Because the same load forecast is used for both revenue forecasts, the forecasts of surplus market and other sales are also the same. The only revenues that differ between these forecasts are for PF and IP rate sales. Documentation, WP-10-E-BPA-05A, Tables 4.6.1 and 4.6.2.

### 4.4 Power Revenue Forecast

Power Services' revenue comes from five sources. The first (and largest) source of revenue is the sale of firm power under Subscription (including Slice) contracts to regional public and Federal agencies.

The second revenue source is long-term contractual obligations, where the prices are already determined by contract or by contract formula.

The third source of revenue is short-term energy sales, where prices are determined by the market. This source includes power sold on a monthly, weekly, daily, or hourly basis. Bookouts are a common practice in the utility industry to minimize transmission expenses when deliveries of two transactions of equal size moving in opposite directions of a transmission line are cancelled out by the transacting parties. Since FY 2004, bookouts have been required by GAAP to be subtracted from both revenue and expenses, but the dollars still change hands as if the transaction occurred. In FY 2009, bookouts through December are -$14 million. Documentation, WP-10-E-BPA-05A, Table 4.6.1, line 17.

The fourth source of revenue is the sale of generation inputs to Transmission Services. The majority of this revenue comes from the sale of generation inputs to Transmission Services. See section 3.2.4.8.

The last revenue source is revenue credits from the U.S. Treasury and revenues from miscellaneous sources, such as payment for energy efficiency installations, storage fees, contract administration, contract termination and settlement fees, low-voltage delivery charges, reimbursement of transfer fees, and interest on late payments. The credits include those associated with Northwest Power Act section 4(h)(10)(C) and the Colville Settlement. The credit associated with BPA payments to the Colville Tribe for the use of reservation land for power production is fixed by statute. See section 3.2.4.3.

### 4.4.1 Forecast of Subscription Revenues for FY 2010 and 2011

The Subscription contracts currently in effect describe the basic products for which the Initial Proposal rates are designed. Most of BPA's firm power will be sold under these contracts. The revenue from these contracts is estimated by applying the current and proposed rates to the projected billing determinants. The LDD also is applied to eligible loads. The Conservation Rate Credit (CRC) included in the rate schedules is reflected in Power Services' expenses rather than in the revenues. Current rates applied to these sales yield revenue of $1,764 million for FY 2010 and $1,781 million for FY 2011. Documentation, WP-10-E-BPA-05A, Table 4.6.1, lines 4 and 5. Proposed rates applied to these sales yield revenue of $1,943 million for FY 2010 and $1,962 million for FY 2011. Documentation, WP-10-E-BPA-05A, Table 4.6.2, lines 4 and 5.

#### 4.4.1.1 Low Density Discount (LDD)

Section 7(d)(1) of the Northwest Power Act provides that, in order to avoid adverse impacts on retail rates of BPA's purchasers with low system densities, BPA shall apply, to the extent appropriate, discounts to the rate or rates for such purchasers. See section 2.10. The calculation of the LDD for a representative but unidentified customer is shown in Table 4.10 of the Documentation, WP-10-E-BPA-05A. The calculation is compared to the output from the Revenue Forecast Application (RFA) database to demonstrate how the LDD calculations are performed.

#### 4.4.1.2 Irrigation Rate Mitigation Sales

The Irrigation Rate Mitigation Product provides sales to irrigation loads that total 196 aMW for each of FY 2009, 2010, and 2011. Documentation, WP-10-E-BPA-05A, Table 4.6.1, line 7. The revenue from these Irrigation Rate Mitigation sales is based on contractually specified FPS rates that are lower than the PF rate but change by the amount of the base PF rate change.

### 4.4.2 Contract Formula Rates

Some of BPA's contracts include specified formulas for calculating rates. These rates are based on a variety of factors, including changes in the PF rate and changes in the BPA Average System Cost (BASC). Contracts that could be in either the sale or power exchange mode are assumed to be in the exchange mode for FY 2010 through FY 2011, or until the contracts expire. Revenue from Power Services' in-region and out-of-region long-term contract sales is forecast to total $166 million for FY 2010 and $154 million for FY 2011. Documentation, WP-10-E-BPA-05A, Table 4.6.1, lines 6, 7, 10, and 15.

### 4.4.3 Short-Term Market Sales

The revenue forecast includes revenues from the sales of surplus energy, which is energy in excess of that required to serve firm loads. For rate development purposes, the forecast of firm FCRPS output is based upon critical (1937) water conditions. FCRPS output, while uncertain, is expected to be greater than under 1937 water conditions. The surplus energy revenue included in the revenue forecast is the average of the surplus energy revenues computed for each of 70 historical water years. This power is sold under the FPS rate schedule.

Short-term market sales are computed using RiskMod to calculate monthly HLH and LLH energy surpluses for each of the 70 water years and applies corresponding market prices for each water condition. Risk Analysis and Mitigation Study, WP-10-E-BPA-04, Section 2.1.

The results of the 70 water year run of RiskMod and the resulting short-term market sales and corresponding revenues are average $600 million for FY 2010 and $700 million for FY 2011. Documentation, WP-10-E-BPA-05A, Table 4.8.1.

**4.4.4 Section (4)(h)(10)(C) Credits and Colville Settlement**

RiskMod also produces the average annual section 4(h)(10)(C) operational credits that BPA can claim when making its annual U.S. Treasury payments. Risk Analysis and Mitigation Study, WP-10-E-BPA-05, Section 4, and Documentation, WP-10-E-BPA-05A, Summary Table 4.6.1, line 12. These average annual values are derived by estimating the amount of section 4(h)(10)(C) operational credits that BPA could claim under each of the 70 historical streamflow conditions and then adding them to the other 4(h)(10)(C) credits BPA will receive. Risk Analysis and Mitigation Study, WP-10-E-BPA-05, Section 4, and Documentation, WP-10-E-BPA-05A, Summary Table 4.6.1, line 12.

The additional purchased power costs of the fish and wildlife recovery programs are determined by comparing purchased power expenses associated with FCRPS operations before any restrictions were placed on river operations with FCRPS operations for fish mitigation. The Risk Analysis and Mitigation Study uses the generation that could have been achieved without the current restrictions as a baseline. The critical period Firm Energy Load Carrying Capability (FELCC), before changes for fish and wildlife operations, is used as the base firm energy load for this forecast. The cost of the increased purchases is estimated using RiskMod and the Market Price Forecast. Risk Analysis and Mitigation Study, WP-10-E-BPA-05, Section 4, and Documentation, WP-10-E-BPA-05A, Summary Table 4.6.1, line 12.

A portion of the increased purchased power expenses (22.3 percent) is included in the section 4(h)(10)(C) credit. Documentation, WP-10-E-BPA-05A, Table 4.5. The FCRPS is a multi-purpose river system used for a number of purposes in addition to power production. The

22.3 percent of the increased purchased power expenses represents the non-power portion of the total FCRPS costs. BPA incurs or pays the entire additional power costs and is reimbursed by Treasury for the non-power share of those costs. The total section 4(h)(10)(C) credit is forecast to be $89 million for FY 2010 and $90 million for FY 2011. Documentation, WP-10-E-BPA-05A, Table 4.6.2, line 12. The section 4(h)(10)(C) credit calculations are shown in the Documentation, WP-10-E-BPA-05A, Table 4.5. The Treasury credit for the Colville Settlement in FY 2010 and FY 2011 is set by legislation at $4.6 million per year [Public Law No. 103-436; 108 Stat. 4577, as amended].

#### 4.4.5 Revenue from the Sale of Generation Inputs and Other Services

Revenue from generation inputs sold to Transmission Services includes Regulating Reserves, Wind Balancing Reserves, and Operating Reserves. Revenue from generation inputs for other services sold by Transmission Services that contain a generation component includes Synchronous Condensing, Generation Dropping, and Imbalance Energy. Other inter-business line revenues include Redispatch, Segmentation of COE and Reclamation network and delivery facilities costs, and station service. All these generation inputs are discussed in the Generation Inputs Study, WP-10-E-BPA-08.

In FY 2009, revenue from generation inputs and other services is expected to total $80 million, which includes $3 million in revenue received from sales of reserve services. Revenue from the sale of generation inputs at current rates is expected to be $155 million for FY 2010 and $155 million for FY 2011. Documentation, WP-10-E-BPA-05A, Table 4.6.1, line 11. For proposed rates, revenue from the sale of generation inputs is expected to be $180 million for FY 2010 and $216 million for FY 2011. Documentation, WP-10-E-BPA-05A, Table 4.6.2, line 11. There is no explicit forecast of reserve services for FY 2010 and FY 2011. Starting in FY 2010, revenue from the sale of reserve services is incorporated with net secondary revenue. Generation Inputs Study, WP-10-E-BPA-08, section 1. The revenue forecast at current rates from the sale of generation inputs for Wind Integration - Within-Hour Balancing Service is $17 million for FY 2009, $98 million for FY 2010, and $98 million for FY 2011. For proposed rates, the revenue forecast from the sale of generation inputs for Wind Integration - Within-Hour Balancing Service is $104 million for FY 2010 and $140 million for FY 2011. Generation Inputs Study, WP-10-E-BPA-08, Section 1, Table 1.1. In addition, an downward adjustment to the wind integration credits of $34.6 million for both FY 2010 and FY 2011 is included to account for expected changes in allocating costs to wind balancing services. See section 3.2.4.9.

#### 4.4.6 Slice True-Up

The Slice True-Up Adjustment Charge forecast for FY 2010 is $5,660,000, which represents a charge to Slice customers. Documentation, WP-10-E-BPA-05A, Table 4.6.1, line 8. The forecast for FY 2011 is $0. See section 2.15.6.

#### 4.4.7 Energy Efficiency

BPA projects revenues of $23.9 million per year for FY 2010 through FY 2011 from reimbursement for energy efficiency installations. Documentation, WP-10-E-BPA-05A, Table 4.6.1, line 12. Energy efficiency revenues are documented in the budget estimates prepared in FY 2009. Documentation, WP-10-E-BPA-05A, Table 4.9.

### 4.5 Power Purchase Expense Forecast

#### 4.5.1 System Augmentation Purchase Expense

As explained in section 4.3.3, the forecast of firm FCRPS output is based upon critical (1937) water conditions. The forecast annual firm FCRPS output plus other Federal resources is not adequate to meet annual average firm loads. Therefore, system augmentation is added to Federal resources to balance firm annual resources with firm annual loads. The Loads and Resources Study projects the aggregate need to acquire 382 aMW of system augmentation to meet firm loads in FY 2010 and 607 aMW in FY 2011. Load and Resources Study, WP-10-E-BPA-01,

Table 2.2. Forecast costs of this system augmentation are $177 million in FY 2010 and $305 million in FY 2011. Documentation, WP-10-E-BPA-05A, Table 4.6.1, line 22.

BPA has contracted with certain Slice customers to purchase ERE of 10 aMW in FY 2010 and 8 aMW in FY 2011. Loads and Resources Study, WP-10-E-BPA-01. section 2.3.4; Documentation, WP-10-E-BPA-05A, Table 4.8.3. The ERE amounts are deducted from the aggregate augmentation amounts to determine the augmentation amount used in this study. The expense for the remaining augmentation amounts, 372 aMW in FY 2010 and 599 aMW in FY 2011, is based on projected prices using the AURORA$^{xmp®}$ model assuming critical water conditions. Risk Analysis and Mitigation Study Documentation, WP-10-E-BPA-04A, section 1.4. These prices, which are computed as monthly weighted average prices, and the corresponding cost of these augmentation purchases are documented in WP-10-E-BPA-05A, Table 4.8.3, and can also be found in Summary Table 4.6.1, line 22.

#### 4.5.2 Short-Term Market Purchases

The revenue forecast includes expenses from balancing power purchases, which is additional energy required to serve firm loads. While system augmentation results in a balance of firm loads and firm resources on an annual basis, Federal resources may not be adequate to serve all firm loads at all times during a year.

Short-term balancing power purchases are calculated by RiskMod finding any monthly HLH and LLH energy deficits under each of the 70 water years and applying the corresponding market prices for each water condition.

The results of the 70 water year run of RiskMod and the resulting balancing purchases are forecast to total $66 million for FY 2010 and $53 million for FY 2011. Documentation, WP-10-E-BPA-05A, Table 4.8.2.

## 4.6 FY 2010 and FY 2011 Revenue

The forecasts of revenue using current rates for FY 2010 and FY 2011 are projected to total $2,784 million for FY 2010 and $2,885 million for FY 2011, excluding bookouts. Documentation, WP-10-E-BPA-05A, Table 4.6.1. Revenue from firm power sales to public utilities and Federal customers at the PF-07R and FPS-07R rates is projected to total $1,828 million in FY 2010 and $1,836 million in FY 2011. *Id.*, lines 10 and 15. This amount excludes the return of Lookback Amounts.

Total revenue under proposed rates is projected to be $2,994 million for FY 2010 and $3,132 million for FY 2011. Documentation, WP-10-E-BPA-05A, Table 4.6.2.

Long-term surplus contract revenues, including sales at PPL-90, WNP-3 Exchange rate, COE and Reclamation reserve energy and Irrigation Pumping Power rates, and other contracts that are determined by prior contractual arrangements are projected to be $108 million in FY 2010 and $99 million in FY 2011. Documentation, WP-10-E-BPA-05A, Table 4.6.1, lines 10 and 15.

Revenue from the sale of generation inputs is projected to be $155 million in FY 2010 and $155 million for FY 2011. *Id.*, line 11.

Revenue from section 4(h)(10)(C) credits is projected to be $89 million in FY 2010 and $90 million in FY 2011. Documentation, WP-10-E-BPA-05A, Table 4.5, and Table 4.6.1, line 12. Revenue credited to BPA associated with the Colville Settlement is $4.6 million for both FY 2010 and FY 2011.

Miscellaneous revenues from the Energy Service activities, Renewable Energy Certificates, Green Energy Premiums, and other sources are projected to total $31 million in FY 2010 and $31 million in FY 2011.  Documentation, WP-10-E-BPA-05A, Table 4.6.1, line 14.

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## 5. RATE SCHEDULE DESCRIPTIONS

The wholesale power rates and GRSPs described in this section are presented in their entirety in a separate document, WP-10-E-BPA-07.

Each rate schedule describes the customers for whom the rate schedule is available, the date the rate schedule is effective, the proposed rates for the products offered under the schedule, the associated billing factors, and references to sections of the GRSPs that apply to that rate schedule. The rate schedules also contain appropriate transmission purchasing policies and charges for power customers. The transfer services rates include the GTA-10 GTA Delivery Charge and Transfer Service Operating Reserve Charge, described in section 2.14.

The GRSPs describe the adjustments, charges, and special rate provisions applicable to the various rate schedules. The GRSPs also define the power products and services BPA offers, describe the rate schedules, and define other applicable terms. Appendix A to the rate schedule and GRSP document contains the Slice Rate Methodology. Appendix B contains the Customer Lookback Credit for the Residential Exchange Program.

### 5.1 Priority Firm Power Rate, PF-10

The proposed PF-10 rate schedule replaces the PF-07R rate schedule and is applicable for the rate period, FY 2010-2011. The PF-10 rate schedule is available for the purchase of power by eligible consumer-owned utilities, Federal agencies, and utilities participating in the Residential Exchange Program under section 5(c) of the Northwest Power Act. PF power must be used to meet the purchasers’ firm loads within the Pacific Northwest.

The PF-10 rate schedule includes two sections, one applicable to purchasers under the 2002 Subscription contracts (PF Preference rate) and the other applicable for eligible customers that have signed Residential Purchase and Sale Agreements (PF Exchange rate). The PF Preference rate is available to meet the general requirements of consumer-owned utilities and Federal agencies. At BPA's discretion, and subject to specified limitations, BPA also may make available the Flexible PF Rate Option, which includes rates and billing factors as mutually agreed upon by BPA and the Purchaser.

The PF-10 Demand rate is monthly differentiated. The PF-10 Preference Energy rates are monthly and diurnally differentiated. The PF Exchange rate, in contrast, is proposed to be a single annual Energy rate subject to a 7(b)(3) Supplemental Rate Charge established specifically for each respective utility.

Most purchases under the PF-10 rate schedule are subject to certain provisions of the GRSPs, including, among others, the Conservation Rate Credit (CRC), Cost Recovery Adjustment Clause (CRAC), Dividend Distribution Clause (DDC), NFB Mechanisms, Targeted Adjustment Charge (TAC), Low Density Discount (LDD), and Unauthorized Increase Charge (UAI Charge). If customers choose to purchase the PF Partial Service Complex Product, they can be subject to the Excess Factoring Charge. Purchases under the PF-10 rate schedule are subject to the BPA billing process.

### 5.2 New Resource Firm Power Rate (NR-10)

The NR-10 rate schedule is available for purchase of power by investor-owned utilities under net requirements contracts for resale to consumers and to consumer-owned utilities for New Large Single Loads (NLSLs).

NR-10 rates are proposed for Demand, Energy, and Load Variance. At BPA's discretion, and subject to specified limitations, BPA also may make available the Flexible NR Rate Option, which includes rates and billing factors as mutually agreed to by BPA and the purchaser, as limited by the GRSPs. The NR-10 rate includes a monthly differentiated Demand rate and monthly and diurnally differentiated Energy rates. The Energy rate is subject to a 7(b)(3) Supplemental Rate Charge. Purchases under the NR-10 rate schedule are subject to certain provisions of the GRSPs, including the CRAC, the NFB Mechanisms, the DDC, the CRC, the LDD, the UAI Charge, and for some products, the Excess Factoring Charge. Purchases under the NR-10 rate schedule are subject to the BPA billing process.

### 5.3 Industrial Firm Power Rate (IP-07R)

The IP-10 rate schedule is available to BPA's direct-service industrial customers (DSIs) for firm take-or-pay block power to be used in their Pacific Northwest industrial operations.

The IP-10 rate schedule includes a monthly differentiated Demand rate and monthly and diurnally differentiated Energy rates. Energy rates are subject to a 7(b)(3) Supplemental Rate Charge. Purchases under the IP-10 rate schedule are subject to provisions of the GRSPs, as listed in the rate schedule, including the Operating Reserves (Supplemental) Adjustment, the CRAC, the NFB Mechanisms, the DDC, and the UAI Charge.

### 5.4 Firm Power Products and Services Rate (FPS-10)

The FPS-10 rate schedule is available for purchase of Firm Power, Capacity, Capacity without Energy, Supplemental Control Area Services, Shaping Services, Reservation and Rights to Change Services, and Reassignment or Remarketing of Surplus Transmission Capacity inside and outside the Pacific Northwest. The FPS-10 contains a Flexible rate. The Flexible rate is a negotiable, market-based rate. The Flexible rate may have a Demand component, an Energy component, or both, and is subject to a 7(b)(3) Supplemental Rate Charge. Unbundled products also are available under the FPS-10 rate schedule at flexible rates as mutually agreed by the contracting parties. Applicable transmission rates will apply, to the extent required, to purchases of firm power under the FPS-10 rate. Purchases under the FPS-10 rate schedule also are subject to the BPA billing process.

# 6. AVERAGE SYSTEM COST FOR THE RESIDENTIAL EXCHANGE PROGRAM

## 6.1 Overview of Average System Cost and Residential Exchange Program

This section describes BPA's process for estimating the Average System Cost (ASC) of resources used to produce electricity sold by utilities participating in the Residential Exchange Program (REP) for FY 2010-2011.

Under the REP, BPA offers to purchase power from each participating utility at that utility's ASC. The Administrator then offers, in exchange, to sell an equivalent amount of electric power to the utility at BPA's PF Exchange rate. The amount of power purchased and sold is equal to the qualifying residential and small farm load of each utility participating in the REP. The monetary benefits of this "exchange" must be passed on to the residential and small farm customers of the utility.

Utility ASCs are not determined in BPA rate proceedings. Instead, ASCs are determined in a separate administrative process (the ASC Review Process) that BPA conducts pursuant to the procedural rules of the 2008 ASC Methodology (ASCM), which was granted interim approval by the Commission on September 30, 2008. ASCM at II.B.2.

Utility ASCs, once established in the ASC Review Process, are one component used in the WP-10 rate development process to forecast the REP costs that must be collected in rates for the rate period.

For clarity and context in this rate proposal, certain components of the ASC determination are described for the rate period, FY 2010-2011. Background information, publications, procedures and review schedules, participating utilities' data and ASC filings, and BPA's published reports are located at [http://www.bpa.gov/corporate/finance/ascm/](http://www.bpa.gov/corporate/finance/ascm/).

### 6.2 ASC Determination

A utility interested in participating in the REP is required to submit cost and load data to BPA for an ASC determination through the formal ASC Review Process. The quotient resulting from dividing a utility's ASC Contract System Cost by the utility's ASC Contract System Load is the utility's ASC.

The ASC Contract System Cost is the sum of the utility's allowable production- and transmission-related costs. The ASC Contract System Load is the sum of the total retail load of a utility, as measured at the meter, plus distribution losses, less any New Large Single Loads (NLSL). BPA establishes a utility's Contract System Cost and Contract System Load pursuant to the 2008 ASCM in consultation with regional parties. A summary of the total retail loads is shown in the Loads and Resources Study Documentation, WP-10-E-BPA-01A, Table 2.2.7. Distribution losses are calculated using the distribution loss factor contained in the utilities' ASC submittals to BPA. In addition, as part of their ASC submittals, the utilities include any NLSLs they are currently serving or are projected to serve during the ASC Exchange Period (FY 2010-2011). No utilities identified any new NLSLs for this rate period; therefore, the NLSLs are assumed to remain constant from prior years through FY 2010-2011. In addition, the kWh consumption of NLSLs is assumed to remain constant through FY 2010-2011.

As described more fully below, the WP-10 Final Proposal will update the participating utilities' Contract System Cost and Contract System Load forecasts, distribution loss factors, NLSL data, and resulting ASCs with the final ASC determinations made in the ASC Review Process for FY 2010-2011.

### 6.3 Average System Cost Assumptions for FY 2010-2011

Under the normal implementation of the 2008 ASC Methodology, a utility's ASC will be established for the entire rate period prior to the commencement of BPA's rate proceeding. ASCs are determined through a 24-week ASC Review Process that begins on June 1st prior to the start of the 7(i) ratesetting process. ASCM at II.B.2. Once the ASC Review Process is complete, BPA publishes an ASC Report, which establishes the utility's final ASC. This final ASC will be used to calculate the utility's REP benefits for the term of the ASC Exchange Period, which coincides with BPA's rate period. Because the ASCs are determined prior to BPA's rate proceedings, they will generally be available to use as an input to rate cases to estimate REP costs for purposes of setting rates.

The WP-10 rate proceeding presents a unique transition-year problem. The 2008 ASC Methodology was filed with the Commission on July 7, 2008, and approved on an interim basis on September 30, 2008. Because of the timing of BPA's filing of the ASC Methodology, it was not possible for BPA to commence an ASC Review Process by June 1, 2008, to establish ASCs prior to the WP-10 Initial Proposal. To address this transition-year issue, BPA notified all parties intending to participate in the REP for FY 2010-2011 that they must file proposed ASCs with BPA no later than October 15, 2008. Eight utilities responded to this request and filed ASCs with BPA. BPA is currently reviewing these ASCs in eight separate ASC Review Processes. BPA anticipates that it will complete its evaluation and have final ASC Reports by the end of the WP-10 rate proceeding.

For purposes of the Initial Proposal, the ASCs filed by utilities on October 15, 2008, with certain modifications, are used as proxy ASCs pending the completion of the ASC Review Process. The changes to the initial filed ASCs are described in section 6.4, below. These "as filed" ASCs will be replaced with the final ASCs established in the ASC Reports published at the end of the ASC

Review Process. The final ASC Reports for FY 2010-2011 will be incorporated into the record of the WP-10 proceeding.

The following six IOUs and two COUs filed ASCs with BPA: Avista, Idaho Power, NorthWestern Energy, PacifiCorp, Portland General Electric, Puget Sound Energy, Franklin County PUD, and Snohomish County PUD.

**6.4 Changes to As-Filed ASCs for FY 2010-2011**

As noted above, for the WP-10 Initial Proposal, the rate period ASCs submitted by the participating utilities in the ASC Review Processes, with certain specified changes, are used in the rate development process. These changes are as follows. First, the forecasts of inflation, natural gas prices, and market prices are updated to be consistent with the forecast used in the WP-10 Initial Proposal. Second, the utilities' ASCs are corrected for errors found in initial review of the utilities' ASC submittals. The corrections were:

- For Avista, 1,423,334 MWh is added to the expected annual generation for its Lancaster plant, included as a new resource.
- For Franklin PUD, Franklin's forecast load growth is assumed to be met with purchases from BPA at the PF rate rather than with market purchases.
- For Snohomish PUD, the following three changes:
    1. The category of a new resource addition is changed. The new resource had been erroneously entered as a new purchased power contract and is changed to a hydro plant addition.
    2. A new resource addition date is revised to 10/1/2010 from 1/1/2011, pursuant to the ASC Methodology.
    3. The costs and MWh of a major purchased power contract that is due to expire during the rate period are removed.

Table 6.1 below lists the FY 2010-2011 revised rate period as-filed ASCs. Throughout the ASC Review Process, the submitted data will be further reviewed and analyzed. All ASC information, including the 2008 ASC Methodology, Appendix 1 ASC filings, and forecast models, is located at BPA's ASCM web site: http://www.bpa.gov/corporate/finance/ascm/.

**Table 6.1**
**FY 2010-2011 Exchange Period ASCs ($/MWh)**

| | A | B |
|---|---|---|
| **Utility** | **FY 2010** | **FY 2011** |
| Avista | 49.13 | 50.61 |
| Franklin County PUD | 43.02 | 42.55 |
| Idaho Power | 39.25 | 39.25 |
| Northwestern | 54.57 | 54.57 |
| PacifiCorp | 51.72 | 51.72 |
| Portland General | 58.05 | 59.95 |
| Puget Sound Energy | 62.13 | 64.58 |
| Snohomish County PUD | 47.72 | 45.45 |

## 6.5 ASC Forecast for Remaining Years of the 7(b)(2) Rate Test Period (FY 2012-2015)

The 7(b)(2) rate test requires a forecast of utility ASCs for the rate period (FY 2010-2011) and the following four years (FY 2012-2015). The methodology used to forecast utility ASCs for the FY 2012-2015 period is discussed in the Section 7(b)(2) Rate Test Study, WP-10-E-BPA-06, section 2.1.3.

BONNEVILLE POWER ADMINISTRATION

DOE/BP-3990 • February 2009 • 1C