Bonneville Power Administration
Power Business Line

2002 Final Power Rate Proposal
Wholesale Power Rate Development Study

WP-02-FS-BPA-05
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BONNEVILLE
POWER ADMINISTRATION

2002 WHOLESALE POWER RATE DEVELOPMENT STUDY

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COMMONLY USED ACRONYMS

AANR	Audited Accumulated Net Revenues
AC	Alternating Current
AER	Actual Energy Regulation
Affiliated Tribes	Affiliated Tribes of Northwest Indians
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
Alcoa	Alcoa, Inc.
Alcoa/Vanalco	Joint Alcoa and Vanalco
aMW	Average Megawatt
ANRT	Accumulated Net Revenue Threshold
AOP	Assured Operating Plan
APS	Ancillary Products and Services (rate)
APS-S	Actual Partial Service-Simple
ASC	Average System Cost
Avista	Avista Corp
BASC	BPA Average System Cost
BO	Biological Opinion
BPA	Bonneville Power Administration
BP EIS	Business Plan Environmental Impact Statement
Btu	British Thermal Unit
C&R Discount	Conservation and Renewables Discount
C&R	Cost and Revenue
CalPX	California Power Exchange
CBFWA	Columbia Basin Fish & Wildlife Authority
CBP	Columbia Basin Project
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAL	Columbia Falls Aluminum Company
Cfs	cubic feet per second
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
Con/Mod	Conservation Modernization Program
COSA	Cost of Service Analysis
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Critical Rule Curves
CRITFC	Columbia River Inter-Tribal Fish Commission
CSPE	Columbia Storage Power Exchange
CT	Combustion Turbine
CTPP	Conditional TPP
CWA	Clear Water Act
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause

DJ	Dow Jones
DMP	Data Management Procedures
DOE	Department of Energy
DROD	Draft Record of Decision
DSI	DSI (only the DSI represented by Murphy under DS)
DSIs	Direct Service Industrial Customers
ECC	Energy Content Curve
EFB	Excess Federal Power
EIA	Energy Information Administration
EIS	Environmental Impact Statement
Energy Northwest	Formerly Washington Public Power Supply System (Nuclear) Project
Energy Services	Energy Services, Inc.
Enron	Enron Corporation
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	Firm Energy Load Carrying Capability
FERC	Federal Energy Regulatory Commission
Fourth Power Plan	NWPPC’s Fourth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FSEA	Federal Secondary Energy Analysis
F&WCA	Fish and Wildlife Coordination Act
FY	Fiscal Year (Oct-Sep)
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
HELM	Hourly Electric Load Model
HLFG	High Load Factor Group
HLH	Heavy Load Hour
HNF	Hourly Non-Firm
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.

IPC	Idaho Power Company
IP	Industrial Firm Power (rate)
IPTAC	Industrial Firm Power Targeted Adjustment Charge
IJC	International Joint Commission
IOU	IOU (the joint IOU filings)
IOUs	Investor-Owned Utilities
ISC	Investment Service Coverage
ISO	Independent System Operator
JOA	Joint Operating Agency
Joint DSI	Alcoa, Vanalco, and DSI
KAF	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1,000 volts)
kW	Kilowatt (1,000 watts)
kWh	Kilowatthour
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LME	London Metal Exchange
LOLP	Loss of Load Probability
L/R Balance	Load/Resource Balance
m/kWh	Mills per kilowatthour
MAC	Market Access Coalition Group
MAF	Million Acre Feet
MC	Marginal Cost
MCA	Marginal Cost Analysis
MCS	Model Conservation Standards
Mid-C	Mid-Columbia
MIMA	Market Index Monthly Adjustment
MIP	Minimum Irrigation Pool
MMBTU	Million British Thermal Units
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MPC	Montana Power Company
MT	Market Transmission (rate)
MW	Megawatt (1 million watts)
MWh	Megawatthour
NCD	Non-coincidental Demand
NEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFRAP	Nonfirm Revenue Analysis Program (model)

NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPV	Net Present Value
NR	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NT	Network Transmission
NTP	Network Integration Transmission (rate)
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC C&R	Northwest Power Planning Council Cost and Revenues Analysis
NWPPC	Northwest Power Planning Council
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
OURCA	Oregon Utility Resource Coordination Association
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PATH	Plan for Analyzing and Testing Hypotheses
PBL	Power Business Line
PDP	Proportional Draft Points
PDR	Power Discharge Requirement
PF	Priority Firm Power (rate)
PFBC	Pressurized Fluidized Bed Combustion
PGE	Portland General Electric
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PMDAM	Power Marketing Decision Analysis Model
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POD	Point of Delivery
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Principles	Fish and Wildlife Funding Principles
Project Act	Bonneville Project Act
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	Public or People’s Utility District

PURPA	Public Utilities Regulatory Policies Act
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Organization
SCCT	Single-Cycle Combustion Turbine
Shoshone-Bannock	Shoshone-Bannock Tribes
SOS	Save Our Wild Salmon
SPG	Slice Purchasers Group
SS	Share-the-Savings Energy (rate)
STREAM	Short-Term Risk Evaluation and Analysis Model
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TACUL	Targeted Adjustment Charge for Uncommitted Loads
TBL	Transmission Business Line
tcf	Trillion Cubic Feet
TCH	Transmission Contract Holder
TDG	Total Dissolved Gas
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UCUT	Upper Columbia United Tribes
UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service
Vanalco	Vanalco, Inc.
VB	Visual Basic
VBA	Visual Basic for Applications
VI	Variable Industrial Power rate
VOR	Value of Reserves
WAPA	Western Area Power Administration

WEFA	WEFA Group (Wharton Econometric Forecasting Associates)
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordinating Council
WSPP	Western System Power Pool
WUTC	Washington Utilities and Transportation Commission
WY	Watt-Year
Yakama	Confederated Tribes and Bands of the Yakama Nation

1. INTRODUCTION

1.1 Purpose

The Wholesale Power Rate Development Study, WP-02-FS-BPA-05, designs rates for the Bonneville Power Administration's (BPA) wholesale power products and services.
The Wholesale Power Rate Development Study contains a Cost of Service Analysis (COSA), which allocates BPA's test period power revenue requirement to customer classes based on cost causation. The allocated COSA costs are adjusted and then used in the rate design processes for wholesale power products and services. The end results of the Wholesale Power Rate Development Study are the five-year wholesale power rates and three- and two-year stepped wholesale power rates that appear in BPA's proposed 2002 Wholesale Power Rate Schedules, WP-02-A-02, Appendix 1.

BPA's power rates are developed to recover BPA's power costs, in total, and the COSA allocates those costs (BPA's test period power revenue requirements) to each of BPA's customer classes. The COSA results are subsequently modified through rate design adjustments for the following purposes: (1) to reflect changes in BPA's rate design objectives; (2) to comport with changes in product design requirements; (3) to reflect the results of other BPA rate case studies; (4) to reflect BPA's Power Subscription Strategy; and (5) to conform with requirements of applicable legislation, including the Bonneville Project Act, 16 U.S.C. §832, the Flood Control Act of 1944, 16 U.S.C. §825s, the Regional Preference Act, 16 U.S.C. §837, the Federal Columbia River Transmission System Act (Transmission System Act), 16 U.S.C. §838, and the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. §839. BPA's power rate design objectives include recovery of BPA's projected power revenue requirements, practicality, fairness, and efficiency.

Rates for wholesale power developed in this study are based on: (1) BPA's projected test period power revenue requirements; (2) BPA’s projected test period loads and resources; (3) BPA’s projections of revenues from sales of nonfirm energy and other products to which costs are not assigned; (4) BPA’s projections of revenues from sales of unbundled products and services; (5) statutory requirements; (6) generally accepted ratemaking practices; (7) economic theory; and (8) BPA’s Power Subscription Strategy.

The test period used for setting BPA’s 2002 proposed rates is the five-year period covering fiscal years (FY) 2002 through 2006, beginning October 1, 2001, and ending September 30, 2006. It is assumed for ratemaking purposes that most of BPA’s customers will sign Subscription Contracts for either 3, 5, or 10 years. Power rates are being established for the stepped rate period (three- and two-year) and five-year periods. Contracts may have varying rate terms. Some of BPA’s preference customers have signed Pre-Subscription Contracts for the FY 2002 through 2006 test period.

As noted in (8) above the results of the Power Subscription Strategy has been a major influence in developing Power rates for the rate case. Between March 1997 and August 1998, BPA and interested regional parties met regularly to develop a strategy for selling, also known as “subscribing,” Federal power to the region in the post-2001 period. On September 18, 1998, BPA released its proposed Power Subscription Strategy for public comment. After reviewing the comments received from interested parties and revising the proposed Strategy based on those comments, the Administrator issued a final Power Subscription Strategy and accompanying Record of Decision (ROD) on December 21, 1998. Parts of the Strategy include:

(1) All net requirements loads of public agency customers, including loads of new public agencies and annexed loads, which are contracted for during Subscription window ending September 30, 2000, will be served at the Priority Firm Power (PF) rate.

(2) During the FY 2002 to 2006 rate period, as a proposed settlement of the Residential Exchange Program (REP), BPA has developed rates which will allow the investor-owned utilities (IOU) access to 1,900 average megawatt (aMW) of Federal power for their residential and small farm consumers. Of this amount, at least 1,000 aMWs will be met with actual power deliveries. The remainder may be provided through either a financial arrangement or additional power deliveries, depending on which approach is most cost-effective for BPA. The proposed Residential Exchange Settlement is discussed further in section 2.16 below.

(3) BPA expects to be able to serve all direct service industrial customers (DSI) loads placed on it. *See* Section 2.2.4 of the Loads and Resources Study, WP-02-FS-BPA-01 for a discussion of the DSI sales forecast. For a discussion of the BPA's policy for sales to the DSIs *see* Berwager *et al.*, WP-02-E-BPA-09 and Berwager *et al.*, WP-02-E-BPA-46.

(4) BPA recognizes that during the rate period short-term purchases will be needed to augment the Federal Base System (FBS) resources. System augmentation is discussed in section 3.2.1.2.3 below.

(5) BPA will offer a Conservation and Renewables Discount (C&R Discount) as an incentive for customers to support conservation and renewables through local action. The C&R Discount is discussed in section 2.10 below. In addition, to meet the needs of

environmentally conscious customers, BPA will offer the Green Energy Premium (GEP). The GEP is discussed in section 2.11 below.

(6) BPA will work to develop rates that are similar for BPA customers. This is discussed in sections 2.17 and 3.4 below.

(7) BPA will make efforts to mitigate rates to customers that are adversely impacted by rate design changes. This is discussed in section 2.8 below.

1.2 Overview of the Studies and the Rate Analysis Models

1.2.1 Overview of the Studies. The Wholesale Power Rate Development Study calculates BPA's proposed rates based on information either developed in the Wholesale Power Rate Development Study or supplied by the other studies that make-up BPA's final rate proposal. All of these studies, and accompanying documentation, provide the details of computations and assumptions. In general, information about loads and resources is provided by the Loads and Resources Study, WP-02-FS-BPA-01, and the Loads and Resources Study Documentation, WP-02-FS-BPA-01A. Revenue requirements information, as well as the Planned Net Revenues for Risk (PNNR), are provided by the Revenue Requirement Study, WP-02-FS-BPA-02, and its accompanying Revenue Requirement Study Documentation, WP-02-FS-BPA-02A and WP-02-FS-BPA-02B. The Risk Analysis Study, WP-02-FS-BPA-03, and the Risk Analysis Study Documentation, WP-02-FS-BPA-03A, provide short-term balancing purchases and secondary energy revenue credits. The Marginal Cost Analysis Study, WP-02-FS-BPA-04, and the Marginal Cost Analysis Study Documentation, WP-02-FS-BPA-04A and WP-02-FS-BPA-04B, provide the Wholesale Power Rate Development Study with information regarding seasonal and diurnal differentiation of energy charges, as well monthly differentiation for Demand Charges. In addition, this study provides information in the pricing of unbundled power products. The Section 7(b)(2) Rate Test Study, WP-02-FS-BPA-06, and the Section 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A, implement Section 7(b)(2) of the Northwest Power Act to ensure that BPA's preference customers' firm power rates applied to their general requirements are no higher than rates calculated using specific assumptions in the Northwest Power Act.

1.2.2 Overview of the Rates Analysis Model. BPA uses a linked spreadsheet modeling process for the 2002 rate proposal. *See* section 1.0 of Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A, for a summary of the ratesetting process and accompanying flowchart. This group of computer applications is referred to as the Rate Analysis Model (RAM). The initial spreadsheet of the RAM is the Input model. This model accumulates all source data and assumptions and directs the information to the RAM Program Case and the RAM 7(b)(2) Case.

The Residential Exchange Rate Analysis Model (RESEXRAM) calculates the gross and net exchange costs utilized in the RAM. The 7(b)(2) Case of the RAM calculates rates using costs and loads which are limited by section 7(b)(2) of the Northwest Power Act. The Program Case of the RAM uses information from all the previous models to develop posted rates for each of the customer groups. The output of RAM consists of a series of tables, each of which shows a sequential step in BPA's rate development process. Section 2 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A, includes the RAM tables and supporting documentation. Also included in the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A, are those rate calculations not performed in the RAM, such as Load Variance and Demand Charges. *See* section 2.3 below and sections 4.1 and 4.2 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

1.3 Organization

The Wholesale Power Rate Development Study is divided into six sections including this introduction. These sections are: Rate Design Changes; Cost Allocation and Rate Design Implementation; Inter-Business Line Revenues and Expenses; Revenue Forecast; and Rate Schedule Descriptions. In addition, the Wholesale Power Rate Development Study includes three appendices. These are the 7(c)(2) Industrial Margin Study; the Value of DSI Supplemental Contingency Reserves; the Nature of the Slice of the System (Slice Product). Details of calculations and data are in the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A and WP-02-FS-BPA-05B.

BPA’s 2002 rate proposal includes changes in the calculation and design of wholesale power rates. A primary purpose of these changes is to accommodate the transition from the 1981 utility and DSI customer contracts to BPA’s proposed Subscription contracts. Since 1981, the wholesale electric marketplace has experienced significant changes, namely, deregulation and the unbundling of products and services. Therefore, BPA has included several new products and services that are intended to meet the demands of a more competitive electric utility marketplace and which better serve the needs of BPA’s regional customers. In doing so, BPA has also revised its rate design to reflect cost causation more accurately and to provide price signals that will result in more efficient use of the FBS, which enables potential purchasers to compare BPA’s products and services with those of alternative supplier

The primary changes in BPA’s Power rate design are as follows:

(1) Customers have the option of signing Subscription contracts with varying rate terms. These contracts will have stepped rates for the five-year rate period, in addition to a five-year average rate option. This issue is discussed further in sections 2.1 and 3.5 below.

(2) BPA has revised the six seasonal periods used in BPA's 1996 rates to monthly periods for energy and demand. This is discussed below in section 2.2.

(3) BPA continues to use market forecasts in developing the monthly Demand Charge in order to send more accurate price signals to customers. This is discussed further in section 2.3.1.1 below.

(4) BPA will measure monthly peak for customers purchasing the Full Service Product on the customer's monthly peak coincident to BPA's monthly system peak. Customers purchasing the Actual Partial Product will have their monthly peak measured on their system peak. This is discussed in section 2.3.1.1, Table 1 below.

(5) The Load Shaping Charge has been eliminated and replaced by the Load Variance Charge. The primary cost drivers of the Load Variance Charge are based on the customer's right to place load growth on BPA and load variations due to weather. Further discussion of this change is in section 2.3.4 below.

(6) BPA has developed rates that are similar for BPA customers. This is discussed below in sections 2.17 and 3.4.

2. RATE DESIGN

2.1 Five-Year Average and Stepped Rates

BPA has developed five-year average power rates. In addition, to encourage staggered contract terms, BPA has established stepped power rates for the five-year rate period FY 2002-2006. These posted rates will step-up by 1.5 mills/kilowatthour (kWh) after FY 2004. The RAM calculates average rates for the five-year rate period and then steps those average rates. Rates for the first three years are set at 0.6 mills/kWh below the average five-year rate. Rates for the remaining two years are set at 0.9 mills/kWh above the average five-year rate. Stepped rates will apply to the PF-02 Preference and New Resource Firm Power (NR-02) rate schedules.

Customers that sign contracts with terms of five years or longer will be subject to the stepped rates calculated in this rate case. In addition, they have the option to take service under the five-year average rates. Customers with three-year contracts may be subject to rates calculated in a subsequent rate case for their power purchases after FY 2004.

The five-year average PF-02 Preference rate will be used to determine the price for firm power sold under Pre-Subscription contracts with collared price provisions. The PF-02 Exchange Program rate is compared to the exchanging utilities' Average System Cost (ASC) to determine REP benefits. Since exchanging utility ASC are not stepped, the PF-02 Exchange Program Rate, as well as the Residential Load Power Rate (RL-02), is not stepped. In addition the Industrial Firm Power (IP-02) rate is not be subject to stepped rates.

2.2 Monthly and Diurnal Differentiation of Energy Charges

In establishing rate design for FY 2002-2006, BPA used the same basic approach that was used in BPA's 1996 rate case. More specifically, BPA shaped energy rates according to market-based marginal costs established by BPA's market forecast for the FY 2002-2006 period. BPA's power revenue requirements reflect the costs associated with the market for at least three reasons: (1) BPA now operates in open wholesale markets that are becoming more competitive over time; (2) increased volatility of west coast energy prices; and (3) less flexibility in operating BPA's system to meet firm power loads due to constraints imposed on the system to save anadromous fish. These costs must be recovered in BPA's Power rates.

BPA is setting monthly energy rates for the FY 2002-2006 rate period. The Marginal Cost Analysis Study, WP-02-FS-BPA-04, shows substantial monthly differentiation in predicted energy rates for this period. Therefore, it is not appropriate for BPA to have less than 12 seasons for Heavy Load Hour (HLH) and Light Load Hour (LLH) energy rates. This is a change from 1996, where BPA had six seasons for energy rates.

BPA established HLH and LLH energy rates for FY 2002-2006 using the following five steps:

(1) BPA estimated its market energy prices for HLH and LLH for each month using marginal costs for the FY 2002-2006 rate period (*see* Marginal Cost Analysis Study, WP-02-FS-BPA-04);

(2) Monthly demand rates were calculated using the results from the Marginal Cost Analysis Study, WP-02-FS-BPA-04 (*see* section 2.3.1.2 below). The Demand Charges are significantly higher than the 1996 Demand Charges, in large part due to a significant reduction in

west coast surplus capacity. BPA capped monthly Demand Charges at $2.50 per kW-month. BPA then proportionately scaled back monthly Demand Charges until an average annual Demand Charge of $2.00 per kW-month was achieved. These adjustments have the effect of mitigating the increase in Demand Charges. The policy issues regarding capping the Demand Charges are discussed in Burns *et al*., WP-02-E-BPA-08; and Burns *et al*., WP-02-E-BPA-37;

(3) The Load Variance Charge was calculated using the results from the Marginal Cost Analysis (MCA) (*see* section 2.3.4 below). To reduce the impact of the Load Variance Charge on the effective rate paid by BPA's customers, BPA capped the Load Variance Charge at 0.80 mills/kWh times Total Retail Load (TRL) (*see* Burns *et al*., WP-02-E-BPA-08; and Burns *et al*., WP-02-E-BPA-37; Keep *et al*., WP-02-E-BPA-17; and Keep *et al*., WP-02-E-BPA-43);

(4) Estimated FY 2002-2006 demand and load variance revenues were subtracted from BPA's FY 2002-2006 revenue requirement; and

(5) Monthly HLH and LLH energy rates from the Marginal Cost Analysis Study, WP-02-FS-BPA-04, were reduced proportionately until estimated revenues from energy charges equaled the balance of BPA's power revenue requirements, to ensure BPA did not overcollect revenues.

2.3 Relationship Between Rate Design and Core Subscription Products

The purpose of this section is to discuss changes in rate design and the relationship of these issues with BPA's Core Subscription Products. This section will discuss Demand, Load Factoring, and Load Variance.

2.3.1 Core Subscription Products Principles. BPA designed its 2002 rates with a new approach that encompasses equitable comparability among purchasers, a common table of rates, and the concept of an effective rate. BPA then incorporated these elements into BPA's Core Subscription Product design. The relationship between the Core Subscription Products and the proposed rate design is more direct than in BPA's 1996 rate filing. This new design approach primarily concerns two rate design items known as the Demand Charge and the Load Variance Charge.

BPA's Core Subscription Products are developed based on the principle that Core Products will be billed from a "common table of rates" to assure equitable comparability of payment among purchasers of different types of Core Products. The common table of rates includes demand, HLH and LLH energy rates, and a charge for Load Variance, where applicable. The common table of rates is associated with a table of billing factors showing the billing determinants appropriate to the specific products. *See* BPA Power Products Catalog, Appendix B, Core Product Billing Factors.

2.3.1.1 Demand Charges for Core Subscription Products. The purpose of the Demand Charge 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 service BPA calls "factoring" in which energy is distributed among hours to match a load shape; and (3) readiness to meet actual load under peaking conditions. When combined with energy charges, a Demand Charge has the effect of increasing the purchaser's average payment per kWh of product, sometimes referred to as the effective rate. If the power delivery is not flat, the resulting demand charge plus energy charge makes the effective rate increase or decrease compared to a flat power purchase. To help maintain and assure equitable comparability, the same demand dollar rate ($/kW-month) will be applied to appropriate demand billing factors for different products such as Full Service, Partial Service, and Block products.

2.3.1.2 Development of Power Rates Demand Charge. BPA is proposing only two energy charges for each month. However, the MCA demonstrates there is a different market value for power in each hour. To account for the hourly differential, BPA is proposing a Demand Charge applied in conjunction with the energy rate. The effect of this combination results in a shaped load paying a higher effective rate than a flat load. This is consistent with generally accepted ratemaking principles of sending price signals.

2.3.1.2.1 Methodology. The methodology to derive a demand charge uses the AURORA market price forecast as a basis. The delta above annual average prices is the value used to approximate the Demand Charge. The AURORA market model simulates serving all loads and recovering all costs through hourly energy prices. A single hourly energy price could be computed, that would have recovered all costs. The problem with this would be that the peaking loads causing the average price to be higher would only pay an average price and would not pay their fair share. The higher costs identified are those costs above the annual average price. The demand charge reflects these higher hourly costs. For AURORA prices *see* the "Hourly Data" Table in Marginal Cost Analysis Study Documentation, WP-02-FS-BPA-04A.

The Demand Charge was developed from AURORA market prices as follows (*see* section 4.2, "Demand Charge" Table in Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B).

(1) The deltas of hourly prices above the annual average are computed and averaged monthly, and they reflect the value of firming, factoring, and peaking costs.

(2) These monthly average prices are averaged for each year of the rate period yielding a value in mills/kWh.

(3) This annual value is converted to a $/kW-year value by multiplying by the number of HLH in a year and dividing by 1,000. For each year the $/kW-year value is divided by 12 to get five yearly $/kW-month values. These $/kW-month values are then averaged over the five-year rate period.

(4) This average $/kW-month value is shaped to AURORA onpeak market prices by month to derive a monthly market-based Demand Charge.

(5) In order to mitigate the rate impact relative to 1996 Demand Charges, these market-based Demand Charges were capped at $2.50/kW-month. The annual average market-based Demand Charge was further capped at $2.00/kW-month resulting in scaled down monthly Demand Charges. *See* Burns *et al*., WP-02-E-BPA-08; and Burns *et al*., WP-02-E-BPA-37; Keep *et al*., WP-02-E-BPA-17; and Keep *et al*., WP-02-E-BPA-43.

2.3.1.2.2 Results. The five-year annual average Demand Charge is $2.00/kW-month. Monthly rates are as stated in the rate schedules. *See* Wholesale Power Rate Schedules, WP-02-A-02, Appendix 1.

2.3.2 Factoring Service in Core Subscription Products. The term "factoring" is a term of general usage in the utility industry; however, for purposes of the Core Subscription Products, it is specifically defined as the BPA service of shaping a given quantity of megawatthours (MWh) among hours during certain periods to follow load. The term "periods" refers to the HLH and LLH periods of rate seasons, *e.g.*, calendar months and years. 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 percentage drops lower, 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 change in the load factor.

The Factoring Service is a part of both the Full Service and the Actual Partial Service products as explained below. However, as the BPA Power Product Catalog explains, the amount of Factoring Service taken will only be checked in the billing process for customers with declared resources with hourly variability, which are dispatchable, and whom purchase the Actual Partial (Complex) product. This is because customers without resources, or 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 which are less than or greater than the entitlement amount. BPA's posted product descriptions provide further details on the factoring benchmark calculation. Factoring Service that is within the benchmark triggers no excess service penalty charges. The entitled amount of Factoring Service will be paid for at BPA's posted power Demand Charge 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 control area, the power product default treatment is to identify that as an unauthorized increase event. By arrangement, other BPA services could apply, such as an ancillary services acquired by the customer from BPA's Transmission Business Line (TBL) or a negotiated backup service.

2.3.2.1 Factoring Service as a Staple-On Product and the Appropriate Billing Demand. BPA's 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 by the Demand Charge applied to an appropriate demand billing factor.

2.3.3 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 on the hour of the Monthly Federal System Peak Load as they were under BPA's 1996 rate schedules. 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. This was the case in BPA's 1996 rate filing for the rates that applied to customers purchasing partial service under 1981 power sales contracts. However, BPA does not wish to abandon the concept of a common table of rates or to create a lack of equitable comparability. This would be the result if customers were billed at the same dollar rate on different billing demands.

The Demand Adjuster was developed to resolve this problem by adjusting billing demand megawatts (MW) to achieve parity with a customer whose billing demand is set on BPA's generation system peak (GSP). Because a customer's system peak is always equal to or larger than its load on the hour of the Monthly Federal System Peak, this larger billing factor for this type of customer, if not adjusted, would result in lower 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 TRL on the hour of the Monthly Federal System Peak Load by the customer's TRL on its system peak. The minimum Demand Adjuster is 0.6 (six tenths). This floor protects BPA's demand revenue from unforeseen circumstances, such as occurred in the 1996 rate case when the Utility Factor resulted in a billing factor of zero for some customers.

2.3.4 Load Variance Charge. In the context of Core Subscription Products, Load Variance is defined as the variability in monthly energy consumption within the BPA 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 the customer's actions to annex new load, or variance in load due to retail access, or variance caused by service to New Large Single Loads (NLSL). Such loads will receive Load Variance coverage once the loads are served by BPA under the applicable firm power rate. BPA offers to stand ready to serve this 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 to be paid for are fixed in advance.

The Load Variance Charge is set at 0.80 mill/kWh and will be charged against the customer's TRL. For a discussion of the basis for the calculation of the Load Variance Charge, *see* section 2.3.4.1.

Similar to the PF-96 and NR-96 Load Shaping charge, the Load Variance billing factor is the customer's TRL; however, there are some differences between the underlying concepts for Load Variance and Load Shaping as unbundled components. Because of the Subscription product component called factoring, the Load Variance Charge is not linked to the services of providing hourly, daily, or other period variability as Load Shaping was in the 1996 rate schedule. In the proposed rate filing and associated Subscription products, the Load Variance Charge is associated solely with the service of standing ready to meet variable monthly cumulative energy amounts. For this reason, it is not proposed to be applicable to Block or Slice purchases.

2.3.4.1 Development of Power Rates Load Variance Charge

2.3.4.1.1 Methodology. The methodology for the Load Variance Charge approximates the amount of incremental or marginal cost risk BPA must bear in providing Load Variance service. The risk is standing ready to serve an unknown quantity at an unknown cost, but at a fixed price. When loads are above or below the forecast, BPA could purchase or sell in the market at an unknown price. Call and put options guarantee the right to purchase or sell at fixed prices, removing price uncertainty. As described here, BPA considered and used the values of the options to approximate the cost of standing ready to serve uncertain deviations in loads.

Load growth amounts, for other than annexation and retail access load gain or loss, are computed from five-year monthly TRL forecasts. The Northwest Power Planning Council's (NWPPC) forecast of public and Federal agencies' TRL was used as the basis for projecting BPA's PF sales. *See* Loads and Resources Study Documentation, WP-02-FS-BPA-01A.

The additional load BPA is committed to serve is the increase in load for each month that is above the first year's forecast. The cost to BPA to serve this additional load was valued as a call option using the Black-Scholes equation with the AURORA market price forecast in the Final Proposal (*see* Marginal Cost Analysis Study Documentation, WP-02-FS-BPA-04A) and the final PF-02 rates (Wholesale Power Rate Schedules, WP-02-A-02, Appendix 1). The quantity of load growth is computed for each diurnal period by month in MWhs. The call option price is computed by diurnal period by month in dollars per MWh. The total cost is the sum of the load growth times the call option price for each diurnal period of each month of the rate period.

Load variation for the difference between forecasted and actual loads was estimated by comparing regional load forecasts for generating and non-generating public utilities to subsequent actual loads for the period October 1990, through September 1995. The forecasted loads came from BPA's 1991 Final Rate Proposal, and are shown in the Table titled, Comparison of Forecasts to Actual, located in the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

Actual load averaged 3.7 percent above the forecast when the monthly forecast was low and 0.4 percent below the forecast when the monthly forecast was high. The quantity of variablity is computed for each diurnal period by month in MWh using these percentages and the TRL forecast. *See* Table titled, Comparison of Forecasts to Actual, located in the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B. Variation in load above forecast uses call option pricing to determine stand ready costs while variation in load below the forecast uses put option pricing. The above and below variation quantities are multiplied by their respective call and put option prices as computed by month and diurnal period in $/MWh. The sum of these above and below variation values is the total cost for load variation.

The load growth and load variation quantities, PF-02 rates, AURORA market prices, months until expiration, monthly and daily volatilities, resulting option values and costs are shown in section 4.1, "Load Variance Charge Table" of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

The Black-Scholes Option pricing requires inputs for stock market price, strike price, risk free interest rate, time until expiration, and volatility. The inputs are market price using the AURORA market price forecast; strike price using PF-02 rates; risk free interest rate of 6.8 percent; time until expiration using number of months from date of pricing until date of delivery; and volatility using monthly volatility estimated from historic market prices. The near-term volatilities are extrapolated to get future volatilities that result in an annual average volatility of 15 percent for October 2005, through September 2006. The volatility for the last year of the rate period is an estimate from BPA's risk management group. *See* Black-Scholes equations in table titled "Load Variance Charge," in the Wholesale Power Rate Development Study. *See* section 4.1 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

2.3.4.1.2 Results. The charge for Load Variance is the sum of the load growth and load variation costs divided by the TRL including load growth. The cost is 1.02 mills/kWh. *See* Table titled "Load Variance Charge. *See* Section 4.1 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B. This cost is multiplied by a customer's TRL including any annexation and retail access load gain or loss. In order to mitigate the rate impact this charge would have relative to the 1996 rates, this charge has been capped at 0.80 mills/kWh. *See* Burns *et al*., WP-02-E-BPA-08. The Load Variance Charge is published in the Wholesale Power Rates Schedules, WP-02-A-02, Appendix 1, and applies to the PF-02 and NR-02 rate schedules.

2.3.5 Stepped-Up Multiyear (SUMY) Charge for Block Purchases. The SUMY Block charge will apply to Block purchases if the annual amounts increase (*i.e.*, step-up) over multiple years of a purchase commitment term due to increases in a customer's net requirement that are not subject to a Targeted Adjustment Charge (TAC). For a discussion of the methodology for the SUMY charge, *see* the section 2.3.5.2 below.

BPA's Core Subscription Product description for the Block product defines the maximum annual purchase amount as an amount equal to the customer's annual net requirement for each year of the term of commitment as established at the time of commitment. The Block product description provides that the maximum Block purchase amounts are the differences between the customer's reasonably estimated TRL and the reasonably estimated capabilities of the customer's firm peaking and energy resources, except where otherwise indicated. Resource capabilities will be determined consistent with the Resource Declaration Parameters listed for the Actual Partial Service Product, including the provisions of BPA's Final Policy on Subscription Power Sales to Customers and Customers' Sales of Firm Resources (*see* Fed. Reg. at 24382 (May 6, 1999)). The resource capabilities for the years of the term of the Block purchase commitment will reflect, to the extent appropriate, permanent loss of resource consistent with BPA's final policy on Subscription Power Sales to Customers and Customers' Sales of Firm Resources. The SUMY Block charge is associated with a Block purchase that steps up over its multiyear term. It is applicable to the basic Block purchase energy even if the purchaser also selects a Subscription staple-on product such as Factoring or Shaping Capacity. These two staple-on products provide for some nonflat delivery of the Block energy across hours, but they do not change the fixed amount of Block energy. The SUMY Block charge is applied to the total multiyear block purchase energy including the stepped-up amounts.

The SUMY Block charge does not permit the customer to make within-term changes to the amount purchased under the Block product for increases in load resulting from annexed loads. The charge only compensates BPA for the estimated cost of serving a multiyear Block that steps up over years, declared prior to the Subscription Contract signing. A customer may request BPA to serve new load under its Subscription Contract. Increases in the customer's load due to annexations and retail access load gain that occur after the Subscription window closes, however, will be subject to a TAC to their applicable firm power rate.

2.3.5.1 Development of the SUMY Block Charge. The charge associated with the increased block amounts is the difference between PF-02 and the market. The SUMY Block formula charge is published in the Adjustments, Charges, and Special Rate Provisions of the Wholesale Power Rate Schedules and applies to the PF-02 and NR-02 rate schedules. *See* Wholesale Power Rate Schedules, WP-02-A-02, Appendix 1.

2.3.5.2 Methodology. The methodology approximates the incremental cost BPA must bear in providing the SUMY Block. BPA plans to purchase in the market to serve eligible (SUMY) Blocks that are subscribed to during the Subscription window. The market used to estimate the cost and set the SUMY Block load charge is the AURORA monthly on and offpeak market price forecast in the final rate proposal (*see* Marginal Cost Analysis Study, WP-02-FS-BPA-04). The cost for the SUMY Block service is the difference between the PF or NR rate and the AURORA market prices.

The starting basis for computing the SUMY Block quantities will be the purchaser's subscribed block amount for the period October 2001, through September 2002. Costs will be computed for 24 monthly blocks (12 HLH and 12 LLH) for each year of the rate period. Each year's monthly amount above the base year's monthly amount is the stepped-up quantity.

Total cost is the sum of each month's HLH and LLH stepped-up quantities times each month's HLH and LLH costs.

2.3.5.3 Results. The SUMY charge is the total cost of the SUMY Block service divided by the total Block energy purchase including stepped-up amounts. The SUMY charge is a formula that reflects the cost of the purchaser's actual subscribed increasing block limited by their net requirements eligibility. The charge is in addition to the PF and NR energy and demand rates that the customer will pay for these power purchases. The formula charge is published in the Wholesale Power Rate Schedules, WP-02-A-02, Appendix 1, General Rate Schedule Provisions (GRSPs), Section II.S.

2.4 Unauthorized Increase Charges and Excess Factoring Charges

This power rate proposal includes separate penalty charges for Unauthorized Increases in Energy; Unauthorized Increases in Demand, Excess Within-Day Factoring Energy, and Excess Within-Month Factoring Energy. These charges apply to deliveries that exceed contractual entitlements for demand, energy, and factoring, respectively.

Elements common to these penalty charges are described here. BPA has also proposed minimum penalty charges for Energy, Demand, and Excess Factoring, with the potential for relevant price indexes 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 (ISO) 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 indexes in the penalty charge derivations also ensures an appropriate deterrent against customers placing demand, energy, and factoring burdens on BPA's 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 remote possibility that one or more of the currently identified indices for determining the penalty charges will cease to exist during the rate period. The proposed GRSPs account for this possibility by allowing replacement indices, either some index already in existence (*e.g.*, the California Power Exchange (CalPX)) or some other relevant future index available at some point during the rate period. *See* Wholesale Power Rate Schedules, WP-02-A-02, Appendix 1, GRSPs, Section II. and II.W.

BPA will also provide a reduction in charges associated with single occurrences that trigger multiple penalties. Specifically, there will be reductions to Excess Within-Month Factoring Charges to the extent that energy in the same diurnal period is assessed the Unauthorized Increase in Energy Charge.

2.4.1 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 charge for a given month will be the highest DJ Mid-C Index price for firm power or the highest California ISO Supplemental Energy price for that month, whichever is greater. The minimum charge will be set at 100 mills/kWh.

The charge for Unauthorized Increase in Demand will be applied for any purchaser taking demand in excess of its contractual entitlement. The minimum charge will be set at three times the monthly Demand Charge from the applicable power rate schedule. The effective charge may be set at a level that exceeds the minimum based on the hourly California ISO Spinning Reserve Capacity prices for the month. The sum of hourly Spinning Reserve Capacity prices during all HLH of the month will be tested against the minimum and, if higher than the minimum, will determine the effective penalty charge for demand. Details on these charges are found in the Wholesale Power Rate Schedules, WP-02-A-02, Appendix 1, GRSPs, Section II.V.

2.4.2 Excess Factoring Charges. This rate proposal includes two separate charges for Excess Factoring: the Excess Within-Day Factoring Charge and 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 kWh, 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 for each month will be 5 mills/kWh, although it is likely that the charges may be higher, as defined by hourly ISO Supplemental Energy prices. For HLH, the highest Within-Day difference during the month between: (1) the highest hourly price, and less (2) the lowest (same day) hourly price will be tested against the 5 mills/kWh minimum to determine the applicable charge. A corresponding test against the 5 mills/kWh minimum will be applied for LLH to determine the LLH Excess Within-Day Factoring Charge.

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

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 (*see* 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, however, is equipped to address such an event. 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 amounts greater than the upper boundary; or (2) the sum of the amounts less than the lower boundary. There will be a separate quantification of Excess Within-Month Factoring for HLH and of Excess Within Month-Factoring for LLH. The minimum charge for Excess Within-Month Factoring will be 5 mills/kWh. This minimum will be tested against charges derived from the DJ Mid-C Index prices for firm power and the California ISO Supplemental Energy indexes for the month. For HLH Excess Within-Month Factoring Energy, the effective charge will be the greater of: (1) 5 mills; (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 ISO Supplemental Energy price among all HLH periods for the month and the lowest average hourly ISO Supplemental Energy HLH price. An equivalent test against the five mill minimum price will be done to determine the effective Excess Within-Month Factoring for LLH.

The Excess Within-Month Factoring quantities are reduced by any Unauthorized Increase in Energy amounts in the same diurnal period and only the residual is charged the Excess Within-Month Factoring Charge. Details on these charges are found in the Wholesale Power Rate Schedules, WP-02-A-02, Appendix 1, GRSPs, Section II.I.

2.5 Flexible PF and NR

The Flexible PF and NR rate option is offered at BPA’s discretion to PF and NR Preference purchasers who make a contractual commitment 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 a purchaser under this option. The actual charges and billing factors will be mutually agreed to by BPA and the purchaser subject to satisfying the following condition:

- Equivalent Net Present Value Revenues: Forecasted 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.

2.6 PF Exchange Rates

BPA has established two PF Exchange rates in the current rate proceeding: (1) the PF Exchange Program rate; and (2) the PF Exchange Subscription rate. The PF Exchange Program rate applies to the traditional implementation of the REP. The PF Exchange Subscription rate applies to in-lieu sales to exchanging IOUs that participate in a settlement of the REP as described in BPA's Subscription Strategy.

The PF Exchange Program rate applies to the traditional implementation of the REP. This rate is compared with the exchanging utility's ASC and the difference is multiplied by the utility's eligible RL to determine monetary benefits paid to the utility by BPA. This rate also applies to BPA's actual power sales to exchanging utilities under traditional "in-lieu" transactions. The proposed PF Exchange Program rate is established at an average posted level for the five-year rate period. The PF Exchange Program rate is not "stepped" in three- and two-year increments.

The PF Exchange Program rate Demand Charge is the same as the PF Preference rate Demand Charge. The PF Exchange Program rate energy charges are seasonally differentiated identically to the PF Preference rate energy charges. The PF Exchange Program rate includes a charge for

Load Variance. A charge for Load Regulation or its successors, as established by BPA's TBL, and the Network Integration Transmission (NT) rate or its successor for transmission service, also as established by TBL, are forecasted and included in the initial proposed PF Exchange Program rate. The actual Load Regulation charge and NT rate, as established by the TBL, will be used in determining the PF Exchange Program rate during the rate period.

The PF Exchange Subscription rate applies to in-lieu sales to exchanging IOUs that participate in a settlement of the REP as described in BPA's Subscription Strategy. The proposed settlement involves providing the equivalent of 1,900 aMWs of Federal power to regional IOUs for their residential and small farm customers. Of this 1,900 aMWs, at least 1,000 aMWs would be actual power sales and the remaining 900 aMWs would be provided in either power or in a monetary payment, depending on which is most cost-effective for BPA. Because BPA has not yet determined whether Subscription settlement power sales to the IOUs will be pursuant to section 5(b) (net requirements sales) or section 5(c) (in-lieu sales) under the Northwest Power Act, BPA must develop rates that apply to each alternative. In the current rate case, BPA is proposing that the rate for requirements power sales will be the RL-02 rate (*see* section 2.7) and the rate for in-lieu power sales will be the PF Exchange Subscription rate. The proposed PF Exchange Subscription rate is established at an average level for the five-year rate period.

The PF Exchange Subscription rate Demand Charge is the same as the PF Preference rate Demand Charge. The PF Exchange Subscription rate energy charges are seasonally and diurnally differentiated identically to the PF Preference rate energy charges. The PF Exchange Subscription rate does not include a charge for Load Variance. A charge for Load Regulation or its successors, as established by BPA's TBL, and the NT rate or its successor for transmission service, as established by TBL, are also not included in determining the PF Exchange

Subscription rate. If actual Subscription power sales to IOUs are made, the IOUs will pay applicable transmission charges for the transmission of such power.

2.7 Residential Load (RL-02) Rate

BPA proposes to apply two rates for net requirements firm power sales to the IOUs. One rate is the NR-02 rate, which applies to traditional net requirements sales to IOUs. BPA also proposes to establish the RL-02 rate. This rate applies to net requirements sales to IOUs that participate in a settlement of the REP as described in BPA's Subscription Strategy.

In the current rate case, BPA is proposing that the rate for requirements power sales will be the RL-02 rate and the rate for in-lieu power sales will be the PF Exchange Subscription rate (*see* section 2.6). The proposed RL-02 rate is established at an average level for the five-year rate period.

The RL-02 rate Demand Charge is the same as the PF Preference rate Demand Charge. The RL-02 rate energy charges are seasonally and diurnally differentiated identically to the PF Preference rate energy charges. The RL-02 rate does not include a charge for Load Variance. A charge for Load Regulation or its successors, as established by BPA's TBL, and the NT rate or its successor for transmission service, as established by TBL, are also not included in determining the RL-02 rate. If actual Subscription power sales to IOUs are made, the IOUs will pay applicable transmission charges for the transmission of such power.

2.8 Rate Mitigation

BPA's Power Subscription Strategy ROD (Subscription ROD) states that "BPA has decided to offer to negotiate Firm Power Products and Services (FPS) contracts with small rural full service customers with heavy irrigation load, if rate design changes have inordinate effects on these customers." *See* Subscription ROD at 27. Consistent with this decision, BPA has included $4 million in costs to mitigate adverse rate impacts on such customers. *See* Burns *et al.*, WP-02-E-BPA-08.

2.9 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. Such purchasers are utilities with low system densities, such as rural electric cooperatives, with high distribution costs resulting from sparsely populated service areas. The LDD principles, eligibility criteria, and discount calculation table appear in the Wholesale Power Rate Schedules, WP-02-A-02, Appendix 1, GRSPs, Section II.P.

The LDD is determined by a formula that computes two ratios. One formula calculates a qualifying utility's ratio of TRL to its depreciated electric plant, excluding generation plant (K/I). The other formula calculates the ratio of the number of the utility's consumers to the number of pole miles of distribution lines (C/M). These ratios are determined based on data submitted by the purchaser based on the purchaser's entire electric utility system in the Pacific Northwest (PNW). For purchasers with service territories that include any areas outside the PNW, BPA shall compile data submitted by the purchaser separately on the purchaser's system in the PNW and on the purchaser's entire electric utility system inside and outside the PNW. BPA will apply 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 will be 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 0 to 5 percent, in one-half percent increments. 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 7 percent.

The 1996 LDD methodology has been modified to simplify the implementation of the LDD. The modifications will not cause an overall reduction in LDD benefits. As in the previous rate period, the new discount for any eligible utility will be ramped in from the existing discount. No eligible utility will experience more than a one-half percentage point change (positive or negative) in its LDD beginning October 1, 2001, and each succeeding FY, 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.

In BPA's 1996 rates, BPA accounted for the LDD in the ratemaking process by adjusting the load forecast to reflect the anticipated impact of the LDD in the RAM. However, in BPA's proposed 2002 rates, BPA is no longer forecasting individual purchaser loads. *See* Loads and Resources Study, WP-02-FS-BPA-01. Therefore, a new method to account for the LDD in the RAM was needed. As documented in the Revenue Forecast chapter of this Study, the LDD is now incorporated in the revenue forecast methodology for BPA's 2002 rates. *See* section 5.4.1.1.

The estimated cost of the LDD is $14 million per year for the FY 2002-2006 rate period. There are a number of other proposed changes to the LDD for the FY 2002-2006 rate period:

(1) In the K/I ratio, TRL will be used to define K. This change is necessary to keep K constant in a retail access environment and thereby avoid increases in LDD costs as a result of a purchaser losing load to another supplier through retail access.

(2) A "Retail Access Exclusion" has been added. This exclusion precludes LDD benefits for a purchaser's new load where the acquisition of the new load occurs as a result of retail access legislation enacted by the Federal Government or a state or local government.

(3) BPA has explicitly identified the rate schedules eligible to receive the LDD. These include the PF Preference (PF-02) rate, the PF Exchange Program (PF-02) rate, and the NR-02 rate.

(4) BPA has clarified the definition of "consumers" for calculating the purchaser's C/M ratio. The C/M ratio will be calculated by dividing the maximum number of consumers within the purchaser's distribution system, in any one month during the Calendar Year (CY), by the end of CY number of pole miles of distribution. This clarification eliminates confusion in counting irrigation and seasonal consumers and only counts consumers on the distribution system.

(5) BPA has clarified the data required for the determination of pole miles. Instead of determining pole miles by averaging two years of data, pole miles will be based on the end of CY pole mile count. This will reduce the time it presently takes to implement the LDD.

An explanation has been added on how the LDD will be applied to Slice purchases. *See* Wholesale Power Rate Schedules, WP-02-A-02, Appendix 1, GRSPs, Section II.Q.

2.10 Conservation and Renewables Discount (C&R Discount)

To encourage Northwest customers (utilities and DSIs) to undertake conservation projects and build renewable resources, BPA is providing a C&R Discount to PF-02, NR-02, RL-02, and IP-02 Rate Schedules. The C&R Discount is also available to eligible Purchasers of the Slice product and is included in the benefits provided as a cash payment in settlement of the REP. The cost of the C&R Discount has been included as a cost adjustment in developing rates for this rate period. *See* section 2.3, Table RDS 35 of Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A. To calculate this cost, 0.5 mills/kWh was applied to forecasted loads served by posted rates and the Slice product.

Customers' monthly bills will show the C&R Discount as a line item reduction. Individual monthly reductions will be 0.5 mills/kWh multiplied by one-twelfth of the customer's forecasted annual purchases from BPA under its Subscription contract. This forecast will be developed and agreed to by BPA and the individual customer by the signing of the individual power contract agreement. REP settlement benefits will be included as power equivalents in this calculation.

The monthly C&R Discount amount is calculated for each customer prior to the FY 2002-2006, rate period. BPA has assumed the C&R Discount will generate no net revenue during the rate period. BPA is assuming all eligible customers will participate in the C&R Discount. Participation occurs when customers pay their monthly bills at the reduced rate. As participants, customers accept responsibility to make appropriate expenditures in conservation and renewable resources during the rate period. Only expenditures that are incremental to investments customers would have made in the absence of the C&R Discount are eligible for the C&R Discount. Failure to make the appropriate expenditures will result in the customer having to reimburse BPA the difference in the amount of the C&R Discount received and the customer's actual qualifying expenditures.

BPA will establish policies setting appropriate criteria for qualifying expenditures prior to the beginning of the rate period. BPA may approve recommendations on the eligibility of specific activities provided to it by the NWPPC's Regional Technical Forum (RTF). 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 determination of future adjustments to the savings credited for measures and program designs.

Customers must submit annual interim reports documenting conservation and renewable resource qualifying expenditures for each year. In these reports, customers will identify the cumulative monetary discounts they have received to date as well as their annual and cumulative qualifying expenditures. The purpose of the report is to ensure that each customer is on track and will not be required to reimburse any portion of the discount for failure to perform.

A final report on qualifying expenditures is required at the end of the customer's discount period. The discount period is the term of the customer's contract or the FY 2002-2006 rate period, whichever is shorter. BPA will evaluate the customer's total qualifying conservation and renewable resource project expenditures during the discount period. When documented total qualifying expenditures are less than the sum of the monthly billing discounts for the discount period, customers will be required to reimburse BPA the difference.

2.11 Green Energy Premium (GEP)

The GEP is available to customers purchasing firm power under the PF-02, RL-02, NR-02, and the IP-02 rate schedules. The GEP will be charged when a customer chooses to designate any portion (up to 100 percent) of its Subscription purchase as Environmentally Preferred Power (EPP). By paying the GEP, BPA’s customers acquire the marketing flexibility associated with EPP to meet the needs of environmentally conscious retail consumers. The amount of EPP that customers may designate will be limited by the availability of EPP resources and the individual customer’s Subscription firm power purchase.

The GEP will range from 0 to $40/MWh depending on the specific resource types selected by each customer. The negotiated GEP for any specific customer will be calculated by determining the difference between the customer’s average energy cost, based on the applicable loads and rate schedules and all applicable costs associated with the EPP. Such EPP costs may include, but are not limited to, the following:

(1) Costs of existing EPP resources, over and above the cost of BPA system resources.

(2) Costs of new EPP resources, over and above the cost of BPA system resources.

(3) Costs of BPA system resources.

(4) Endorsement fees for specific EPP resources.

(5) Market purchases of EPP resources matching customer specifications.

(6) Transmission and other services required to integrate EPP resources into the BPA system.

BPA currently forecasts no revenue from the sale of EPP under the GEP. To the extent incremental GEP revenue is received, it will not change BPA's revenue requirements. If the output of non-BPA resources is acquired to meet GEP requests, the GEP will include all associated incremental costs. Excess revenue generated by the GEP will benefit BPA's customers at large.

Given sufficient customer interest, BPA will make up to 200 aMWs of power available for GEP purchases.

2.12 Targeted Adjustment Charge (TAC)

BPA has established a window for the negotiation and execution of Subscription power sales contracts from February 1999, until 120 days after the ROD for BPA's 2002 Power rate case is signed. After the window closes, all customer requests for requirements service under the PF Preference (PF-02) and NR-02 rate schedules, except the PF Exchange Program rate and the PF Exchange Subscription rate, will be subject to the TAC. This includes customers that execute contracts late, new publics and annexed load, or retail access load gain or returning load. The TAC will not apply to amounts of power purchased under a customer's initial Subscription contract.

TAC will also apply to subsequent requests made by a customer under a Subscription contract for requirements service for such customer's load(s) 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. The TAC will also apply to purchases under the NR rate.

BPA may exempt newly acquired load from the TAC and apply the PF-02 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 will apply if the annexed requirements service has been previously served by the customer's 5(b)(1)(A) or 5(b)(1)(B) resources.

Where a public agency customer annexes residential and small farm load previously served by an IOU and such load was receiving BPA power or financial benefits through Subscription, the public agency customer will receive, by assignment through BPA, the right to the IOUs power and/or financial benefits applicable to the annexed load. BPA will deliver an amount of firm power to the annexing public agency customer at the PF-02 rate equal to the amount of benefits (power and/or financial) assigned by the IOU to BPA. Power provided by BPA to the public agency customer to meet the remaining annexed load not covered by the benefits assigned from the IOU will be subject to the TAC.

The TAC will apply for the duration of the customer's contract or until 2006, whichever occurs first. For five-year contracts that guarantee rates for multiple periods (for example, contracts that have both three- and five-year components) the TAC applies until the end of the five-year rate period. If a new public requests service, the TAC will apply until 2006.

While BPA has forecast that no loads will be served under the TAC, BPA is including a TAC in order to recover the cost of power purchases that BPA must undertake, if any, to serve unexpected incremental load. The TAC is intended to recover the costs BPA incurs that are not included in BPA's power revenue requirement for the FY 2002-2006 rate period. If the cost of power to serve these loads is above BPA's embedded costs, BPA's financial reserves may be impacted. The TAC will prevent the erosion of reserves that could occur from additional costs to meet unanticipated increases in load.

The TAC is defined as the charge that shall apply to the incremental power acquired by BPA needed to meet the subject loads. The TAC will be calculated for an individual customer's request and shall be determined in the following manner. BPA will determine the amount of power available to serve incremental requests based on average annual Federal system capability at critical water, excluding balancing purchases and purchases for System Augmentation as defined in the 2002 rate case, with updates to the Loads and Resources Study Documentation, WP-02-FS-BPA-01A, if BPA determines that is necessary.

If sufficient power to serve the incremental load is available, such power shall be sold at the PF-02 rate, or the NR-02 rate. In the event power is not available and BPA must acquire additional power to meet the load, such additional power shall be sold at the PF-02 rate, or the NR-02 rate, plus an adjustment charge reflecting the difference between the PF-02 rate, or NR-02 rate, and BPA's monthly cost to supply this power.

BPA will calculate the cost per month in mills/kWh of the additional power per month for a specific customer request based on BPA's monthly cost to purchase resources, at market plus a handling fee, to serve the incremental load. These costs may include, where applicable, wheeling, ancillary, and other charges BPA may incur in purchasing power from other entities such as, but no limited to, the California ISO or the CalPX.

The adjustment will not reduce the total price for power below the PF-02 rate, or the NR-02 rate. The TAC will be applied to the monthly HLH and LLH energy rates for the applicable month or months as specified in the 2002 rate schedules.

BPA will calculate the cost for the TAC at the time a customer requests power under this schedule. The TAC will be finalized prior to signing of the final contract or before initial delivery.

In order to encourage renewable development in the region, BPA will 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: (1) a certifiable renewable resource eligible for the C&R Discount; or (2) contract purchases of certified renewable resource power eligible for the C&R Discount, for a period less than the term of the customer's BPA requirements firm power contract, then the customer may request requirements firm power service during the FY 2002 to 2006 rate period for such load at the end of the specified contract period at the PF-02 rate without being subject to the TAC. This limited exception applies only to the first 200 aMWs in any contract year or to amounts and types of resources that BPA specifies in accordance with its final policy on the Determination of Net Requirements.

2.13 Industrial Firm Power Targeted Adjustment Charge (IPTAC)

The IPTAC applies to all purchasers under the IP rate schedule.

BPA has established two IPTACs. For DSI customers that will be paying IPTAC(A) and to whom BPA will offer a total of 1,210 aMWs of power, the sum of the IP-02 rate, plus their IPTAC has been calculated in the RAM to equal 23.5 mills/kWh. For DSI customers that will be paying IPTAC(B) and to whom BPA will offer a total of 230 aMWs of power, the sum of the IP-02 rate plus their TAC has been calculated in the RAM to equal 25.0 mills/kWh. The customers to whom BPA is offering the lower IPTAC(A) have told BPA they can support the offering of power at 23.5 mills/kWh. Other DSI customers have indicated that they cannot support BPA offering them power at 23.5 mills. There is a higher risk that this latter group of customers would not buy the power from BPA or would do so only under market conditions that make it more expensive for BPA to purchase energy to serve their load. BPA is not willing to propose that other BPA customers support the level of costs and risks associated with making an offer to DSIs that cannot support BPA's proposed sales. Therefore, for that group of DSIs, BPA is proposing a IPTAC(B), which is higher than the IPTAC(A).

The rates models have calculated a Subscription Step IP-02 rate at the DSI Floor, 20.98 mills for undelivered flat power. To this base rate, 0.5 mills is added to cover the costs of the C&R Discount. Two TACs of 2.02 mills (IPTAC(A)) and 3.52 mills (IPTAC(B)) are used to yield overall rates of 23.5 mills/kWh and 25.0 mills/kWh, respectively.

These rates are designed to recover the cost of serving the DSI load and to keep BPA whole, and are not designed to discourage purchases from BPA.

2.14 Flexible IP Rate

The Flexible IP rate option will be offered at BPA's discretion to customers who make a contractual commitment to purchase power from BPA at the IPTAC(A) and IPTAC(B). If the customer elects to use a Flexible IP rate and BPA agrees, then the Flexible IP rate option will apply to the entire five-year rate period or any remaining portion of the rate period. The general concept of the Flexible IP rate option is that a DSI customer may be able to shape their monthly and/or annual power costs to best meet their financial needs. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a customer under this option. The actual charges and billing factors will be mutually agreed to by BPA and the customer. The following criteria will be used in establishing any flexible rate.

(1) Equivalent Net Present Value Revenues: Forecasted revenues from a customer utilizing the Flexible IP rate option must be equivalent to or greater than, on a net present value basis, the revenues, including those from the IPTAC(A) or IPTAC(B), BPA would have received from the customer.

(2) Risk Adjustments: Credit risks associated with individual customers will be a factor in establishing any Flexible IP rate option. Creditworthiness will be determined by BPA consistent with prevailing business standards, and applied consistently to each customer. Such credit risks will be dealt with through a "margin deposit," an expense charge, built into the rates, or other methods acceptable to BPA.

2.15 Slice of the System (Slice) Product

BPA is offering the Slice requirements power product. The Slice is a sale of a fixed percentage of the generation capability of the Federal Columbia River Power System (FCRPS) and is not a sale or lease of any part of the ownership of, or operational rights to, the FCRPS. The amount of Slice available to a purchaser is based upon a Slice purchaser's annual net firm requirements load. However, the sale is shaped to BPA's generation from the FCRPS, rather than to the Slice purchaser's load. The purchase of the Slice product will require a commitment by the Slice purchaser of 10 years.

Because the Slice product is calculated as a percentage of the FCRPS, the actual MW delivered to the Slice purchaser will vary throughout the year. During certain periods of the year and under certain water conditions, the power delivered will exceed the Slice purchaser's net firm requirements and may at times exceed the Slice purchaser's actual firm load. As a consequence, the Slice product entails a sale of both requirements and surplus power products.

Slice purchasers will assume the obligation to pay a percentage of BPA's costs, rather than pay a set price per MW and MWh. The Slice purchaser's obligation to pay is equal to the percentage of the FCRPS that the Slice purchaser elects to purchase. The costs to be covered by Slice purchasers are referred to collectively as the Slice Revenue Requirement. The Slice Revenue Requirement is comprised of all of the line items in BPA's power revenue requirement identified in the 2002 Power rate case, with certain limited exceptions (*see* Slice Product Costing and True-Up Table on Attachment 1 in Appendix C in the Wholesale Power Rate Development Study, WP-02-FS-BPA-05, for a detailed list of the line items in the Slice Revenue Requirement). Because Slice purchasers will pay a percentage of BPA's costs, regardless of weather, streamflow, market, or generation output conditions, this assured payment will mitigate BPA's financial risks in the event that any of these conditions put adverse financial pressure on BPA. Conversely, the assured payment would dampen BPA's financial gain when these conditions would otherwise be beneficial to BPA.

It is possible that during the term of the Slice contract, BPA may take steps to increase or supplement the capability of the FCRPS to serve BPA's requirements customers. This supplementing or augmenting of the capability of the FCRPS to serve requirements customers is referred to as the "Inventory Solution." The costs, net of revenues, associated with the Inventory Solution will become an obligation of the Slice purchasers. Even though the Slice purchaser will be responsible for a proportionate share (based on the Slice purchaser's selected Slice percentage) of the net costs associated with supplementing the system, the Slice purchaser will not receive any portion of the power supplement.

The Slice product was designed to eliminate cost shifts between Slice purchasers and non-Slice customers. Because Slice purchasers will pay a proportionate share of all costs of BPA's system attributable to the sale of the Slice product, and those are costs that are shared with non-Slice customers, there should be no cost shifts to non-Slice customers. Also, since Slice purchasers will avoid paying the costs of risk mitigation for only those risks that Slice purchasers assume directly, there should be no shifting of risks or costs from Slice purchasers to purchasers of other Subscription products. BPA has performed a Cost Shift Study to evaluate the effectiveness of the product design at eliminating cost shifts under varying water and market conditions and under varying percentages of the Federal system generation output sold as Slice products. This study is documented in Appendix C of the Wholesale Power Rate Development Study, WP-02-FS-BPA-05.

2.16 Proposed Residential Exchange Settlement

The REP will continue to exist during the rate period; however, BPA's Subscription Strategy proposes a settlement of the Program for regional IOUs. The proposed settlement includes a power sale and a financial component. Because BPA does not know whether eligible utilities will continue participation in the REP or agree to a settlement of the Program, BPA must establish rates to govern both possibilities. The PF-02 Exchange Program rate applies to the continued implementation of the REP. The PF-02 Exchange Program rate is calculated in the Rate Design Step section of the RAM. *See* section 3.3.7 below. The PF-02 Exchange Subscription rate and the RL-02 rate apply to IOU sales under the proposed Residential Exchange Settlements. *See* section 3.4 below.

2.17 Allocation of Subscription Credits and Costs

The Subscription Strategy expected that posted rates for all Subscription power sales would be approximately equal, subject to BPA's statutory rate directives and establishment in a section 7(i) hearing. That is, the Strategy expected that customers purchasing power under the PF Preference (PF-02) rate, the PF-02 Exchange Subscription rate, the IP-02 rate, or the RL-02 rate would all be facing approximately the same cost of power. The Subscription Step in RAM equitably allocates Subscription-related credits and costs to the foregoing firm power rate schedules, resulting in equal PF Preference (PF-02), PF-02 Exchange Subscription, and RL-02 posted rates. The IP-02 posted rate is slightly higher because it includes the addition of the DSI net margin and is restricted to being at or above the DSI Floor rate. In addition, DSIs purchase power at the IP-02 rate plus an IPTAC, to recover the costs of purchases to meet additional DSI load.

2.18 Cost-Based Indexed IP Rate

The Cost-Based Indexed IP Rate option (indexed rate) described below is available to DSI smelter operations. An indexed rate will also be made available, at BPA's discretion, to non-aluminum smelter DSIs where an appropriate index is available on which to base an indexed rate. The Cost-Based Indexed IP Rate for smelter operations is a rate in which the price of power is linked to aluminum prices as measured by the London Metal Exchange (LME) for their three-month aluminum contract denominated in U.S. dollars. The indexed rate being proposed is similar to the variable IP rates that BPA adopted in past rate cases. The indexed rate has been designed around rate and aluminum price parameters so that, on a projected basis, BPA will recover revenues equivalent to revenues it would recover under the IPTAC rates. As designed, the indexed rate will have both a maximum (upper rate limit) and minimum (lower rate limit) power rate. The proposed upper rate limit is 28.50 mills/kWh and will be in force whenever the monthly price of aluminum is calculated to be at or above the corresponding aluminum price cap (upper pivot point). The proposed lower rate limit is 19.0 mills/kWh and will be in force whenever the monthly price of aluminum is calculated to be at or below the corresponding aluminum price floor (lower pivot point). The relationship between the power rate and aluminum prices shall be predicated upon the ratesetting mechanism. Such mechanism will be established at the time the power sales contract is signed, or within 90 days thereafter. As such, the power rate will be set based on the prevailing market price for aluminum at the time the rate is taken (0 to 90 days after execution of the power sales contract), plus up to a 2 cent/lb. Aluminum price risk premium. Further, the rate at which aluminum prices are tied to power ($28.50/MWh maximum and $19.00/MWh minimum) shall be within a range of 66 to 72 cents/lb., (68/lb., and 74/lb. with the maximum 2 cent risk premium) based on the market price quotes of LME equivalent prices. BPA will use such transactable quotes as the basis to hedge away its aluminum price risk from this rate (inclusive of the risk premium). Further detail of the rate and its parameters is contained in the example below.

IP Cost–Based Index Rate Example
(based on a 69.6 cent market price and full 2 cent risk premium)

	Cents/Lb.	$/MWh
Rate Mid (@ Market 69.6)	**0.716**	**23.5**
Cap - Aluminum /Power Prices	**0.776**	**28.5**
Floor - Aluminum Power Prices	**0.656**	**19.0**
Lower Slope Decrements	**0.01**	**0.750**
Upper Slope Increments	**0.01**	**0.833**
Range - Aluminum / Power Prices	**12.000**	**9.500**

Note: the range of possible midpoints under this rate are a maximum of 74 cents/lb. and a minimum of 68 cents per pound. The midpoint shall be set based on an evaluation of market price quotes, plus an appropriate risk premium of up to 2 cents/lb.

The indexed rate will be billed on a monthly basis, corresponding to changes in the average daily closing prices of the LME three-month futures contract. Such prices will be based on the entire calendar month's daily closing prices (monthly average).

2.19 Cost-Based Indexed PF Rate

The Cost-Based Indexed PF Rate will be offered to all firm load requirements customers who wish to convert their applicable PF rate under their contracts to a market-indexed or floating price adjusted for BPA's risk. The following are features of this rate:

(1) BPA and the customer will choose during contract negotiations a mutually agreed reference point and sponsor for the index used. For example, the California-Oregon Border (COB) (location) and the DJ cash or the New York Mercantile Exchange (NYMEX) futures (sponsor), or some other combination to arrive at an agreed upon index.

(2) BPA will base the index pricing on a current market forecast of the market index referenced. The expected Net Present Value (NPV) revenue of the forecast index prices will be adjusted by a HLH and a LLH Market Index Monthly Adjustment (MIMA) to equal the expected NPV of the applicable PF rates. The MIMA reflects BPA's PF equivalent expected revenues at the time the contract is signed, including an insurance premium to ensure revenue sufficiency.

(3) Customers must select this rate for the term of their Subscription contract that the 2002-2006 rate period covers. Customers who choose a contract length of less than five years and wish to renew will be subject to rates established under a new rate case.

(4) Billing will be based on the index's average of the last 15 days of closing or posted daily prices at the reference point. The MIMA will be calculated as follows:

Index	=	average of last 15 days of closing or posted daily prices at the reference point.
PF	=	monthly PF HLH or LLH energy rate.
Cost of Insurance	=	The premium on a physical and financial instrument used to mitigate the risk.
MIMA	=	Index – PF + Cost of Insurance

2.20 Rate Melding

BPA's final rate proposal allows the customers more than one rate choice. Separately tracking and administering the customer's rate choices and maintaining the distinction would increase BPA's overall cost of providing rate choices. For administrative simplicity upon mutual agreement between BPA and the customer, BPA may offer to meld the customer's rate choices into a single composite set of rates that reflects the specific choices made by the customer. BPA will ensure that this melded set of rates will result in a bill that is nearly mathematically equivalent to applying the customer's individual choices throughout the rate period. BPA will provide the affected customer the calculations it used to establish the melded rates and provide 30 days for the customer to review and accept the melding calculation before it implements the melded rates. Melded rates established by BPA will continue until one of the customer's rate choices expires, or a rate adjustment occurs that is provided for under the chosen rate schedules (*e.g.,* Cost Recovery Adjustment Clause), or a significant change in the loads applicable to the rates occurs.

3. COST ALLOCATION AND RATE DESIGN IMPLEMENTATION

3.1. Ratemaking Sequence

The ratemaking methodology in the Wholesale Power Rate Development Study includes a COSA, a series of Rate Design Step adjustments, and a Subscription Strategy section. The COSA assigns responsibility for BPA's 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 in the COSA are necessary to assure that BPA recovers its test period costs and to implement various policy objectives. The Subscription Strategy section takes the rates resulting from the Rate Design Step and makes adjustments to reflect BPA's Subscription Strategy objectives.

3.2. Cost of Service Analysis (COSA)

The COSA allocates the test period generation revenue requirements that are determined in the Revenue Requirement Study, WP-02-FS-BPA-02, to BPA's customer classes. The COSA apportions or "allocates" the test period generation revenue requirements among classes of service based on the principle of cost causation. The relative use of resources, services, or facilities among customer classes is identified, and costs generally are allocated to customer classes in proportion to each class's use. Cost allocation also is based on the priorities of service from resource pools to rate pools provided in section 7 of the Northwest Power Act.

Four major ratemaking steps were completed in the process of determining BPA's total cost of service: (1) *functionalization* of costs between generation and transmission; (2) *segmentation* of costs of BPA's transmission system; (3) *classification* of costs between demand, energy, and load variance; and (4) *allocation* of costs to classes of service.

In this power rate case, BPA is determining power rates to be charged by BPA's Power Business Line (PBL). Functionalization of costs between generation and transmission was performed in conjunction with the development of BPA's total revenue requirements and only those costs associated with the PBL are included in BPA's final rate proposal. The segmentation of BPA's transmission system costs will be performed as part of BPA's TBL rate proceeding. The remaining steps to determine BPA's cost of service for wholesale power--classification and allocation of costs--are performed in the COSA portion of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A, section 2.2.

3.2.1 PBL 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 cost 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.

The 2002 Revenue Requirement Study, WP-02-FS-BPA-02 is based on revenue and cost estimates for a five-year test period, FY 2002 through 2006. The generation revenue requirements from the Revenue Requirement Study are adjusted in the Wholesale Power Rate Development Study COSA for projected balancing purchase power costs, system augmentation costs, the functionalization and classification of REP costs, and for REP cost differences resulting from the difference between estimated and proposed rates. *See* section 3.2.1.1 below. For the five test years, the total adjusted generation revenue requirement is $12.560 billion. Adjusted annual functionalized revenue requirements used for rate calculations are shown in the section 2.2, Tables COSA 06 FY 02 through COSA 06 FY 06 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A. Total adjusted functionalized revenue requirements for the five-year period are shown in section 2.2, Table COSA 08 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.1.1 Functionalized Revenue Requirement. In compliance with a Federal Energy Regulatory Commission (FERC) order dated January 27, 1984, *U.S. Department of Energy--Bonneville Power Admin.*, 26 F.E.R.C. ¶ 61,096 (1984), and due to BPA's policy of voluntarily separating the generation and transmission activities of BPA (*see* Metcalf and Cherry, WP-02-E-BPA-10), BPA is proposing a bifurcated rate case. PBL power rates will be set to recover only generation costs and transmission costs associated with PBL marketing activities. Transmission rates will be set in a separate rate case. BPA has determined a separate revenue requirement for the generation component of the FCRPS. Accordingly, BPA has prepared a separate power repayment study for the generation functions. All costs to be recovered through FCRPS power rates are functionalized to generation to develop the revenue requirements used in this rate proposal.

The Revenue Requirement Study, WP-02-FS-BPA-02, also includes separate demonstrations for generation to show that proposed revenues are adequate to recover all generation 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 shown 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 less the costs associated with the Idaho Falls and Cowlitz projects. Costs of purchased power from contracts from the early 1990s are included in the NR resource pool. *See* section 2.2, Tables COSA 06 for FY 2002 through FY 2006 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.1.2.2 Balancing Power Purchases. Included in the costs of balancing power purchases are the costs of power purchases and storage required to meet firm deficits on a daily and monthly basis. Projected balancing power purchases are needed to serve firm loads at the margin in months other than the spring fish migration period. The expense estimate for balancing power purchases included in the revenue requirements is adjusted in the COSA as a result of Risk Analysis Model (RiskMod) modeling to reflect projected operation of the FCRPS. *See* section 3.4 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A. Costs of balancing power purchases are characterized as FBS replacements and as such are included in and allocated as FBS costs. *See* section 2.2, Tables COSA 06 for FY 2002 through 2006 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.1.2.3 System Augmentation. BPA is also proposing to acquire resources beyond the inventory represented by the FBS generating resources. These acquisitions are defined as system augmentation costs in the COSA and are used to meet customer firm power loads in excess of firm FBS resources on an annual basis. System augmentation purchases are characterized as FBS replacements. The Federal system will be augmented using both long- and short-term power purchase contracts. System augmentation costs are shown in section 2.2, Tables COSA 06 and COSA 08 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.1.3 Adjustments to Gross Residential Exchange Costs. BPA's revenue requirement includes the gross cost of the REP, which is affected by the proposed PF rate. In the beginning of the rate development process, REP costs are projected using an estimate of the PF rate for the test period. These costs are included in the functionalized revenue requirements. If the proposed PF rate differs from the estimated rate, the REP cost is recalculated. The PF rate is then recalculated based on the revised REP costs. This iterative process stops when the PF rate does not change from the previous iteration. This adjustment of the gross REP costs is necessary because the PF rate level influences the level of the Residential Exchange costs included in the COSA. *See* section 2.2, Tables COSA 06 for FY 2002 through 2006 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.2 Functionalization and Classification of Residential Exchange Program Costs. In the COSA, the gross REP cost is based on exchanging utilities' ASC and the amount of their exchangeable loads. ASC include the cost of power, transmission, and unbundled services associated with serving the exchanging utility's exchangeable load. The rate design adjustments that follow the COSA in the Wholesale Power Rate Development Study, and use the results of the COSA performed on that portion of the revenue requirement classified to energy. Consequently, the REP cost that comes into the COSA with energy costs, demand costs, transmission costs, and unbundled services costs included, must be functionalized to generation and then classified to energy. In this way, REP costs are made to comport with all other PBL costs as they go through the rate design adjustment process. The functionalization and classification of REP costs are shown in section 2.2, Table COSA 07 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.3 Classification. Classification in the Wholesale Power Rate Development Study apportions generation costs between the demand, energy, and load variance components of electric power. This classification of the generation revenue requirement is shown in section 2.2, Table COSA 08 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

The classification methodology BPA uses is based on the marginal costs of the components of power and generally accepted ratemaking procedures. BPA sets the price for demand using an adjusted marginal cost of demand. *See* section 2.3.1.2 above for a detailed description.
In addition, BPA sets the price of the Load Variance Charge using its adjusted marginal costs. *See* section 2.3.4.1 above, for a detailed description. Sales and revenues of these products are then forecasted. Forecasted revenues associated with demand are classified to demand. Forecasted revenues for load variance are deemed to be equal to the cost of Load Variance and therefore classified as such. Generation costs classified to energy are the residual of total generation costs not classified to demand or load variance. By virtue of this classification scheme, costs of demand, or load variance are not directly allocated to customer rate pools; rather, the costs are equal to the forecasted revenues. The only allocation of costs to customer rate pools in the COSA is for costs associated with energy.

3.2.4 Functionalized and Classified Revenue Credits. The revenue credits described below are functionalized to generation and classified to energy. 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 BPA's power rates.

3.2.4.1 U.S Army Corps of Engineers (COE) and Bureau of Reclamation (Reclamation) Project Revenues. COE and Reclamation Project revenues are payments from owners of downstream projects to the COE and Reclamation for benefits received (*i.e.*, additional generation) from the storage reservoirs owned by the COE and Reclamation. These revenues are not subject to revision through rates and hence are a revenue credit. *See* section 2.2, Table COSA 09 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.4.2 Section 4(h)(10)(c) Credits and Fish Cost Contingency Fund (FCCF). Section 4(h)(10)(c) credits are provided by the Treasury to partially compensate BPA for additional capital and operational costs that are incurred for fish migration. These credits are 27 percent of BPA's additional expenditures. This revenue is an estimate of what BPA would receive on average over a range of 50 different water conditions. The actual credit is determined after the year is completed. The operational costs vary with water conditions. The FCCF credit is similar to the 4(h)(10)(c) credit since it is provided by the Treasury. The amount included here is an estimate based on the average of 50 water years. Only under the 15 worst water years would any credit be received, and then it would be much larger. The FCCF credit is limited by past expenditures BPA made for fish operations without receiving Treasury credits. The FCCF credit pool totals about $325 million. In an extremely bad water year, this amount could be accessed in order to avoid missing Treasury payments. *See* section 2.2, Table COSA 09 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.4.3 Colville Credit. The Colville credit is a credit BPA receives for being an agent of the U.S. Government and facilitating annual payments to the Colville Tribe as a result of a treaty settlement. The credit is equal to the amount BPA pays the Tribe and it is essentially a predetermined amount. *See* section 2.2, Table COSA 09 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.4.4 Supplemental and Entitlement Capacity. BPA receives Supplemental and Entitlement Capacity revenues from private and public utilities as a result of contracts signed many years ago where the rates are fixed at a nominal amount per year. The revenue is a predetermined amount. *See* section 2.2, Table COSA 09 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.4.5 Irrigation Pump Revenues. BPA receives a small amount of income from the delivery of pumping power at very low rates to Reclamation irrigation projects. While this revenue is not fixed, it totals less than $500,000 per year, depending upon the weather. This revenue is paid at the end of the year to the Treasury by the Reclamation. *See* section 2.2, Table COSA 09 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.4.6 Energy Services Business Revenues. BPA receives revenues associated with the activities of its Energy Services Business. *See* Section 2.2, Table COSA 09 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.4.7 Property Transfers and Miscellaneous Revenues. Most of these estimated revenues are from contract administration, late fees, interest on late payments, and mitigation payments. These fees are not subject to change in the rate filing. *See* section 2.2, Table COSA 09 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.5 PBL Transmission Costs, Revenues, and Credits. The PBL, in the course of marketing power, incurs transmission-related costs and generates transmission-related revenues and credits. The costs include, but are not limited to, those associated with providing ancillary and reserve services and General Transfer Agreements (GTA). The revenues and credits are predominantly revenues associated with providing ancillary and reserve services. The net amount of these costs, revenues, and credits is classified to energy, and has the effect of reducing the FBS resource costs to be recovered by BPA's power rates. *See* section 2.2, Table COSA 10 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.6 Allocation. Allocation is the apportionment of costs to 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. Rate pools are groupings of customer classes (sales) for cost allocation purposes. BPA groups its sales into the "Priority Firm," "Industrial Firm," and "All Other" categories corresponding to sections 7(b), 7(c), and 7(f) of the Northwest Power Act. The resource pools are those identified in the Northwest Power Act as the FBS, Residential Exchange, and NR 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 from planning load and resource balances prepared in the Loads and Resources Study, WP-02-FS-BPA-01.

The Northwest Power Act establishes three rate pools. The 7(b) rate pool includes public body, cooperative, and Federal agency sales as well as the 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. The 7(f) rate pool includes all other power BPA sells in the PNW. 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.

For BPA's final 2002 power rate proposal, the FBS resource pool consists of: (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 resources. Costs expected to be incurred during the rate period for replacement resources were included in the FBS resource pool. *See* Loads and Resources Study, WP-02-FS-BPA-01, Appendix B. In addition to long-term resource acquisitions, short-term power purchases are made during the rate period. These short-term power purchases augment the Federal system to achieve load/resource balance on an annual basis as well as balance the Federal system to provide operational flexibility and provide for certain fish mitigation measures on a monthly and daily basis. The costs of such balancing purchases as well as the cost of system augmentation to ensure load/resource balance are considered to be FBS costs and are allocated as such.

3.2.6.1 Energy Cost Allocations. The process for allocating energy costs begins with an examination of critical period firm loads and resources to determine the amount of monthly firm energy surplus or deficit. A ratemaking load and resource balance for each month of the test period is then constructed from the Loads and Resources Study, WP-02-FS-BPA-01, and other data. From this ratemaking load and resource balance, service to each of the three rate pools from each of the resource pools is determined for the rate test period. Table EAF05 shows the ratemaking energy loads and resources by pools. *See* section 2.1, Table EAF05 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A. Allocation factors, which apportion each resource pool's costs to BPA's classes of service, are calculated based on identified service from resource pools to rate pools in the ratemaking load and resource balances.

3.2.6.2 Energy Allocation Factors. When service from each resource pool to each class of service has been identified, the amount of such service is the allocation factor for 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 section 2.1, Table EAF05 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A. The Total Usage and Conservation allocation factors are the same and are based on the sum of the FBS, REP, and NR allocation factors. They are used to allocate costs and rate design adjustments to all firm energy loads. Allocated energy costs are shown in sections 2.2 and 2.3, Tables COSA 11 and RDS 01 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.6.3 Other Cost Allocations. Costs not directly identifiable with rate pools, resource pools, or transmission costs allocated to PBL are allocated as described below.

3.2.6.3.1 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. The "legacy conservation" line item, as seen in the COSA 06 tables (*see* section 2.2 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A), includes: (1) debt service for BPA's previous resource acquisition activities; (2) BPA's continuing contributions to the region's market transformation efforts; and (3) a share of the agency's total planned net revenues. The "conservation augmentation" line item, as seen in the COSA 06 tables (*see* section 2.2 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A) includes costs associated with forecasted conservation for the FY 2002 through 2006 time period. In addition, the Northwest Power Act indicates that BPA should encourage the development of conservation and renewable resources in the region. Toward that end, the "energy efficiency" expenses line item, as seen in the COSA 06 tables (*see* section 2.2 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A), reflects BPA's costs associated with providing conservation and renewable resources information in the region. In addition, these costs represent the technical support BPA provides in the region in the area of energy efficiency. The "energy efficiency" revenue line item seen in Table COSA 09 (*see* section 2.2 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A), reflects payments provided by other BPA organizations and Federal agencies for the energy efficiency services delivered.

3.2.6.3.2 BPA Program Costs. Some of BPA's program costs are not directly identified with any specific resource pool, or customer class. An example is the cost of the ratemaking process. The generation portion of these costs is determined in the Revenue Requirement Study, WP-02-FS-BPA-02. The generation portion appears as BPA program costs. These costs, as seen in COSA 11 Table (*see* section 2.2 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A), are allocated uniformly to all customer classes based on the total usage allocation factors for energy.

3.2.6.3.3 WNP-3 Settlement Exchange Agreement Costs. The revenue requirement includes costs related to the WNP-3 Settlement Exchange Agreement between BPA and four IOUs that have a 30 percent interest in the WNP-3 nuclear plant. Two types of WNP-3 Settlement Exchange costs are allocated in the COSA: plant-related costs and exchange energy costs. Under the WNP-3 Settlement Agreement, BPA is obligated to serve a specified amount of IOU load. Whether BPA must purchase to serve WNP-3 obligations is determined in RiskMod. To serve the IOU load, BPA may purchase either Company Exchange Energy from the IOUs or other, lower-cost power. The exchange energy costs are the projected costs of purchases of Company Exchange Energy (which may not exceed the costs of combustion turbines) or other purchases and storage in lieu of Company Exchange Energy. These costs are allocated uniformly to all loads using the total usage allocation factors for energy. *See* section 2.3,

Table RDS 01 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.2.6.3.4 Planned Net Revenues for Risk (PNRR). PNRR is the amount of net revenues required to ensure that cash-flow from proposed rates fully meets BPA's probability standard for repaying Treasury on time and in full. The PNRR are functionalized entirely to generation and are allocated to resource pools that include Federal capital investments. The methodology is described and illustrated in the Revenue Requirement Study, WP-02-FS-BPA-02.

The PNRR value found in the COSA 06 tables is the result of an iterative process between the RAM, the RiskMod, Non-Operating Risk Model (NORM) and the ToolKit models. The iteration is initiated with a seed value for PNRR in COSA 06 of the RAM. 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 and ending cash reserve amounts for new COSA 06 tables. *See* Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A. For a further explanation of this iterative process *see* Doubleday *et al.*, WP-02-E-BPA-18.

3.2.7 COSA Results. The result of the COSA process is the allocation of the test period revenue requirements for energy to classes of service served with firm power. Tables COSA 11 and RDS 01 summarize the allocated generation energy revenue requirements and the total allocated revenue requirement recoverable from power rate classes of service, including transmission costs allocated to the PBL, that are recoverable from these classes of service. *See* section 2.2, Tables COSA 11 and section 2.3, RDS 01 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.3 Rate Design Step Adjustments

Rate design adjustments are performed sequentially in the order described below.

3.3.1 Excess Revenue Adjustment. The Excess Revenue Adjustment recognizes that revenues will be collected from certain classes of service to which costs are not allocated and credits these revenues to other customer classes. The source of excess revenues is projected nonfirm energy sales.

3.3.1.1 Secondary Energy Sales. On a planning basis and with system augmentation, BPA will have firm resources available to meet firm load obligations under 1937 water conditions. However, rates are set assuming that better than critical water conditions occur and, therefore, secondary energy sales and revenues are projected. These sales and revenues are projected on the 50 water year run of the RiskMod model. *See* Conger *et al.*, WP-02-E-BPA-15. The projected secondary energy revenue credits are allocated to firm loads so that BPA does not recover more than its revenue requirements. In previous rate cases, secondary energy revenue was referred to as "nonfirm" energy revenue.

The RiskMod model is used to project the level of secondary energy sales and revenues. BPA expects to sell secondary energy that will produce $2.578 billion in revenues over the five-year test period. After reducing these revenues by transmission charges totaling $348.7 million, BPA credits its firm power customers with excess revenues totaling $2.229 billion over the five-year test period. *See* section 2.3, Table RDS 11 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.3.1.2 Allocation of Excess Revenues. Secondary energy revenues are used first to pay transmission costs associated with sales of secondary energy, with the remainder credited to firm power customers. These excess revenues are functionalized to generation and classified to energy. They are then allocated to loads served with Federal system resources (FBS and NR). The generation-related excess revenues are allocated in this manner because they are associated with secondary energy service and the cost of secondary energy is based on Federal resource costs only. *See* section 2.3, Table RDS 12 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

The Nonfirm Energy (NF) Standard rate is based on the average cost of nonfirm energy. Table RDS 05 shows the calculation of the average cost of nonfirm energy. *See* section 2.3, Table RDS 05 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.3.2 Firm Power Revenue Deficiencies Adjustment. BPA sells firm power at contractual rates and in the open market under the FPS-96 rate schedule. Sales of such firm power are not necessarily made at the fully allocated costs 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 firm power and the revenues received from the sale of such power. BPA has determined that in the FY 2002 to 2006 period it will receive $3.182 billion in revenues from the sale of firm power in various PNW and Southwest markets. Based on these sales estimates, transmission costs are estimated to be $260.4 million. *See* section 2.3, Table RDS 11 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A. BPA has allocated $3.096 billion in generation costs to the firm power sold. Therefore, there will be a revenue deficiency of $174.6 million over the five-year test period. This revenue deficiency of allocated costs in excess of revenues is charged to all firm power (PF, IP, NR) customers. *See* section 2.3, Tables RDS 17 and RDS 18 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.3.3 7(c)(2) Adjustment. DSI rates are 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 DSI rates 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 DSI rates are to be based on BPA's "applicable wholesale rates" to its preference customers and the "typical margins" included by those customers in their retail industrial rates. Section 7(c)(3) provides that the DSI rates are also 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. To more accurately reflect the product the PBL may purchase from the DSI customers, the name has been changed to Supplemental Contingency Reserve Adjustment (SCRA). However, for this rate case, BPA is not proposing a uniform SCRA credit to be applied against DSI rates. Please refer to Appendix B below. Thus, the DSI rates are set equal to the applicable wholesale rate, plus a typical margin, subject to the DSI floor rate test and the outcome of the section 7(b)(2) rate test. *See* section 3.3.4 below.

The applicable wholesale rate is the PF rate (in combination with the NR rate if new NLSLs were projected for the test period) at the DSI load factor. The typical margin is based on the overhead costs that preference customers add to BPA's price of power in setting their retail industrial rates.

The methods and calculations used to determine the typical margin are discussed in detail in Appendix A. *See* Appendix A below.

The net margin is 0.42 mills per kWh. As stated above, a zero SCRA credit is being forecast in this rate case. This net margin is added to the seasonal and diurnal PF energy charges. These adjusted PF energy charges and the charge for demand are applied to the DSI test period billing determinants to determine the initial IP rate. *See* section 2.3, Table RDS 20 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

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. Because the allocation of the 7(c)(2) delta changes the PF rate upon which the IP rate is based, the entire process is repeated with the revised PF rate from the previous iteration until the size of the 7(c)(2) delta does not change when a successive iteration is performed. This process is accomplished through an algebraic solution that is shown in Table RDS 21. *See* section 2.3 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

The size of the 7(c)(2) delta for the five-year test period is $279.8 million. This amount is allocated to PF and NR loads. The allocation is based on the energy allocation factors developed in the COSA. *See* section 2.3, Table RDS 22 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.3.4 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. 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 other purchasers of firm power. In order to make these cost adjustments, the PF rate is bifurcated. The two resulting rates are the PF Preference rate and PF Exchange Program rate.

The Section 7(b)(2) Rate Test Study, WP-02-FS-BPA-06, indicates the 7(b)(2) rate test has triggered and the PF rate applicable to BPA's preference customers must be adjusted down. The amount of protection needed is implemented through a reduction of the PF Preference rate in mills/kWh. BPA makes three adjustments in the rate design sequence to provide this protection to its preference customers and allocate the costs of the rate protection.

First, the PF Preference customer class is given a credit, which reduces its rate, by the amount of the protection indicated in the Section 7(b)(2) Rate Test Study, WP-02-FS-BPA-06. The 3.4 mills/kWh protection amount results in a credit of $646.7 million to these customers. The cost of providing this protection is allocated to the remaining firm power customers in the rate design process (PF Exchange, IP, and NR). *See* section 2.3, Table RDS 31 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

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. The amount of the new 7(c)(2) delta is $147.5 million. This amount is allocated to the PF Exchange customer class and to the NR customer class. *See* section 2.3, Table RDS 34 of Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

A third adjustment is necessary to allocate an increase in the gross Residential Exchange costs resulting from the bifurcation of the PF rate causing the PF Exchange Program rate to be higher than the average combined rate before the bifurcation. This results in higher Residential

Exchange ASC for deeming utilities. Therefore, the gross costs of the Residential Exchange must be recalculated. Any increase in such costs can only be allocated to the PF Exchange rate and the NR rate. The amount of the adjustment is $1.7 million and is determined through a set of iterations of the Residential Exchange cost model. The allocation of this amount is performed in the section 2.3, Table RDS 34A of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

After the three 7(b)(2) adjustments are made (in the absence of a need for a DSI floor rate adjustment), BPA is then able to calculate Rate Design Step energy rates for the firm power classes of service. If the DSI rate falls below the floor rate, however, one final adjustment is necessary.

3.3.5 DSI Floor Rate Test. Section 7(c)(2) of the Northwest Power Act requires that the DSI rates in the post-1985 period "shall in no event be less than the rates in effect for the contract year ending June 30, 1985." Accordingly, a floor rate test is performed to determine if the IP rate has been set at a level below the floor rate. If so, an adjustment is made that raises the DSI rate to recover revenues at the floor rate and credits other customers with the increased revenue from the DSIs. If the DSI 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 charges to test period (FY 2002-2006) DSI billing determinants. Although the energy billing determinants used for this calculation are identical to the energy billing determinants for the proposed rates, the demand billing determinants are different. The IP-83 Demand Charges are applied to billing determinants based on non-coincidental demand. The resulting revenue figure is then divided by total IP test period loads to arrive at an average rate in mills/kWh. This rate is reduced by an

Exchange Cost Adjustment and a deferral that were included in the IP-83 rate. Both adjustments are made on a mills/kWh basis.

BPA has removed all transmission costs from the IP-83 rate to make a power only floor rate comparison. The floor rate was adjusted for transmission costs by subtracting total transmission costs in mills/kWh from the original floor rate in the same manner that the Exchange Cost adjustment and deferral adjustments were completed. The mills/kWh amount 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 amounted to 3.81 mills/kWh.

These calculations result in an undelivered DSI floor rate of 20.98 mills/kWh. The floor rate is then applied to the test period DSI billing determinants to determine floor rate revenues. Revenues at the proposed IP rate charges are compared to revenues at the floor rate. Because the proposed IP rate revenues are greater than the floor rate revenues, no adjustment is necessary to the Rate Design Step IP rate. Tables RDS 23 and RDS 24 show the DSI floor rate calculation. *See* section 2.3 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.3.6 Rate Design Contra. The Rate Design Step adjustments move allocated costs between classes of service or adjust rates to account for excess revenues. Each rate design adjustment shows the classes of service to which the amount of the adjustment went. What is not shown for each rate design adjustment is the complementary accounting entry showing the source of the adjustment. The RAM keeps track of all such complementary accounting. When COSA allocated costs and rate design adjustments are summarized, it is necessary to further adjust the allocated costs by the amount of the complementary transactions. Such amounts are referred to as the rate design contra, which must be applied so that final allocated and adjusted costs to all rate classes will equal BPA's revenue requirements. *See* section 2.3, Table RDS 40 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.3.7 Rate Design Results. Table RDS 41 summarizes the allocated costs and rate design adjustments for each class of service. Rate charges are calculated for each class by dividing the allocated and adjusted energy costs by the appropriate billing determinants. Summaries of the adjusted annual average energy rate charges are shown on Tables RDS 50, 51, and 52. *See* section 2.3, Tables RDS 41, RDS 50, RDS 51, and RDS 52 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A. These annual average energy rates are shaped into monthly and diurnal periods based on the results of the Marginal Cost Analysis Study, WP-02-FS-BPA-04.

3.4 Subscription Strategy Step Adjustments

BPA's Subscription Strategy describes BPA's proposal to widely distribute the benefits of the Federal power system. The Wholesale Power Rate Development Study reflects the Subscription Strategy through the allocation of costs and credits that are specific to the Strategy. The cost allocations and rates from the Rate Design Step, above, are used as the initial starting values for the Subscription Step cost allocations.

3.4.1 Subscription Step Cost Allocation. The Subscription Strategy assumes that the IOUs in the region will choose to subscribe to BPA power, rather than continue their participation in the REP. Under Subscription, the IOUs would be entitled to 1,900 aMW of benefits priced at the RL or PF Exchange Subscription rates. BPA would offer a minimum of 1,000 aMW sold under the RL rate or PF Exchange Subscription rate. The remaining 900 aMW is modeled as a cash payment in the Wholesale Power Rate Development Study (enabling the

IOUs to buy power in the market at a net cost approximating the RL rate or PF Exchange Subscription rate), or a power sale, depending on which is the most cost-effective for BPA.

3.4.2 Initial RL Rate. In the Wholesale Power Rate Development Study, the RL rate class is a Subscription Strategy rate class whose members are expected to purchase 1,000 aMW of power. This purchase will be a flat block power of equal amounts each month. In the Rate Design Step of the Wholesale Power Rate Development Study, a FPS sale of 1,000 aMW flat at a rate equal to PF-96 was assumed. In the Subscription Strategy Step, that FPS sale is assumed not to have occurred, and the power is made available to the RL class. Initially, the RL rates are set to recover the same amount of revenue recovered by the corresponding FPS sale in the Rate Design Step, plus the applicable C&R Discount costs. *See* section 2.4, Table SUBSCR 04 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.4.3 First Subscription Step Adjustment. The first adjustment equitably allocates the cost of the cash payment to the IOUs associated with the 900 aMW between the PF Preference class and the RL class. The effect of this adjustment is to equate the two rates. *See* section 2.4, Tables SUBSCR 01, SUBSCR 02, SUBSCR 03, and SUBSCR 04 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.4.4 Second Subscription Step Adjustment. The Subscription Step assumes the IOUs will not choose to continue their participation in the REP. The rates in the Rate Design Step are set at a level sufficient to recover the net cost of the REP. The Rate Design Step rates are the starting point for the Subscription Strategy Step rates. Therefore, a credit in the amount of the net cost of the REP in the Rate Design Step must be allocated to the Subscription Strategy Step rates in order to avoid overcollecting the Subscription Step revenue requirement.

This adjustment takes into account the IP-PF link as well as the DSI floor rate test. At this point in the model, when the IP rate is set equal to the flat PF rate (minus the C&R Discount costs) plus the net industrial margin, the Subscription Step IP rate is less than the DSI floor rate. Therefore, the IP rate is set at the DSI floor and the PF and RL rates are lowered accordingly to their final Subscription Strategy Step levels. *See* section 2.4, Tables SUBSCR 01, SUBSCR 02, SUBSCR 03, and SUBSCR 04 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.4.5 Additional IP Rate Adjustments. The IP rate class sales forecast in the Rate Design Step and up to this point in the Subscription Strategy Step modeling has been 990 aMW. BPA will purchase 450 aMW specifically for the DSIs, with the understanding that the total of 1,440 aMW will be sold at rates high enough to cover the allocated costs of the 990 aMW in the Subscription Strategy Step plus the costs of the additional 450 aMW purchase. This Compromise Approach with the DSIs specifies that of the total 1,440 aMW, 1,210 aMW would be sold at about 23.5 mills and 230 aMW would be sold at about 25 mills. These rates include the cost of the C&R Discount. In modeling the Compromise Approach, the mix of cost-based power to market-based power is 870 aMW to 340 aMW, respectively, for the 23.5 mill product and 120 aMW to 110 aMW, respectively, for the 25 mill product. The initial cost-based Subscription Step IP rate (at the DSI floor) is 20.98 mills/kWh, before application of the C&R Discount costs. The five-year flat product market price for the 450 aMW of power purchases is 28.1 mills/kWh. Using the ratios and prices above, pre-C&R Discount cost rates of just under 23.0 and 24.5 mills/kWh are calculated. A portion of the cost of transmission losses associated with the 450 aMW of DSI-specific power purchases is then added to bring the two rates up to 23.0 and 24.5 mills/kWh. The remaining transmission losses cost is allocated to the PF and RL rates.

All DSI sales will be at the IP rate of 21.48 mills/kWh (the DSI floor rate of 20.98 mills/kWh plus 0.5 mills/kWh of C&R Discount costs), plus a TAC. Two IPTACs of 2.02 mills/kWh for IPTAC(A) and 3.52 mills/kWh for IPTAC(B) have been calculated using the methodology described above. The IP rate and the two IPTAC rates yield two average IP/IPTAC charges of 23.5 mills/kWh and 25.0 mills/kWh. *See* section 2.4, Tables SUBSCR 05, SUBSCR 06, and SUBSCR 07 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.5 Stepped Rates

BPA is establishing stepped rates for the five-year rate period FY 2002-2006. The posted rates will step-up by 1.5 mills/kWh after FY 2004. The RAM calculates average rates for the five-year rate period and then steps those average rates. Rates for the first three years are set at 0.6 mills/kWh below the average five-year rate. Rates for the remaining two years are set at 0.9 mills/kWh above the average five-year rate. Stepped rates will apply to the PF-02 Preference and NR-02 rate schedules. *See* section 2.5, Tables SER 01, SER 02, and SER 03 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

3.6 Slice Cost Calculation

Slice is a requirements power product. Purchasers of Slice (participants) are entitled to a fixed percentage of the generation from the FCRPS. Because Slice is calculated as a percentage of the FCRPS, the actual MW delivered to the Slice participant will vary throughout the year. During certain periods of the year and under certain water conditions, the power delivered will exceed the Slice participant's net firm requirements and may at times exceed the Slice participant's actual firm load. As a consequence, Slice entails a sale of both requirements and surplus power products.

Slice participants will assume the obligation to pay a percentage of BPA's costs, rather than pay a set price per MW and MWh. The Slice participant's obligation to pay is equal to the percentage of the FCRPS that the Slice participant 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 BPA's PBL revenue requirement identified in this rate case with certain limited exceptions. *See* Appendix C, Section 4, of the Wholesale Power Rate Development Study, WP-02-FS-BPA-05, for a detailed description of the Slice Revenue Requirement.

For the calculation of the cost of the Slice product in dollars per month for each percent of the Federal system, *see* section 2.6, Table Slice Cost 01 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

4. INTER-BUSINESS LINE REVENUES AND EXPENSES

4.1 Generation Inputs for Ancillary Services

This section describes the method BPA uses to allocate costs to the generation inputs for ancillary services**.**

4.1.1 Operating Reserves. Operating reserves are the unloaded generating capacity, interruptible load, or other on-demand rights that the control area is able to fully deploy within 10 minutes of a power system disturbance and that are capable of being used to serve load on a sustained basis for up to one hour. Operating reserves include both spinning reserves and supplemental (non-spinning) operating reserves. The Western Systems Coordinating Council (WSCC) Minimum Operating Reliability Criteria (MORC) require that each control area maintain an operating reserve equal to at least 5 percent of all hydro and 7 percent of all thermal and other non-hydro online generation within the control area.

4.1.1.1 Spinning Reserve. Spinning reserves, a part of operating reserves, are the unloaded generating capacity of a system's firm resources that are synchronized to the power system and provides additional energy as required to be immediately responsive to system frequency. WSCC requires that each control area maintain spinning reserves equal to a minimum of 50 percent of its operating reserve obligation.

4.1.1.2 Supplemental Reserve. Supplemental operating reserve is that portion of the operating reserve that does not meet the definition of spinning reserve. Generally supplemental reserve is that portion of operating reserves capable of serving load on a sustained basis within 10 minutes. WSCC requires that each control area maintain supplemental reserves equal to a minimum of its operating reserve obligation minus its spinning reserves.

4.1.1.3 General Methodology. The generation input cost for operating reserves is developed by calculating the unit cost of all FCRPS hydro projects including fish and wildlife, generation integration (GI), and step-up transformer costs. This methodology excludes the costs of WNP-2, non-performing assets, conservation, and the REP. Revenues from the generation input for generation supplied reactive and voltage control are subtracted from the FCRPS hydro cost before calculating the unit cost for the operating reserves generation input. This adjusted FCRPS hydro cost is divided by the average hydrosystem uses to determine the unit cost of operating reserves.

4.1.1.4 Calculation of Unit Cost of Operating Reserves Generation Input.

BPA calculated the average annual cost of all FCRPS hydro projects less generation-supplied reactive revenue to be $680 million. *See* section 4.4.1, Table 1 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

The forecasted average system uses (generation, spinning and supplemental operating reserve obligation and the regulating reserve obligation) is 10,055 MW. The per unit charge of $/kW/month is calculated by dividing the average system uses into the adjusted FCRPS hydro revenue requirement. The share of revenue requirement for operating reserves is determined by multiplying the unit cost by the operating reserve obligation.

4.1.2 Assumptions.

The following assumptions are used in the calculation of the unit cost of operating reserves generation input.

(1)	Average WNP-2 Output	876 MW
(2)	Average Federal hydro generation (2001-2006 rate period)	9,280 MW
(3)	5 percent of hydro (line 2 * .05)	464 MW
(4)	7 percent of thermal (line 1 * .07)	61 MW
(5)	Total reserve obligation (5 percent hydro + 7 percent thermal) (line 3 + 4)	525 MW
(6)	BPA Control Area regulating reserve obligation	250 MW

4.1.3 PBL Revenue Forecast for Operating Reserves Generation Input.

The following calculations are used in developing the PBL revenue forecast for operating reserves generation input.

Adjusted FCRPS Hydro Projects Revenue Requirement = $ 680,063,000 Revenue Requirement $ 680,063,000 ((525 MW)/(9,280 MW + 525 MW +250 MW)) =

$ 680,063,000 X 0.0522 = $ 35,500,000/ year

Per unit rate =

Adjusted FCRPS Hydro Projects Revenue Requirement /(525 MW * 12 * 1,000) =

$ 35,500,000 /(525 MW * 12 * 1,000) =

$ 5.63/kW-month based on average monthly use

PBL Revenue Forecast for Operating Reserves:

$ 5.63 /kW-month X (525 MW * 12 * 1,000) = $ 35,500,000

4.1.4 Regulating Reserve. This section describes the method BPA uses to allocate costs to Regulating Reserve generation input.

4.1.4.1 Regulating Reserve. Regulating Reserve is produced by the generating capacity of a power system that is immediately responsive to Automatic Generation Control (AGC) signals without human intervention. Regulating Reserve is required to provide AGC response to load and generation fluctuations in an effective manner. In order to maintain desired compliance with North American Electric Reliability Council (NERC) AGC Control Performance criteria, BPA currently estimates this requirement to be a minimum of 250 MW.

4.1.4.2 General Methodology. The generation input cost for Regulating Reserve is developed by calculating the unit cost. The calculation includes the costs of the Big 10 FCRPS hydro projects (*see* section 4.4.2, Table 2 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B), plus an AGC adder to account for lost efficiency and increased operation and maintenance (O&M) cost due to the provision of this service.

Regulating reserve may be provided by any of the Big 10 plants, and therefore, the cost of this service is based upon the costs of these plants. *See* section 4.4.2, Table 2 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B. The cost of the FCRPS Big 10 plants includes a share of the fish and wildlife cost and associated GI and step-up transformers costs. This methodology excludes all other hydro assets, WNP-2, non-performing assets, conservation, and the REP. Generation supplied reactive and voltage control generation input revenues are subtracted from the Big 10 cost before calculating the unit cost for the regulating reserve generation input.

4.1.4.3 Determination of Unit Cost of Regulating Reserve Generation Input. The calculation of the unit cost of regulating reserve generation input relies on the following components: average annual cost of the Big 10 FCRPS hydro projects and an AGC Adder calculation that consists of lost efficiency cost and increased O&M costs.

4.1.4.4 AGC Adder Calculation. The AGC Adder calculation includes the analysis of Efficiency Loss Cost, Increased O&M costs, and the determination of a Multiplier. The calculation combines all of these together to determine the cost for providing this service in addition to the unit cost of the Big 10 FCRPS hydro projects.

4.1.4.4.1 Efficiency Loss Cost. To analyze the efficiency loss due to AGC, BPA used load efficiency curves for typical Francis units (the type of generators at Grand Coulee and Chief Joseph) and typical Kaplan units (the type of generators on the lower Columbia and Snake Rivers). *See* section 4.4.2, Figure 1, Tables 2, 3, and 4 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B. The load efficiency curves tell how efficient the turbines are when producing a specific amount of MW at a specific head. The curves generally peak at one generation point and then decrease in efficiency as the generation moves away from that point. BPA modeled the decrease in efficiency due to operating the units way from the most efficient point along the unit efficiency curve. BPA analyzed the shape of the load efficiency curves and estimated the percent efficiency loss at midpoint of the downside and upside points of peak efficiency. For modeling purposes, BPA assumed the upside and downside generation levels were governed by points corresponding to limits of the 1 percent operating range. (If the efficiency curve was a straight line instead of a rounded curve, the efficiency loss would average 0.5 percent). The efficiency loss was calculated as 0.25 percent for Kaplan units and 0.29 percent for Francis units. The lost efficiency is multiplied by the number of hours operated and the average price of energy. *See* section 4.4.2, Table 3 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.1.4.4.2 Increased O&M Costs. The cost of maintaining the Big 10 plants was calculated and divided by the generating capacity at normal operation to determine a base value of O&M cost per kilowatt (kW). The O&M staffs at Bonneville, Grand Coulee, and the lower Snake Dams were interviewed to determine their estimate of increased O&M costs due to AGC operation. BPA multiplied the base O&M cost times this percentage to determine the increased O&M charges per kW. *See* section 4.4.2, Table 3 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.1.4.4.3 Multiplier. The multiplier is used to determine how many generating hydro units must be online to provide the required amount of AGC. Each generating unit has operational constraints that require that unit to operate between low and high generating boundaries. To provide the required amount of AGC, a generating unit must be generating at a level that will allow the unit to respond to the AGC signal by decreasing or increasing generation and while still operating the unit within operational boundaries. The boundaries in this case were determined to be within 1 percent of peak efficiency. For example, if a 100 MW unit is operated at 70 MW for peak efficiency and the lower and upper boundaries for the 1 percent limit are 60 MW and 82 MW respectively, then the range is 10 MW. This is the maximum amount of AGC that can be counted on from this unit. This means the actual MW of AGC required must be multiplied when considering effects on the generating units. In the foregoing example the multiplier would be 7 (= 70 MW/10 MW). To calculate the multiplier, unit efficiency curves for Grand Coulee, Chief Joseph, and Bonneville Dams were analyzed. The multiplier was calculated by dividing the amount of MW at peak efficiency by the smaller of the plus or minus generation range. Each separate multiplier is then weighted by the corresponding number of MW for each unit. The efficiency and O&M costs for both are multiplied by the weighted multiplier. After determining the cost for AGC provided by both Kaplan and Francis units, the portion of AGC provided by each is determined and combined to determine a composite rate. *See* section 4.4.2, Table 4 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.1.4.5 Calculation of Unit Cost of Regulating Reserve Generation Input. BPA calculated the average annual cost of the Big 10 FCRPS hydro projects less generation-supplied reactive revenue to be $576 million. *See* section 4.4.2, Table 1 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B. The forecasted average system use (generation, spinning and supplemental operating reserve obligation, and the regulating reserve obligation) is 10,055 MW. System uses that are provided by all FCRPS hydro projects (generation, spinning and supplemental operating reserve obligations) are multiplied by 89 percent to determine the Big 10 share of the obligation. The BPA Control Area Regulating reserve obligation which is provided by the Big 10 hydro projects is forecasted to be 250 MW and the TBL share is estimated to be 149 MW, the remaining 101 MW is capacity available to meet load following needs for BPA's requirements customers. The per unit charge of $6.50/kW-month is calculated using the average system use (generation, spinning and supplemental operating reserve obligations, as well as the regulating reserve obligation) divided into the revenue requirement. The revenue requirement for regulating reserve is found by multiplying the revenue requirement by the ratio of the regulating reserve obligation to the total average system uses. The Generation Input rate of $ 6.50/kW-month equals the Big 10 cost of $5.35/kW-month plus the AGC Adder of $1.15/kW-month.

4.1.4.5.1 Assumptions. The following assumptions are used in the calculation of the unit cost of regulating reserve generation input.

(1)	Average WNP-2 Output	876 MW
(2)	Average Federal hydro generation (2001-2006 rate period)	9,280 MW
(3)	5 percent of hydro (line 2 * .05)	464 MW
(4)	7 percent of thermal (line 1 * .07)	61 MW
(5)	Total reserve obligation (5 percent hydro +7 percent thermal) (line 3 + 4)	525 MW
(6)	Total control area regulating reserve obligation	250 MW
(7)	TBL regulating reserve obligation	149 MW

4.1.4.5.2 PBL Revenue Forecast for Regulating Reserves Generation Input. The following calculations are utilized in developing the PBL revenue forecast for regulating reserves generation input.

Revenue requirement X (250 MW) /(9,280 MW + 525 MW)*0.89)+250 MW) =

$ 575,894,000 X 0.028 = $ 16,039,024/year

Per unit rate =

Regulating reserve revenue requirement /(250 MW *12 * 1,000) + AGC adder

$ 16,039,024/year /(250 MW *12 * 1,000) + 1.15 = $ 5.35/kW-month + $1.15

/kW-month =

$ 6.50/kW-month based on average monthly use

PBL Revenue forecast for regulating reserve:

$ 6.50/kW-month X (149 MW *12 *1,000) = $ 11,622,000

4.1.5 Generation Supplied Reactive. This section describes the method BPA is proposing to allocate power costs to the generation input for reactive power and voltage control.

4.1.5.1 Description of Generation Supplied Reactive and Voltage Control. In addition to supplying real power, FCRPS generation facilities provide reactive power and voltage control to the transmission system. The NERC Interconnected Operations Services defines Generation Supplied Reactive and Voltage Control as the provision of reactive capacity, energy, and maneuverability from a resource in order to control voltages to support transmission system reliability. Through Order 888, FERC has identified this function as an ancillary service that a transmission provider must offer. In order to provide this ancillary service the transmission provider must acquire this service from a generation source as a generation input.

4.1.5.2 General Methodology. BPA identified the FCRPS generation-related components that are used in the production of both real and reactive power. These components, referred to collectively as "electrical plant," are the generator stator and rotor, exciters, voltage regulators, certain powerplant equipment, step-up transformers, and GI facilities. Also included is 50 percent of accessory electrical equipment. Electrical plant is used to supply both real and reactive power. Therefore, some fraction of the cost of electrical plant is allocated to the generation input for reactive power and voltage control.

The remaining plant components are used only for real power production. None of the costs of these components are allocated to the generation input for reactive power and voltage control. Plant components excluded from the allocation are dam structures, turbines, reactors, or any other items associated with water or nuclear fuel.

BPA also allocated to the generation input for reactive power and voltage control the cost of real power losses associated with the flow of reactive power in the generation equipment, as well as the costs associated with synchronous condensing, both plant modifications and energy costs.

BPA determined that the total average annual cost to provide the generation input for Reactive Power and Voltage Control is $26 million. *See* section 4.4.3, Table 1 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.1.5.3 Determining Costs of Electric Plant to Allocate to the Generation Input for Reactive Power and Voltage Control. Electrical plant is used to supply both real and reactive power. Therefore, some fraction of the cost of electric plant is allocated to the generation input for reactive power and voltage control. This section describes the methods for determining electrical plant costs.

4.1.5.3.1 Electrical Plant. The FCRPS generation-related components that are used in the production of both real and reactive power comprise the 'electrical plant,' and include the generator stator and rotor, exciters, voltage regulators, certain powerplant equipment, step-up transformers, and GI facilities. Also included is 50 percent of accessory electrical equipment. The costs of electrical plant (investment and associated O&M costs) are identified for the COE and Reclamation hydro projects on a plant-by-plant basis. The cost of electrical plant for WNP-2 is also identified.

The COE provided Property Unit Lists in which the COE assigns accounting codes to plant equipment with the associated investment and depreciation as of September 30, 1997. This provides a basis for assigning COE costs to electrical plant. The resulting net investment for electrical plant is then used to prorate costs from the COE's Combining Balance Sheets dated September 30, 1998, for each hydro project. The resulting electrical plant investment does not include electrical replacements that are planned for the rate period. Planned electrical replacements are identified separately and added to the net investment on a plant-by-plant basis. *See* section 4.4.3, Tables 2 and 3 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

For Reclamation hydro projects, electrical plant investment costs (depreciation and interest) are determined from gross plant using the Reclamation's Gross Plant Account Costs dated October 1, 1997. The turbine/generator costs are not separately identified, but are grouped together in FERC account "Waterwheels and Turbines." The generator portion of this category is estimated for each project by using the cost data from a COE hydro project with a similar turbine type/use/capacity as a proxy. The resulting gross electrical plant investment is then depreciated to determine net electrical plant investment. The resulting electrical plant investment does not include electrical replacements that are planned for the rate period. Planned electrical replacements are identified separately and added to the net investment on a plant-by-plant basis. *See* section 4.4.3, Tables 4 and 5 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

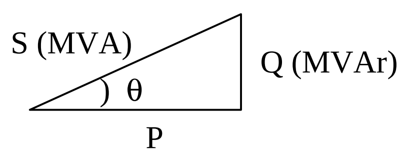
4.1.5.3.2 COE/Reclamation Planned Electrical Replacements. For plant replacements that are planned to occur during the rate period, the percentage allocated to electrical plant is determined using COE 1996, 1997, and 1998 historical expenditures. The historical expenditures are examined to determine the percent expended on electrical plant versus non-electric plant. This percentage is then applied to the Budgeted Capital Replacement Program for COE and Reclamation hydro projects on a plant-by-plant basis to determine net electrical plant replacements. *See* section 4.4.3, Tables 6 and 7 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.1.5.3.3 WNP-2 Electrical Plant. The Energy Northwest staff provided investment and depreciation data for items identified as electrical plant. BPA then determined the ratio of net electrical plant divided by net total plant (net total plant is taken from the FCRPS Combining Balance Sheets as of September 30, 1997). The resulting ratio of 0.74 percent is then used as an allocator in the Revenue Requirement Study, WP-02-FS-BPA-02, to determine annual costs of WNP-2 electrical plant. *See* section 4.4.3, Table 8 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.1.5.3.4 Operations and Maintenance (O&M) Costs for Electrical Plant. O&M costs associated with electrical plant are determined by using the Reclamation's 1996, 1997, and 1998 Operating/Program Expense Reports. To accomplish this, Reclamation staff determined the percentage of total O&M dedicated to electrical plant on a project-by-project basis. This percentage is then applied to the Budgeted O&M for COE and Reclamation hydro projects on a plant-by-plant basis to allocate the associated O&M costs to electrical plant. *See* section 4.3, Tables 9 and 10 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.1.5.3.5 O&M for WNP-2. The Energy Northwest staff provided budgeted O&M expenses for WNP-2 for the rate period. The ratio of 0.74 percent, which is the ratio of net electrical plant divided by net total plant, is used in the Revenue Requirement Study, WP-02-FS-BPA-02, to determine the portion of O&M to be allocated to electrical plant. *See* section 4.4.3, Table 8 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.1.5.4 Factor to Allocate Electrical Plant Revenue Requirement to Reactive Power and Voltage Control. Electrical plant provides both real and reactive power. To allocate a portion of the cost of electrical plant to the provision of reactive power and voltage control, the ratio "Q^2 / S^2" is used, where Q (in megavar (MVAR)) is the reactive capability of a generating unit at a particular real power output P (in MW), and S is the apparent power (in megavoltamperes (MVA)) rating of the unit. The ratio Q^2 / S^2 is derived from the relationship $S^2 = P^2 + Q^2$. Implicit in the relationship $S^2 = P^2 + Q^2$ is the power factor or "pf," which is the cosine of the angle between S and P on a power triangle. An expression equivalent to Q^2 / S^2 that yields the same result is $1 - pf^2$.



$$S^2 = P^2 + Q^2$$

Machine capability curves are used to determine the reactive output available to the transmission system when units are operated in the midrange of the peak efficiency band (the MW range of the hydro unit when it is operated within 1 percent of peak efficiency). The power factor corresponding to the given P and available Q is then calculated. Analyzing each FCRPS hydro unit in this manner yielded, on average (weighted by capacity), a power factor of 0.90. *See* section 4.4.3, Table 11 and Figure 1 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

For the hydro projects, at a power factor of 0.90, Q^2 / S^2 (or $1 - pf^2$) allocates 19 percent of the total electrical plant revenue requirement to reactive power and voltage control.

For WNP-2, the rated power factor of 0.95 is used, which allocates 10 percent of the total net electrical plant revenue requirement to reactive power and voltage control.

4.1.5.5 Synchronous Condenser Costs. The Dalles and John Day hydro projects were identified as candidates for synchronous condenser conversion to provide additional reactive capability in the lower Columbia region. To be able to operate generators as synchronous condensers, the tailwater level must be depressed below the turbine runner, which requires modifications to the turbines. The modifications have been completed for six 99 MW units at The Dalles and four 155 MW units at John Day to allow synchronous condenser operation. The major modifications and additions include the following equipment: air compressors, electrical service for compressors, control valves, pipes, control systems, and control software.

4.1.5.5.1 Plant Modifications. The investment costs associated with synchronous condenser modifications and additions at The Dalles and John Day hydro projects are identified and all of these costs are allocated to reactive power and voltage control. The annual cost of these modifications is determined in the Revenue Requirement Study, WP-02-FS-BPA-02, and the average is $ 352,000/year. *See* section 4.4.3, Table 1 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.1.5.5.2 Synchronous Condenser Energy Costs. The real power requirements of the synchronous condensing units used in the production of reactive power and voltage control are identified and all of these costs are allocated to reactive power and voltage control. BPA forecasts 73,744 MWh of energy used by synchronous condensing units. A rate of 22.33 mills/kWh, the average PF rate, is used to price the power, at a total cost of $1.65 million. *See* section 4.4.3, Table 12 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.1.5.6 Reactive Energy Losses. Real power (MW) must be produced to supply generator and exciter losses (generator stator and rotor (field) load and exciter losses). When reactive power is produced these losses increase. These losses were determined by using FCRPS generator data where the necessary data was available. Nineteen (19) percent of these losses are allocated to the generation input for reactive power and voltage control. BPA forecasts 74,893 MWh of energy consumed to produce reactive power. A rate of 22.33 mills/kWh, the average PF rate, is used to price the power, at a total cost of $ 1.67 million. *See* section 4.4.3, Tables 1 and 13 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.2 Generation Inputs for Other Services

This section defines the method for allocating costs to Generation Dropping and Station Service**.**

4.2.1 Generation Dropping. The BPA transmission system is interconnected with several other transmission systems. In order to maximize the transmission capacity of these interconnections while maintaining reliability standards, Remedial Action Scheme (RAS) are developed for the transmission grids. These schemes automatically make changes to the system when a contingency occurs to maintain loadings and voltages within acceptable levels. Under one of these schemes, the PBL is requested by the TBL to instantaneously drop large increments of generation (600 MW plus). In order to satisfy this requirement the generation must be dropped (disconnected from the system), virtually instantaneously, from a certain region of the transmission grid. Under the current configuration of the transmission grid, and the individual generating plant controls, the PBL can most expeditiously provide this service by dropping one of the Grand Coulee Third Powerhouse hydroelectric units (each of which exceeds 600 MW capacity) offline. The PBL contracted with Harza Engineering Company to work with the

Reclamation and the COE (the owners of the Columbia River system plants) to evaluate the costs of providing this "generation drop" service.

4.2.1.1 General Methodology. The overall valuation approach considered two factors. First, the desired generation drop service or "forced outage duty" imparts a wear and tear component on equipment that will incrementally decrease the life and increase the maintenance of the unit. In some cases this wear and tear component imposes more severe duty on the units than normal operation. The incremental replacement or overhaul cost is computed for each major component that is impacted by this service. Second, the incremental impact is evaluated by computing lost revenues during the outages required during replacement or overhaul of the equipment.

4.2.1.1.1 Determining Costs to Allocate to Generation Dropping. Historical data for the Grand Coulee Third Powerhouse generating units, as well as statistical data for other hydroelectric units, provided capital cost, O&M costs, and frequency of operation information for the generation dropping analysis. *See* section 4.4.4, Table 1 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B. Stresses during "forced outage duty" on the equipment versus stresses during "normal operation" are compared. Using this data, the incremental capital and/or O&M costs for the generation drop duty is developed. The analysis converts the incremental impacts of these factors that result from generation drop service into a percentage change in the life for each operation. The most likely type of overhaul or replacement that would need to be made, and the estimated capital costs for that circumstance, is evaluated in the analysis.

In addition to capital and O&M costs, the revenue lost during outages involving the overhaul or replacement of equipment is significant, especially when considering a generating unit with a capacity exceeding 600 MW. For purposes of this analysis, it is assumed that some outages could be scheduled to avoid most revenue losses required for routine maintenance. However, a cost is calculated for the outages that could not be scheduled to avoid lost revenues. These outages are longer than scheduled and/or unpredictable and could not be scheduled to avoid a loss in total project generation. *See* section 4.4.4, Table 2 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.2.1.1.2 Equipment Deterioration/Replacement or Overhaul. The effect of additional deterioration due to generation dropping is a reduced period of time between major maintenance activities, such as major overhauls or replacements. For purposes of this analysis a "major overhaul" is defined as maintenance activities where at least partial disassembly of the impacted equipment is required. The analysis focuses on evaluating the costs of additional, short-term deterioration of specific components or items for which statistical data was readily available. The costs of a major overhaul were derived from estimates or similar work performed in the past. The percentage life reductions were determined using industry standards or actual project records. For example, turbine overhaul is a major maintenance effort that will be increased in frequency as a result of more frequent severe duty cycles. *See* section 4.4.4, Table 3 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.2.1.2 Summary. The above factors are analyzed for their application on a single generating unit at the Grand Coulee Third Powerhouse and their effects combined to produce a single, overall cost associated with each generation drop.

This evaluation analysis included the major cost components that would be affected by a generation drop: reduced time between major overhauls or replacement, and increased routine maintenance. From the analyses, the total cost associated with a single generator drop of one of the Grand Coulee Third Powerhouse Units was calculated to be $195,000. This is comprised of approximately $2,000 in additional maintenance costs, approximately $39,000 in deterioration and "risk" costs to replace damaged or failed equipment, and approximately $154,000 in lost revenues. The sum of $195,000 is multiplied by the average of 1.5 generation drops required per year for a total annual cost of $293,000 per year.

4.2.1.3 Transmission Business Line (TBL) Share of Generation Dropping. TBL's share of the Alternating Current (AC) Intertie is 2,725 MW, or 79 percent of the total AC Intertie. The current annual cost per year for the Generation Dropping is $293,500. TBL's share of the annual Generation Dropping cost is $231,438.

4.2.2 Station Service. The TBL obtains station service for many of its facilities directly off the BPA transmission system. The power supplied directly off the BPA system is all supplied by the PBL. The purpose of this analysis is to identify the amount of station service being directly supplied by the PBL for use at BPA substations. This does not include station service that is being purchased by the TBL from another utility or supplied by another utility through contractual arrangements.

4.2.2.1 General Methodology. This section defines the method BPA has chosen to allocate costs to Station Service. This service is paid for by the TBL. There are very few locations on the BPA system where station service usage is metered. Because of this, a methodology has been developed to estimate the amount of kWh usage for each BPA substation. This methodology is based on the amount of primary station service transformation installed at each substation location times a load factor associated with average substation service usage. The installed station service capacity at each BPA substation was identified and classified into either small, medium, or large substations based on the amount of installed primary station service capacity. Historic data on usage, where meter data was available, was then gathered for a number of substations in each category to calculate an average load factor. The load factor is similar for each category of substation range from 6.7 percent to 10.6 percent. An overall average (weighted by transformer capacity) load factor of 9.4 percent has been selected for calculating the station service usage. *See* section 4.4.5, Table 1 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.2.2.2 Determining Costs to Allocate to Station Service. The average load factor of 9.4 percent times the installed primary station service capacity times the number of hours in the month determines the estimated station service kWh usage for each substation. The historic average station service kWh usage for the Ross Complex and the Big Eddy/Celilo Complex has been added to the calculated numbers for each of the substations to develop the station usage for the system. The Ross Complex and Big Eddy/Celilo Complex are not normal substation facilities and do not follow the developed methodology. The system station service usage is estimated to be 6,432,205 kWh-month or an average of 8.8 MW. BPA forecasts usage of 6,432,205 kWh-month of energy. A rate of 22.33 mills/kWh, the average PF rate, is used to price the power, at a total cost of $1.7 million. *See* section 4.4.5, Table 1 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.3 Segmentation of COE/Reclamation Transmission Facilities

This analysis covers transmission facilities owned by the COE and the Reclamation. The COE and Reclamation own transmission facilities associated with their respective generating projects. BPA has included all COE and Reclamation costs in the generation revenue requirement, including the costs functionalized to transmission. Therefore, the COE/Reclamation transmission investment is identified and segmented so that the annual cost of these facilities can be developed and assigned.

The COE/Reclamation transmission related investment is assigned to three segments: GI, Network, and Utility Delivery. The GI costs are assigned to generation. A share of the GI cost is used in the calculation of generation input costs for ancillary services. The remaining COE/Reclamation transmission investment is segmented to Network and Utility Delivery. The annual cost of these Network/Utility Delivery investments is credited to the generation revenue requirement, and will be included in BPA's transmission revenue requirement and assigned as an expense to the appropriate segment. The relevant segment definitions and proposed treatment are described below.

4.3.1 Generation Integration (GI). GI facilities are those facilities that connect the Federal generators to the BPA Network. This segment now includes generator step-up transformers (GSU), but does not change the assignment of GSU costs to generation, as these were previously included in generation costs. BPA continues to assign GI costs to generation.

4.3.2 Integrated Network. Integrated network facilities are those facilities that supply bulk power to the other transmission segments and operate at voltages of 34.5 kilovolt (kV) and above. BPA continues to assign these costs to transmission.

4.3.3 Utility Delivery. Utility delivery facilities are those facilities that deliver power to BPA's public utility customers at voltages less than 34.5 kV. BPA continues to assign these costs to transmission. The segmentation of these facilities is consistent with the segment definitions used in BPA's 1996 Final Segmentation Study, WP-96-FS-BPA-03, at 2-4. However, in the 1996 rate case, some of these costs were picked up by the PBL. As a result of settlement discussions, these costs are now being assigned to transmission. To the extent that the segment definitions change based on the outcome of the transmission rate case, the cost of these COE/Reclamation transmission facilities will be placed in the appropriate transmission segment.

4.3.4 COE Facilities. The transmission facilities owned by the COE are primarily GSU and associated equipment at the plants. These costs are all GI, which is assigned to power**.** The only exception is at the Bonneville Project. At Bonneville Powerhouse No. 1, the COE owns the switching equipment located on the dam that is used for both Network and GI. *See* section 4.5.1 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.3.5 Reclamation Facilities. Reclamation usually owns the lines and substations at its plants. The primary function of these facilities is to connect the generators to the Network, but at some plant substations there are facilities that perform either a Network or Delivery function. Worksheets used in this Study show the allocation of the line and substation investment at each Reclamation project into the appropriate segment. *See* section 4.5.2 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B, for the Columbia Basin project (Grand Coulee). *See* section 4.5.3 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B, for the other Reclamation projects. The available Reclamation investment data did not breakdown costs to the equipment level. To develop investment by segment(s) typical costs were used as a proxy for major pieces of equipment. The proxy investment by segment were divided by the total proxy investment for each station total to develop a percentage for each segment as a percentage of the total transmission investment.

The segment percentage was multiplied times the total transmission investment for each station to determine the segment investment.

4.4 PBL Transmission Expense Sources

PBL incurs transmission expenses from three source categories: (1) "Grandfathered contracts"; (2) market sales; and (3) other transmission expenses. The annual transmission expense cost averages $121.6 million per year for the period FY 2002-2006. *See* section 4.3.2 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B, Table Annual Transmission Expense FY 2002-2010 and section 4.3.3, Table Monthly Transmission Expense.

4.4.1 Grandfathered Contracts. "Grandfathered contracts," which currently use BPA's FPS-96 power rate schedule, were entered into prior to July 12, 1996, and include transmission requirements that extend beyond September 30, 1996. PBL purchases transmission under the Point-to-Point (PTP) tariff from the TBL for power deliveries made under the Grandfathered contracts. Transmission demands are based solely upon power sales contract demands executed prior to July 12, 1996. TBL charges PBL the PTP monthly rate applied to the transmission demands specified for service to Network Point of Deliveries (POD), and the additional Southern Intertie (IS) monthly rate applied to the transmission demands for service over the IS. The total transmission demand for the Network is the highest monthly demand aggregated on a monthly basis for all contracts that provide for such service. This methodology also applies to Intertie South transmission service. The five-year average annual cost for "Grandfathered contracts" during the rate period is $52.0 million. *See* section 4.3.4, Transmission Billing Determinants Associated with "Grandfathered contracts" (MW) table in the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.4.2 Market Sales. For contracts that use BPA's FPS-96 power rate schedule that were entered into after July 12, 1996, and that include transmission requirements, PBL acquires PTP transmission to make deliveries. These delivered sales include short-term (hourly, daily, monthly) and long-term (yearly and multiyear) sales. PBL has pre-purchased long-term IS transmission (to COB and Nevada-Oregon Border (NOB)) for marketing purposes. In general, transmission for long-term sales and sales to the Network PODs is purchased on an as-needed basis. TBL is the transmission provider to many of the Network PODs to which PBL sells and TBL owns a large quantity of the IS capacity. Therefore, PBL is expecting to purchase the majority of its transmission needs from TBL at the posted PTP transmission rate.

The amount of firm transmission needed for delivered power sales (85 percent of all HLH sales, 75 percent of LLH sales) was calculated based on the forecasted amount of HLH sales. For delivery of LLH sales, BPA expects to use unused firm transmission that was purchased for the HLH sales and then purchase incremental Hourly Non-Firm (HNF). The five-year average annual cost for Market Sales expense category during the rate period is $69.7 million. *See* section 4.3.4, Market Sales Forecast for Transmission Purchases table in the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.4.3 Other Transmission Expenses. In addition to the transmission services listed above, the following services are included in the transmission expense forecast: (1) the cost of delivering energy under the Pacific Northwest Coordination Agreement (PNCA) and the Non-Treaty Storage Agreement (NTSA) (averaging an annual expense of $1.8 million); (2) the cost of purchasing backup transmission from parties other than the TBL (averaging an annual expense of $2.0 million); (3) a $1 million per year charge paid by Montana Power Company (MPC) to BPA pursuant to a contractual agreement between BPA and MPC; and (4) a $1 million per year credit paid to BPA under the Canadian Entitlement Agreement.

4.4.4 Forecasted Transmission Rate Assumptions. For the Network transmission base rate, the PBL assumes a 25 percent increase on the 1996 PTP/NT base charge of $12/kW-year to

$15/kW-year, plus a reactive charge of $1.0/kW-year, plus a charge for operating reserves of $1.5 /kW-year, for a total charge of $17.5/kW-year. This Network rate is used for both the PTP Service base charge and the NT Service base charge. *See* section 4.3.1, "Transmission Rate Assumption Summary" table in the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

PBL anticipates the load shaping component of the 1996 NT service will be removed as a separate charge in the post-2001 period consistent with the assumption that TBL will change cost allocation from the current one non-coincidental peak method to a 12 coincidental peak method.

The result of this cost allocation change would be elimination of transmission load shaping charges.

PBL used a cost-to-rate increase ratio where every $10 million in increased costs increases the Network rate by 3 percent. The assumed post-2001 annual charge of $15/kW-year is a 25 percent increase in the 1996 PTP/NT base charge of $12.0/kW-year though in post-2001. PBL assumes transmission customers will need to pay additional charges for operating reserves and reactive. PBL expects these charges to be approximately $1.0/kW-year for reactive and $1.5/kW-year for operating reserves. The base charge, together with the additional charges for operating reserves and reactive, equates to a PTP rate of $17.5/kW-year or a 45.8 percent increase from the 1996 base PTP rate of $12/kW-year. Under the 1996 NT rate schedule, the cost of NT service with load shaping as a separate charge is $1.539/kW-month and, under BPA's assumptions, the cost including the base charge, operating reserves, and reactive will be $1.46/kW-month. The billing factors are assumed to be the same as in BPA's 1996 rate schedules for PTP and NT services.

The HNF rate, which is a per MWh rate, is assumed to increase at the same rate as the PTP service with reactive and operating reserves included. The HNF rate is expected to average $3.46/MWhs in the rate period FY 2002-2006.

PBL anticipates rate escalation on the IS caused by a demand trend towards short-term transmission service. The assumed post-2001 annual charge of $16.82/kW-year is a 10 percent increase in the 1996 IS rate schedule of $15.29/kW-year. *See* section 4.3.1, Table "Transmission Rate Assumption Summary" of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

4.5 General Transfer Agreement (GTA) for Federal Power Deliveries

Many of BPA's power customers are located in or near an IOU transmission system. BPA serves these customers by contracting with the local IOU to use its transmission facilities to serve BPA's wholesale power customers. The PBL includes the anticipated cost of the GTA used for Federal power deliveries into the PBL revenue requirement. The costs were developed using customers' anticipated MW levels for FY 2001 and the corresponding GTA rate. An adjustment was added for delivery under open access tariffs. The costs associated with low voltage delivery facilities used by GTA customers are not included in the transmission forecast; BPA will conduct a separate rate proceeding to develop a rate to collect these costs from the GTA customers that utilize these facilities.

The GTA costs by year can be found in the COSA 10 table in section 2.2 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A. The total cost of the GTA over the five-year rate period is $236 million.

5. REVENUE FORECAST

This section describes the revenue forecast prepared for BPA's 2002 rate proposal and presents the results of that forecast.

5.1 Overview

The revenue forecast is BPA's expected level of sales and revenue for the rate period, FY 2002 through 2006. BPA prepares two revenue forecasts: (1) one using current rates; and (2) one using proposed rates. These revenue forecasts are used to demonstrate that existing rates do not satisfy BPA's revenue requirements and that proposed rates satisfy BPA's revenue requirements. The revenue test is described in the Revenue Requirement Study, WP-02-FS-BPA-02. The rates placed in effect October 1, 1996, are used in the calculation of revenues at current rates for FY 2000 through 2006. The proposed rates are developed in the Wholesale Power Rate Development Study, based on the loads forecasted in BPA's rate proposal. The proposed rates are then applied to those loads, from FY 2002 through 2006

5.2 Sources of BPA's Revenue

PBL revenues are divided into five groups. The first (and largest) source of revenues is from the sale of firm Subscription and Pre-Subscription power to regional public agencies, Federal agencies, IOUs, and DSI customers. In FY 1999 these revenues totaled $1,076 million. In addition to these revenues, the PBL also collected $55 million in FY 1999 from these customers for the TBL for the transmission of Federal power.

The second revenue source is long-term contractual obligations where the rates are already determined by contract or by contract formula. These include contracts with several IOUs, municipalities, Federal agencies, public agencies, and power marketers. In FY 1999 these revenues totaled $309 million.

The third source of revenues is short-term energy sales, where rates are determined in the market. This includes power sold on a monthly, weekly, daily, and hourly basis, as well as some revenues earned from the sale of options to purchase power. In FY 1999, short-term power sales generated revenues of $768 million.

The fourth source of revenues is from the sale of generation inputs for ancillary and reserve products. The major component of this group is revenues from generation inputs provided to the TBL. In FY 1999, revenues from all generation inputs and reserve product sales were $53 million.

The last revenue group is revenue credits from the U. S. Treasury. These include section 4(h)(10)(C), FCCF, Colville Settlement, and the COE, and Reclamation payments. The credit associated with BPA payments to the Colville Tribe for the use of reservation land for power production is fixed by statute. BPA also receives credit for COE and Reclamation payments to the U.S. Treasury for upstream benefits from owners of downstream projects. These upstream benefit payments were assumed equal to the payment for FY 1998. In FY 1999, these credits and miscellaneous revenues totaled $65 million.

**5.2.1.	In-Region Subscription and Pre-Subscription Sales.** In-Region Subscription and Pre-Subscription sales of firm power are the basic products that the proposed rates are designed to cover. Most of BPA’s firm power will be sold under these contracts. The revenues from these contracts are estimated by applying the current PF, FPS, and IP rates (or the proposed PF, FPS, RL, or PF Exchange Subscription, and IP rates) to the projected billing determinants. For purposes of estimating revenues using current rates, the rate for power sales to IOUs was assumed to equal the PF rate. The LDD, the C&R Discount, and a mitigation adjustment were also assumed. When applying current rates to these loads, the revenues from these sales average $1,410 million per year. When applying proposed rates to these loads, the revenues average $1,432 million per year.

5.2.2 Contractual Formula Rates. Some of BPA's contracts include contractually specified formulas for calculating rates. These rates are based on a variety of factors including increases in the PF rate, increases in the NR rate, changes in the BPA Average System Cost (BASC), and the price of oil and gas. These contracts are assumed to be in the sale mode from FY 2000 through 2006 or until the contracts expire. Revenues from PBL in-region and out-of-region long-term contract sales will average $304 million per year. *See* section 3.2 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

5.2.3 Short-Term Market Sales and Power Purchases. For rate development purposes BPA projects firm loads based upon critical (*i.e.*, 1937) water conditions. The revenue forecast reflects BPA sales of energy created by streamflows in excess of critical water. In FY 1999, BPA sold 4,370 aMW of power from its trading floor for more than $768 million. Most of this power was sold under the FPS rate schedule for periods as short as one hour or as long as the entire year. Revenues from short-term market sales are projected to average about $516 million using either the current or proposed rates during the FY 2002–2006 rate period.

5.2.3.1 Short-term Market Sales and Purchases. The calculation of short-term market sales begins by calculating monthly HLH and LLH energy surpluses and deficits in the RiskMod model. This analysis, referred to as the Federal Secondary Energy Analysis (FSEA), involves estimating energy surpluses and deficits using forecasted loads, non-hydro resources, and varying hydro generation. RiskMod uses results from two hydroregulation models--Hydro Simulation (HydroSim) and the Hourly Operating and Scheduling Simulator (HOSS), and load forecast studies, to compute the available HLH and LLH surplus energy, as well as HLH and LLH energy deficits in the Federal hydrosystem under varying streamflow conditions.

The FSEA is used to forecast the amount of surplus energy available for sale as well as the amount of power purchases needed to meet BPA's loads under different water conditions. The available energy surplus or deficit is determined by subtracting total firm loads from total Federal generation using forecasted Federal hydro generation for 50 historical water years under current hydro operation constraints. The 50 historical water years cover a broad spectrum of streamflow conditions from very dry to very wet. The results of the FSEA are shown in section 3.3 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

5.2.3.2 Short-Term Market Revenues and Purchased Power Expense. An analysis of surplus energy revenues and purchased power expenses was performed using RiskMod. RiskMod estimates HLH and LLH surplus energy revenues and purchased power expenses for the 50 water years based on results from the FSEA. HLH and LLH prices used in the analysis were based on prices forecasted by the AURORA model. *See* Risk Analysis Study Documentation, WP-02-FS-BPA-03A. These prices were modified in RiskMod to reflect BPA's experience during periods when substantial amounts of electric power are available for sale. BPA forecasts that revenue from short-term sales will average $488 million per year during the rate period.

BPA projects that expenses associated with short-term purchases will average $89 million per year during the rate period. The forecasted revenues from RiskMod for short-term market sales and purchased power expenses are noted in sections 3.3 and 3.4 respectively of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

5.2.3.3 Section (4)(h)(10)(C) Credits and FCCF. The average annual section 4(h)(10)(C) operational credits that BPA can claim when making its annual U.S. Treasury payments were obtained from RiskMod. These average annual values were derived by estimating the amount of 4(h)(10)(C) operational credits that BPA could claim under each of the 50 historical streamflow conditions and then adding them to the other 4(h)(10)(C) credits that BPA will receive. Market prices used to estimate the 4(h)(10)(C) operational credits were the same market prices used to estimate short-term surplus market sales revenues and purchased power expenses. BPA determined the additional costs of the fish and wildlife recovery programs by comparing purchased power expenses associated with: (1) FCRPS operations before the restrictions were placed on river operations; and (2) FCRPS operations using current restrictions. BPA 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, became the base firm energy load for this forecast. The cost of the increased purchases was estimated using RiskMod and the market price forecast used elsewhere in this rate proposal. A portion of the increased purchased power expenses (27 percent) is included in the section 4(h)(10)(C) credit. The total section 4(h)(10)(C) credit is forecast to average $92 million per year during the rate period. The section 4(h)(10)(C) credit calculations are shown in section 3.5 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

The annual average FCCF credit that BPA can claim when making its annual U.S. Treasury payment is also estimated using RiskMod. This average annual credit reflects the expected amount of FCCF credits that BPA can claim in each subsequent year, after accounting for the potential depletion in the FCCF fund prior to the beginning of FY 2002 and from FY 2002 through 2006. The estimated FCCF credits are from the 15 of the 50 water years when projected surplus revenues less purchased power expenses (*i.e.,* net surplus revenues) are the lowest. The credit is equal to the difference between the net surplus revenues in these years and the net surplus revenues in the 16th worst runoff condition. The average expected value of the FCCF credit is projected to be $26 million per year during the rate period. *See* section 3.6 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

5.2.4 Generation Inputs to Ancillary and Reserve Products. Revenues from generation inputs for ancillary services and other services sold by TBL that contain a generation component include: Load Regulation, Control Area Reserves, Transmission Losses, Remedial Action, Reactive Power, and Energy Imbalance. Also, the PBL receives revenues from Reserve Services it provides to others. In FY 1999, revenues from the generation input for Load Regulation totaled $13 million; revenues from generation services related to other ancillary services sold by TBL totaled $30 million; and revenues from Reserve Services sold to other parties by the PBL totaled $2.5 million. Revenues from the sale of generation inputs for ancillary services and reserve power products at both the current and proposed rates are contained in sections 3.8 and 3.9, respectively of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A. During the rate period, revenues from generation inputs for ancillary services and reserve products are projected to generate about $49 million per year at current rates and about $81 million per year at proposed rates. A complete discussion of how revenues from generation inputs for ancillary services and reserve products are determined is contained in the previous chapter.

5.2.5 Energy Efficiency. BPA projects revenues of about $13 million per year from the sale of Energy Efficiency products and services. Energy Efficiency revenues are documented in BPA budget estimates prepared in 1998. Energy Efficiency revenues are in section 3.7 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

5.3 Load Forecasts

The proposed load forecasts used in the revenue forecast are the source of energy and demand billing determinants used to calculate rates and revenues. The energy load forecasts include forecasted energy loads of PF, IP, NR, RL, and FPS sales. The energy load forecasts used in this rate proposal are documented in the Loads and Resources Study, WP-02-FS-BPA-01, and the Loads and Resources Study Documentation, WP-02-FS-BPA-01A.

The firm loads expected using current rates are the same as the firm loads expected using proposed rates, because the rates are almost the same. Because the forecast of Subscription power is the same, the forecast of open market sales and purchased power expenses is also the same. The only thing that differs in these forecasts is the rate at which firm power is sold and the revenues from those sales.

5.4 Revenue Forecast Methodology

The first step in developing the revenue forecast is to apply rates to the forecasted firm loads. For long-term contracts, that determination was made separately and the revenues were summed and added to the forecast. The sales made under regional Pre-Subscription FPS contracts were multiplied by the PF rate components. The load shaping (load variance) charge was assumed to apply to all energy sold under these contracts. Finally, a fixed contract collar adjustment was made to the forecast to reflect the impact of contract price limitations.

Next, regional Subscription power sales billing determinants from the load forecasts were applied to the appropriate set of rates to calculate BPA's expected revenue. Revenues from long-term contract sales, miscellaneous products and services, transmission services, and unbundled power products were added to the power revenues.

5.4.1 Other Factors Affecting Forecasted Revenues. Other factors affecting forecasted revenues include the LDD, the C&R Discount, and a mitigation adjustment, which are described below.

5.4.1.1 Low Density Discount (LDD). The LDD is projected to be about $14 million per year and is expected to have about the same financial impact during the proposed rate period as in the current rate period. The historical LDD from FY 1998 can be found in section 3.10 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

5.4.1.2 Conservation and Renewable Discount (C&R Discount). The C&R Discount of one-half mill/kWh is provided to all regional Subscription sales made to public agencies, DSIs, and IOUs under the current and the proposed rates. A C&R Discount of one-half mill/kWh is multiplied by the energy sales to obtain the total rate discount. The C&R Discount provided to preference customers averaged slightly more than $18 million per year, the C&R Discount provided to DSI customers averaged about $6 million per year, and the C&R Discount to IOUs averaged about $4 million per year during the FY 2002 through 2006 rate period.

5.4.1.3 Mitigation Adjustment. A mitigation adjustment of $4 million per year during the FY 2002-2006 rate period is applied to PF sales. The mitigation adjustment is shaped over the months of the year. The monthly shape of the mitigation adjustment is the same as the shape of the irrigation discount received by BPA customers during FY 1996. This discount is documented in section 3.11 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A.

5.4.1.4 Collar Adjustment. A collar adjustment of $7.5 million was made to the FY 2002-2006 period at proposed rates to reflect the contractual price limits associated with the Pre-Subscription contracts to public utilities.

5.5 FY 1999 through FY 2001 Revenues

Forecasted revenues using current rates for FY 1999 through 2001 are shown in section 3.1 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A. Revenues in FY 1999, excluding revenues from the REP, were $2,175 million. Revenues from firm power sales to public utilities and Federal customers at the PF and FPS rates were $739 million in FY 1999, $769 million in FY 2000, and $794 million in FY 2001. Revenues from firm power sales to these customers in FY 1998 totaled $715 million.

Revenues from firm power sales to DSI customers under the IP rate with applicable transmission and FPS rates were $339 million in FY 1999, and are projected to be $352 million in FY 2000, and $357 million in FY 2001.

Long-term surplus contract revenues, including sales at PPL-90, MSL-87, and MSC-86 rates, and other contracts that are determined by prior contractual arrangements, were $309 million in FY 1999, and are projected to be $311 million in FY 2000, and $331 million in FY 2001.

Revenues from the sale of generation inputs for ancillary and reserve products were $45 million in FY 1999, and are projected to be $45 million in FY 2000, and $48 million in FY 2001.

Revenues from section 4(h)(10)(C) credits were $36.5 million in FY 1999, and are projected to be $72.3 million in FY 2000, and $73.3 million in FY 2001. Credits are based on actual water conditions in FY 1999. In future years, projected section 4(h)(10)(C) credits are estimated using the average of 50 water conditions.

Revenues from the FCCF credit were zero in FY 1999, and are projected to be zero in FY 2000, and $34.5 million in FY 2001. *See* section 3.1 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A. Future FCCF credits are based on a probabilistic estimate using the average of 50 water years. In 35 of those years there is no FCCF credit.

Revenues credited to BPA associated with the Colville settlement are $17 million in FY 1999, $18 million in FY 2000, and $18 million in FY 2001. The Colville payment credit declines to $4.6 million per year in FY 2002 and remains at that level.

COE and Reclamation revenues credited to BPA from owners of downstream hydroelectric projects were slightly greater than $8 million in FY 1998 and are projected to remain at this level.

Miscellaneous revenues from the Energy Service activities and other sources were $3 million in FY 1999, and are projected to be $34 million in FY 2000 and $40 million in FY 2001, due to the addition of revenues from Energy Service activities in FY 2000 and beyond.

Revenues collected for the TBL were $63 million in FY 1999, and are projected to be $64 million in FY 2000, and $64 million in FY 2001. The PBL accrues about $9 million per year from diversification fees paid by customers after the establishment of BPA's 1996 rates.

5.6 Revenue for FY 2002 through 2006

Forecasted revenues under current rates for the rate period, FY 2002 through 2006, are shown in section 3 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A, as are revenues forecasted under proposed rates for the FY 2002 through 2006 rate period. Pre-Subscription contract sales to preference customers are made at the FPS rate, which was assumed to equal the PF rate for both the current and proposed rates. Pre-Subscription sales to IOUs and marketers are included with other long-term contracts. Forecasted revenues under current rates also includes a 450 aMW sale to the DSIs at an FPS rate of 28.1 mills/kWh to cover the cost of additional resources acquired to serve this load.

5.7 Revenues for FY 2002 through 2006 at Current Rates

Revenues estimated under current 1996 rates are shown in section 3.12 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A. Total revenues from all sources are projected to be $2,430 million in FY 2002, $2,445 million in FY 2003, $2,400 million in FY 2004, $2,423 million in FY 2005, and $2,436 million in FY 2006.

5.8 Revenues for FY 2002 through 2006 at Proposed Rates

Revenues estimated under proposed rates are shown in section 3.13 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A. Revenues at proposed rates are projected to be $2,482 million in FY 2002, $2,498 million in FY 2003, $2,452 million in FY 2004, $2,477 million in FY 2005, and $2,492 million in FY 2006.

6. RATE SCHEDULE DESCRIPTIONS

The wholesale power rates developed in the Wholesale Power Rate Development Study are incorporated in the Wholesale Power Rate Schedules. The Wholesale Power Rate Schedules, WP-02-A-02, Appendix 1, include two sections. The first section contains the Wholesale Power Rate Schedules. Each rate schedule states to whom the rate schedule is available, rates for the products offered under the schedule, billing factors, and references to sections of the GRSPs that apply to that rate schedule. The Wholesale Power Rate Schedules also state appropriate transmission purchasing policies for power customers. The second section contains the GRSPs for power rates. The GRSPs include adjustments, charges, special rate provisions, and two lists of definitions, one of products and services and one of rate schedule terms.

Purchases under the PF, RL, NR, and IP rates are subject to the CRAC, the Dividend Distribution Clause (DDC), the C&R Discount, and the GEP. The Slice Product will be subject to the C&R Discount; however, it will not be subject to the CRAC, DDC, or the GEP. In addition, the PF Exchange Program rate will not be subject to the C&R Discount rate or the GEP.

6.1 Priority Firm Power Rate, PF-02

The PF-02 rate schedule replaces the PF-96 rate schedule. The PF-02 rate schedule is available for the purchase of power by public bodies, cooperatives, Federal agencies, and utilities participating in the Residential Exchange under section 5(c) of the Northwest Power Act. PF must be used to meet the purchasers firm loads within the PNW.

The PF-02 rate schedule includes sections applicable to different types of purchasers under the 2002 Contracts and the Residential Purchase and Sale Agreement (RPSA). Rates for PF demand and energy, Load Variance, and Slice have been developed. At its discretion and subject to specified limitations, BPA also may make available: (1) the Flexible PF Rate Option, which includes rates and billing factors as mutually agreed upon by BPA and the Purchaser; or (2) the Cost–Based Indexed PF Rate, which is a risk-adjusted market-indexed or floating price rate. Preference customers may purchase under the PF-02 rate schedule for a three- or five-year period pursuant to their power sales contract with BPA. Residential Exchange customers may purchase under the REP or Subscription settlements of the REP only for five-year terms. Block Products are available and may be subject to a SUMY block charge.

The PF-02 demand rate is seasonally differentiated. The PF-02 energy charges are seasonally and diurnally differentiated. *See* sections 2.1 and 2.2 of the Wholesale Power Rate Development Study, WP-02-FS-BPA-05, that describe these methods.

Most purchases under the PF-02 rate schedule are subject to certain provisions of the GRSPs, including among others the TAC, LDD, the Unauthorized Increase Charge (UAI Charge), and in some cases, the Excess Factoring Charge. These are described earlier in this document. Purchases under the PF-02 rate schedule also are subject to BPA's billing process.

6.1.1 Targeted Adjustment Charge (TAC). The TAC applies to the PF rate schedule, except the Slice Product, the PF Exchange Program and the PF Exchange Subscription rates. In addition, the TAC also applies to the NR rate schedule. The TAC applies to firm power requirements service to regional firm load that results in an unanticipated increase in BPA's projected loads within the rate period. The TAC will be applied to the applicable rate for requirements service requested after the Subscription window closes.

The TAC will also apply to subsequent requests made by a customer under a Subscription contract for requirements service for such customer's load(s) that had been previously served by that customer's 5(b)(1)(A) or 5(b)(1)(B) resources. For a further discussion of the TAC, *see* section 2.12 above.

6.2 New Resource Firm Power Rate, NR-02

The NR-02 rate schedule replaces the NR-96 rate schedule. The NR-02 rate schedule is available for purchase of power by IOUs under net requirements contracts for resale to consumers, and to publicly owned utilities for NLSLs. Similar to the PF-02 rate schedule, the NR-02 rate schedule includes sections applicable to different types of purchasers under the 2002 Contracts.

Products available under the NR-02 rate schedule include NR demand and energy, and Load Variance. At its 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. The NR rate schedule specifies which transmission rate schedule(s) may apply to purchasers under the NR rate schedule. The NR-02 rate includes a seasonally differentiated Demand Charge and seasonally and diurnally differentiated energy charges for three- or five-year periods. Block Products are available and may be subject to a SUMY charge. Purchases under the NR-02 rate schedule are subject to certain provisions of the GRSPs, including among others the LDD, the TAC, the UAI Charge, and in some cases, the Excess Factoring Charge. These are discussed in the Wholesale Power Rate Development Study above. Purchases under the NR-02 rate schedule are subject to BPA's billing process.

6.3 Residential Load Firm Power Rate, RL-02

The RL-02 rate schedule is a new rate schedule. It applies to firm power sales to IOUs under net requirements contracts for resale to residential consumers. In order to purchase firm power under this rate schedule, an IOU must agree to waive its right to request benefits under section 5(c) of the Northwest Power Act for the term of the contract purchase. Each IOU will be able to purchase only a specified amount of firm power at the RL rate. Additional requests for requirements service above such amount will be made under the NR-02 rate schedule.

The only product available under the RL-02 rate schedule is Block Firm Power demand and energy. This product will be delivered in equal hourly amounts over the period. If the purchasing IOU is no longer the serving utility for a portion of its former residential load, then its purchases under this rate schedule will be decreased pro rata.

The consumer bills of participating IOUs should designate "Benefits of the Federal Columbia River Power System" to describe the amount of benefits each consumer receives.

The RL-02 rate schedule is for a five-year rate period and includes a Demand Charge with seasonal differentiation and energy charges that are seasonally and diurnally differentiated. Purchases under the RL-02 rate schedule are subject to provisions of the GRSPs, as listed in the rate schedule, and are subject to BPA's billing process. GRSPs applicable to purchases under the RL-02 rate schedule include the UAI Charge.

6.4 Industrial Firm Power Rate, IP-02

The IP-02 rate schedule replaces the IP-96 rate schedule. The IP-02 rate schedule is available to BPA's DSI customers for firm take-or-pay block power to be used in their industrial operations.

The IP-02 rate includes a seasonally differentiated Demand Charge and energy charges that continue to be seasonally and diurnally differentiated. Purchases under the IP-02 rate schedule may be up to five years and are subject to provisions of the GRSPs, as listed in the rate schedule. The Load Variance Charge might be applicable if other products are purchased. At its discretion and subject to specified limitations, BPA also may make available: (1) the Flexible IP Rate Option, which includes rates and billing factors as mutually agreed upon by BPA and the Purchaser; or (2) the Cost–Based Indexed IP rate, which is linked to aluminum prices as measured by the LME for their three-month aluminum contract denominated in U.S. dollars. The indexed rate being proposed is similar to the variable industrial power rates that BPA adopted in past rate cases. For the 2002 rate proposal, BPA is including an IPTAC, described in the section 2.13 above, and a Supplemental Contingency Reserves Adjustment (SCRA), as described in Appendix B. Purchases under the IP-02 rate schedule also are subject to BPA's billing process.

6.4.1 Industrial Firm Power Targeted Adjustment Charge (IPTAC). The IPTAC pertains to the IP rate schedule. The IPTAC will be applied to Firm Power requirements service of DSIs who take service under the IP-02 rate schedule. The IP-02 rate is developed from a combination of Federal inventory and power purchased from the market during FY 2002-2006 rate period.

The total inventory used to provide this requirement service will be composed of 990 aMW from Federal inventory and 450 aMW of market purchases. The maximum total requirements service the IPTAC will be developed for, and applied to, is 1,440 aMW (flat, annual block).

There will be two rates for the IPTAC. The IPTAC(A) is 1,210 aMWs and will be sold at $23.50/MWh. The IPTAC(B) is 230 aMWs and will be sold at $25/MWhs.

6.5 Nonfirm Energy Rate, NF-02

The NF-02 rate schedule is available for purchases of nonfirm energy both inside and outside of the PNW, and outside the United States. The NF-02 rate schedule also may be used for transactions under the Western Systems Power Pool (WSPP) agreements. As with the NF-96 rate schedule, the NF-02 rate has four components: the Standard rate, the Market Expansion rate, the Incremental rate, and the Contract rate. In addition, the NF-02 rate schedule allows BPA and an end-user to agree to a rate or rate formula within the range limited by the Standard and Market Expansion rates. There are five changes to the NF rate schedule from NF-96.

(1) Delete the sentence: "All rates and any subsequent adjustments contained in this rate schedule shall not exceed in total the NF Rate Cap calculated in accordance with the methodology specified in the Adjustments, Charges, and Special Rate Provisions section of this document."

(2) Delete the sentence: "For purchases under NF-96 rate schedule, transmission service shall be charged under the applicable transmission rate schedule."

(3) Add Unauthorized Increase to the list of Special Rate provisions.

(4) Change Section III.C(3) from "that has an Incremental Cost greater than the Standard rate (plus the Intertie Charge, if applicable) less 2.00 mills/kWh" to "that have an Incremental Cost greater than the Standard Rate (plus the Intertie charge, if applicable) minus 2 mills."

(5) Update the average cost of nonfirm energy using the methodology that was used in 1996.

The average cost of nonfirm energy (*see* below for calculation description) is 25.18 mills/kWh. The Standard rate is related to the average cost of nonfirm power since it is a flexible rate with an upper limit of 120 percent of the average cost of nonfirm energy. This final Proposal contains a Standard rate of 30.22 mills/kWh. The Standard rate serves as BPA's general nonfirm energy marketing rate. BPA will make offers of nonfirm energy first at the Standard rate. Pricing flexibility is included in the Standard rate to allow the rate to be competitive in volatile markets.

The NF-02 Contract rate is 25.18 mills/kWh, which is equal to the average cost of nonfirm energy. The Contract rate is established for contracts that refer to the NF-02 rate schedule to determine the value of energy.

APPENDIX A

7(C)(2) INDUSTRIAL MARGIN STUDY

APPENDIX A

7(C)(2) INDUSTRIAL MARGIN STUDY

1. INTRODUCTION

Section 7(c)(1)(B) of the Northwest Power Act provides that rates applicable to DSI customers shall 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."

Section 7(c)(2) provides that this determination shall be based on "the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates." This section further provides that the Administrator shall take into account

(1) the comparative size and character of the loads served;

(2) the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions; and

(3) direct and indirect overhead costs, all as related to the delivery of power to industrial customers.

2. PURPOSE

The purpose of this study is to describe the calculation of the "typical margin" included by the Administrator's public body and cooperative customers in their retail industrial rates. The resulting margin is added to the PF-02 energy charges. These adjusted PF-02 energy charges and Demand Charges are applied to the DSI billing determinants to determine the IP-02 rate.

3. METHODOLOGY

3.1 Administrator's Applicable Wholesale Rates to Public Body and Cooperative Customers

BPA applies the PF-02 demand and energy charges (before any 7(b)(2) or floor rate adjustments) to the forecasted DSI billing determinants.

3.2 Typical Margin

The "typical margin" includes "other overhead costs" charged by the utilities in the study. BPA's power revenue requirements are accounted for in the PF rate charges, and distribution costs are included by adding in a charge for BPA's DSI delivery facilities. An overall margin is derived by weighting individual utility margins according to the proportion of industrial energy load served by each utility relative to total industrial energy load included in the study.

3.3 Margin Determination Factors

3.3.1 7(c)(2)(A) – Comparative Size and Character of the Loads Served. The data base used for the study includes utilities that serve at least one industrial customer with a peak demand of at least 3.5 MW.

3.3.2 7(c)(2)(B) – Relative Costs of Electric Capacity, Energy, Transmission, and Related Delivery Facilities Provided and Other Service Provisions. The utility margins in this study are based to the extent possible on utility cost of service analyses and incorporate allocated costs to the industrial customer class. The utilities segregate these costs into various cost categories, and only those categories considered to be appropriate margin costs are included in BPA's industrial margin calculation.

In the past, BPA has accounted for "other service provisions" through a character of service adjustment for service to the first quartile. Because the DSI contracts no longer include these provisions, BPA has not made this adjustment as part of this study.

3.3.3 7(c)(2)(C) – Direct and Indirect Overhead Costs. BPA relies on cost of service studies and other spreadsheets prepared by the public body and cooperative customers to incorporate the per unit overhead costs associated with service to large industrial customers.

4. APPLICATION OF THE METHODOLOGY

The derivation of the margin involves two steps. First, an individual margin is determined for each utility in the study. Second, each margin is weighted according to energy sales to derive an overall margin. BPA's DSI delivery facilities charge is added as a later step to replace the distribution costs that otherwise would be included in the margin.

4.1 Data Base

The data base was collected from qualifying utilities by the Public Power Council (PPC) under the terms of a confidentiality agreement. Under the terms of that agreement, the names of the individual utilities and their industrial customers were deleted from the data base and the names were not publicly disclosed. Furthermore, all parties wishing to evaluate the utility margin data were required to sign confidentiality agreements. All reported utility data reported has been identified by a randomly assigned number. This is essentiality the same way margin data was displayed in the 1985 industrial margin study. The data base consists of cost information from 22 utilities that have an industrial load of at least 3.5 MW. Attachment A displays each utility's percentage of total energy, its inflated and weighted individual margin, and the overall energy-weighted typical industrial margin for all utilities.

4.2 Utility Margins

The individual utility margins are based on categorical costs allocated by the utilities to their industrial customers. The categories of costs include production, transmission, distribution, revenue taxes, and other overhead costs. The data for each of the utilities in the study are included as Attachment B. The total dollar amounts assigned by the utility to each category, divided by the total kWh energy sales to the appropriate industrial class, yields a mills/kWh figure for that cost category. Various costs assigned to the "other" category are added to arrive at each utility's industrial margin.

4.3 Summary of Results

The final results of each step in the margin calculation for each utility are shown in Attachment A. The weighted industrial margin is 0.42 mills/kWh. This margin has been added to the PF-02 energy charges and applied to the forecasted DSI billing determinants.

Attachment A

Utility Code Number	Test Period Energy (KWh)	Total Cost	Production	Transmission	Distribution	Revenue Tax	Other	Weighted Margin
5	712,929,231					1.08	1.53	0.105
6(1)	48,201,600	23.94	17.77	1.09	1.90	3.13	0.04	0.000
6(2)	43,725,600	23.79	17.88	1.12	1.64	3.12	0.05	0.000
6(3)	31,536,000	22.54	16.68	1.61	2.04	4.79	0.06	0.000
7	960,241,000	19.32	13.13	2.42	2.47	1.29	0.00	0.000
9	179,182,000	24.70	22.11	0.00	0.28	1.41	0.90	0.016
11	2,530,665,300					0.03	0.39	0.096
12	147,941,470	27.91	24.91	0.40	0.76	1.71	0.13	0.002
14	177,000,000					0.00	0.00	0.000
15	228,182,000	23.21	19.40	2.26	0.06	1.35	0.14	0.003
17	164,476,000	21.52	19.08	0.70	0.27	1.47	0.01	0.000
18	72,908,253	30.48	23.69	0.88	4.00	1.83	0.08	0.001
20(1)	68,431,943	30.93	21.63	3.08	3.91	2.26	0.05	0.000
20(2)	52,394,949	31.80	21.89	3.27	4.25	2.27	0.11	0.001
20(3)	16,225,958	44.12	24.23	4.50	12.43	2.74	0.23	0.000
21	62,592,735	36.20	26.06	0.00	6.31	2.62	1.20	0.007
22	66,775,400	18.40	13.50	0.60	2.30	1.60	0.40	0.003
23	527,268,530	24.22	21.63	2.44	0.01	0.13	0.01	0.001
24	44,003,299	29.67	27.87	0.39	0.30	1.05	0.07	0.000
25	224,875,000					2.40	0.31	0.007
26	1,618,984,000	24.41	15.66	5.72	0.43	2.61	0.00	0.000
29	20,808,000	29.98	21.67	0.07	7.72	0.51	0.01	0.000
30	804,946,099	33.07	16.43	3.22	8.91	3.27	1.25	0.097
31	178,809,176	48.54	36.91	0.66	8.36	0.99	1.61	0.028
33(1)	433,297,859	33.78	27.67	0.06	5.19	0.34	0.52	0.022
33(2)	84,893,664	28.02	22.91	0.01	3.49	0.19	1.42	0.012
33(3)	38,530,000	21.06	15.85	0.88	0.86	0.34	3.12	0.012
35	821,133,000					0.00	0.07	0.006
Total	10,360,958,066							0.42

Utility Number: #5

Typical peak in 1998 was 79,608 KW and 17,073 KW
for 2 industrial customers - our large industrial rates are
retail based and do not have established rates based on a COSA.

Additional note provided that states:

Total MWh sales for large industrial customer	712,929
Total admin, Taxes and Other Costs	$1,860,000
Taxes included:	$770,700
Admin and Other costs	$1,089,300

Margin	1.53
Revenue Taxes	1.08

Utility Number: #6(1)	Total Industrial Class-31	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased Power	861,913	861,913				
Transmission	45,794	0	45,794	0	0	0
Distribution	35,614	0	0	35,614	0	0
Customer Services	1,793	0	0	0	0	1,793
Conservation Expense	20	0	0	0	0	20
A&G	10,902	0	5,435	5,253	0	214
Taxes	150,975	0	0	0	150,975	0
Depreciation	25,627	0	79	25,548	0	0
Return on plant	29,750	991	1,608	27,145	0	6
Misc, Revenues	17,304	13,593	872	2,807	0	32
Misc. expenses	8,636	7,368	452	799	0	17
	1,153,720	856,678	52,496	91,552	150,975	2,018
Annual MWh Sales	48,202					
Mills/kwh	23.94	17.77	1.09	1.90	3.13	0.04

Utility Number: # 6(2)

	Total Industrial Class-32	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased Power	785,491	785,491	0	0	0	0
Transmission	43,087	0	43,087	0	0	0
Distribution	27,986	0	0	27,986	0	0
Customer Services	1,793	0	0	0	0	1,793
Conservation Expense	20	0	0	0	0	20
A&G	8,675	0	4,653	3,828	0	194
Taxes	136,252	0	0	0	136,252	0
Depreciation	20,121	0	76	20,045	0	0
Return on plant	23,925	1,110	1,521	21,289	0	6
Misc, Revenues	13,725	10,872	718	2,107	0	28
Misc. expenses	6,825	5,892	370	548	0	15
	1,040,450	781,621	48,987	71,590	136,252	2,000
Annual MWh Sales	43,726					
Mills/kwh	23.79	17.88	1.12	1.64	3.12	0.05

Utility Number: # 6(3)

	Total Industrial Class-33	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased Power	532,371	532,371				
Transmission	35,714	0	45,794			
Distribution	18,373	0	0	35,614	0	0
Customer Services	1,793	0	0	0	0	1,793
Conservation Expense	20					20
A&G	5,842	0	5,435	5,253	0	214
Taxes	93,127	0	0	0	150,975	0
Depreciation	13,158	0	79	25,548	0	0
Return on plant	15,166	0	0	0		0
Misc, Revenues	9,069	13,593	872	2,807		32
Misc. expenses	4,470	7,368	452	799		17
	710,965	526,146	50,888	64,407	150,975	2,012
Annual MWh Sales	31,536					
Mills/kwh	22.54	16.68	1.61	2.04	4.79	0.06

Utility Number: #7

	Industrial Class	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased Power	13,510	13,510				
Transmission	2,494	0	2,494			
Distribution	2,545	0	0	2,545	0	
Customer Services	0	0	0	0	0	
Conservation Expense	0					
A&G	0					
Taxes	0	-903	-167	-170	1,240	0
Depreciation	0					
Return on plant	0					
Misc, Revenues	0					
Other	2					2
	18,551	12,607	2,328	2,375	1,240	2
Annual MWh Sales	960					
Mills/kwh	19.32	13.13	2.42	2.47	1.29	0.00

Utility Number: #9

	Total Industrial	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased Power	4,000	4,000				
Transmission	0	0	0			
Distribution	51	0	0	51	0	
Customer Services	0	0	0	0	0	
Conservation Expense	0					
A&G	163					163
Taxes	253				253	
Depreciation	0					
Return on plant	0					
Misc, Revenues	0					
Other	-40	-38		0		-2
	4,426	3,962	0	50	253	161
Annual gWh Sales	179					
Mills/kwh	24.70	22.11	0.00	0.28	1.41	0.90

Utility Number: #11

Schedule 50	Demand (kw/mo)	Energy (KWh)	First 50 MW ($/kw-mth)	Remainder of billing demand	All Firm Energy (mills/kwh)		Total Margin (W/O Taxes)
Customer 1	322,700	2,447,471,000	0.273	0.066	0.25	59,873	931,773
Customer 2	15,000	83,194,300	0.273	0.066	0.25	4,223	65,716
Total	337,700	2,530,665,300				64,096	997,489
						0.03	0.39416

Utility Number: #12

	Total Industrial Class	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased Power	3,381	3,381				
Transmission	21	0	21			
Distribution	78	0	0	78	0	
Customer Accounts Expense	17	0	0	0	0	17
Customer Service & Inform. Exp	297	296	0	0	0	1
A&G	274	266	2	6	0	1
Taxes	253	0	0	0	253	0
Depreciation Expense	89	19	38	31	0	0
Misc Service Revenue	280	276	1	2	0	0
	4,130	3,685	60	113	253	19
Annual MWh Sales	147,941					
Mills/kwh	27.91	24.91	0.40	0.76	1.71	0.13

Utility Number: #14

Customer A

Annual MWh Sales	177,000
Demand (kw)	22,006
COSA Margin	0.00

Customer A has no responsibility for in-lieu-of taxes.

Utility Number: #15

	Total Industrial Class	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased Power	4,426	4,426				
Transmission	381	0	381			
Distribution	10	0	0	10	0	0
A&G	147	0	135	3	0	9
Taxes	308	0	0	0	308	0
Public Purpose Expenditures	24	0	0	0	0	24
	5,296	4,426	516	13	308	33
Annual gWh Sales	228					
Mills/kwh	23.21	19.40	2.26	0.06	1.35	0.14

Utility Number: #17	Total Industrial Class	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased Power	13,734	13,734				
Transmission	491	0	491			
Distribution	12	0	0	12	0	
Customer Services	5	0	0	0	0	5
Conservation Expense						
A&G	10.184	0.000	9.849	0.234	0.000	0.100
Taxes	1,062				1,062	
Debt Service on Delivery System	177			177		
Total Capital Improvement	5			5		
Interest Income	-1	-1	0	0		
Misc Service Revenue	0	0	0	0		0
	15,494	13,733	501	193	1,062	5
Annual gWh Sales	720					
Mills/kwh	21.52	19.08	0.70	0.27	1.47	0.01

Utility Number: #18

	Total Industrial Class	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased Power	2,288	2,288				
Transmission	13		13			
Distribution	99			99		
Customer Services	5					5
Conservation Expense						
A&G	53		6	45		2
Taxes	168				168	
Depreciation Expense	116		25	91		
Total interest expense	86		19	68		
capital expenditures	106		23	83		
Less: Misc revenues	138	114	4	19	0	0
	2,797	2,174	81	367	168	7
Annual gWh Sales	91.75					
Mills/kwh	30.48	23.69	0.88	4.00	1.83	0.08

Utility Number: # 20(1)	Total Industrial #1	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased power expense	1,446,397	1,446,397				
Transmission purch	182,343		182,343			
Transmission maint	22		22			
Total Distribution	37,713			37,713		
Total Customer Service & Info. Exp	1,805					1,805
Total conservation exp	40,326	40,326				
Total A&G	69,451	32,267	779	34,960		1,444
Total O&M Expense	1,778,057	1,518,990	183,144	72,673	0	3,249
Total taxes	154,752				154,752	
Total debt in service	146,272		20,482	125,790		
Total capital improvements	157,689		22,081	135,608		
Less outside funding sources	69,024		9,665	59,359		
Total misc. revenues	51,425	38,805	5,519	7,018		83
Total net rev. requ	2,116,321	1,480,185	210,523	267,694	154,752	3,166
Annual MWh	68,432					
Mills/Kwh	30.93	21.63	3.08	3.91	2.26	0.05

Utility Number: # 20(2)	Total Industrial #2	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased power expense	1,119,986	1,119,986				
Transmission purch	149,310		149,310			
Transmission maint	0	0	0	0	0	0
Total Distribution	32,326	0	0	32,326	0	0
Total Customer Service & Info. Exp	3,309	0	0	0	0	3,309
Total conservation exp	31,429	31,429	0	0	0	0
Total A&G	58,388	25,146	638	29,956	0	2,648
Total O&M Expense	1,394,748	1,176,561	149,948	62,282	0	5,957
Total taxes	118,985	0	0	0	118,985	0
Total debt in service	119,740	0	16,159	103,581	0	0
Total capital improvements	129,090	0	17,421	111,669	0	0
Less outside funding sources	56,504	0	7,625	48,879	0	0
Total misc. revenues	39,713	29,441	4,402	5,722	0	149
Total net rev. requ	1,666,346	1,147,121	171,501	222,932	118,985	5,807
Annual MWh	52,395					
Mills/Kwh	31.80	21.89	3.27	4.25	2.27	0.11

Utility Number: # 20(3)	Total Industrial #3	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased power expense	382,615	382,615				
Transmission purch	66,299		66,299			
Transmission maint	0		0			
Total Distribution	35,526			35,526		
Total Customer Service & Info. Exp	2,106					2,106
Total conservation exp	11,115	11,115				
Total A&G	43,770	32,267	779	34,960		1,444
Total O&M Expense	541,431	402,622	66,568	68,450	0	3,791
Total taxes	44,405				44,405	
Total debt in service	91,095		5,135	85,960	0	0
Total capital improvements	98,207	0	5,536	92,671	0	0
Less outside funding sources	42,986	0	2,423	40,563	0	0
Total misc. revenues	16,201	9,484	1,762	4,865	0	89
Total net rev. requ	715,951	393,138	73,053	201,654	44,405	3,702
Annual MWh	16,226					
Mills/Kwh	44.12	24.23	4.50	12.43	2.74	0.23

Utility Number: #21

	Total Unbundled Cost- Industrial Class	Production	Transmission	Distribution	Revenue Taxes	Other
Total Power Supply & Transm cost	1,724,291	1,724,291				
Total Distribution Expense	151,298			151,298		
Total Customer Accouts Exp	1,770					1,770
Total Customer Serv & Info Expn	49,486					49,486
Total admin & General	111,845	0	0	83,543	0	28,302
Total O&M Expense	2,038,690	1,724,291	0	234,841	0	79,558
Taxes	164,025				164,025	
Debt Service	79,862			79,862		
CIP	102,923			102,923		
Total Revenue Requirement	2,385,500	1,724,291	0	417,626	164,025	79,558
Misc Revenues	119,643	92,866	0	22,492		4,285
Net Revenue requirment	2,265,857	1,631,425	0	395,134	164,025	75,273
Mwh sales	62,593					
Mills/Kwh	36.20	26.06	0.00	6.31	2.62	1.20

Utility Number: #22

	Industrial Class	Production	Transmission	Distribution	Revenue Taxes	Other
Power Resources	22.50	22.50				
Revenue from resale	-9.00	-9.00				
DSM	0.00	0.00				
Transmission	0.60		0.60			
Distribution Service	2.30			2.30		
Other	0.40					0.40
Taxes	1.60				1.60	
Total	18.40	13.50	0.60	2.30	1.60	0.40
Mwh Sales	66,775					

Utility Number: #23	Industrial Customer	Production	Transmission	Distribution	Revenue Taxes	Other
Generation & Energy Supply	11,404,975	11,404,975				
Transmission	411,376		411,376			
Control Area Services	479,709		479,709			
Distribution	1,987			1,987		
Metering & Billing	825					825
Customer Acct Services	164					164
Supervision of Cust Serv & Info	2,693					2,693
General Admin. & Overhead	400,163	0	397,633	887	0	1,643
Taxes	70,470				70,470	
Total	12,772,362	11,404,975	1,288,718	2,874	70,470	5,325
Annual Industrial MWh Sales	527,269					
Mills/kwh	24.22	21.63	2.44	0.01	0.13	0.01

Utility Number: #24

	Total Industrial Class	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased Power	1,371	1,371	-	-	-	-
Transmission Expense	3	-	3	-	-	-
Distribution	6	-	-	6	-	-
Customer Service	3	-	-	-	-	3
A&G	122	121	0	1	-	0
Taxes	46	-	-	-	46	-
Depreciation	130	103	14	13	-	-
Less Misc revenue	374	368	0	6	-	0
	1,306	1,226	17	13	46	3
Annual gWh Sales	44					
Mills/kwh	29.67	27.87	0.39	0.30	1.05	0.07

Utility Number: #25

	Industrial Customer	Revenue Taxes	Other
Customer Charge	$70,440		70,440
State	$211,423	211,423	
City	$327,535	327,535	
	609,398	538,958	70,440
Annual MWh Sales	224,875		
mills/kwh	2.71	2.40	0.31

Utility Number: #26

	Total Industrial Class	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased Power	59,296	47,560	11,735	0	0	0
Distribution	1,207	0	0	1,207	0	0
Taxes	8,457	0	0	0	8,457	0
Net Operating Income	10,088	3,132	6,779	175	1	0
	79,047	50,693	18,514	1,382	8,458	0
Annual gWh Sales	3,238					
Mills/kwh	24.41	15.66	5.72	0.43	2.61	0.00

Utility Number: #29

	Total Industrial Class	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased Power	350	350	0	0	0	0
Transmission						
Distribution	22	0	0	22	0	0
Customer Services	0	0	0	0	0	0
A&G	13	3	0	10	0	0
Taxes	9	0	0	0	9	0
Depreciation Expense	13	0	0	13	0	0
Total interest expense						
Return on Plant(RB)	94	9	1	85	0	0
Less: Misc revenues	1	0	0	1	0	0
	500	361	1	129	9	0
Annual gWh Sales	17					
Mills/kwh	29.98	21.67	0.07	7.72	0.51	0.01

Utility Number: #30

	Total Industrial Class	Productio	ansmissi	istributio	Revenue Taxes	Other
Purchased Power	15,806	15,806	0	0	0	0
Transmission	3,244	0	3,244	0	0	0
Distribution	8,971	0	0	8,971	0	0
Public Purpose Pr(	1,999	741	0	0	0	1,259
Taxes	3,293	0	0	0	3,293	0
	33,313	16,547	3,244	8,971	3,293	1,259
Annual gWh Sales	1,007					
Mills/kwh	33.07	16.43	3.22	8.91	3.27	1.25

Utility Number: #31

	Total Industrial Class	Production	Transmission	Distribution	Revenue Taxes	Other
Purchased Power	6,596	6,596	0	0	0	0
Transmission	48	0	48	0	0	0
Distribution	206	0	0	206	0	0
Customer Services	1	0	0	0	0	1
Conservation Expense						
A&G	478	3	70	405	0	0
Taxes	178	0	0	0	178	0
Depreciation Expense	314	0	0	314	0	0
Total interest expense	571	0	0	571	0	0
Rate Margin	284	0	0	0	0	284
Other	2	0	0	0	0	2
	8,679	6,600	118	1,496	178	288
Annual gWh Sales	179					
Mills/kwh	48.54	36.91	0.66	8.36	0.99	1.61

Utility Number: # 33(1)		Production	Transmission	Distribution	Revenue taxes	Other
Purchase Power	11,803,475	11,803,475				
Transmission	5,902		5,902			
Distribution	848,014			848,014		
Customer Expense	170,170					170,170
Other Pwr supply	132,683	132,683				
Administrative & General	378,041	43,584	0	278,559		55,898
Taxes	147,613				147,613	
Depreciation						
Transmission	11,008		11,008			
Distribution	358,185			358,185		
General Plant	137,699		6,625	131,074		
Other Expenses						
Contract Credits	651,208			651,208		
Other Interest & Deductions	10,415		1,188	9,227		
Subtotal Rev. Requirement	14,654,413	11,979,742	24,723	2,276,267	147,613	226,068
Change in Working Capital	103,835	85,747	177	16,293		1,618
Less: Non Rate Revenue						
Interest income	18,659	15,409	32	2,928		291
Misc Revenue	1,516	1,252	3	238		24
Rents	28,271			28,271		
Late Payment	56,046	46,283	96	8,794		873
Other Expenses	15,266	12,607	26	2,395		238
Total Rev Requirement	14,638,490	11,989,939	24,744	2,249,933	147,613	226,260
Mwh Sales(need this)	433,298					
Mills/Kwh	33.78	27.67	0.06	5.19	0.34	0.52

Utility Number: # 33(2)		Production	Transmission	Distribution	Revenue Taxes	Other
Purchase Power	1,912,929	1,912,929				
Transmission	0		0			
Distribution	64,816			64,816		
Customer Expense	79,767					79,767
Other Pwr supply	20,188	20,188				
Administrative & General	84,497	10,353	0	33,239	0	40,906
Taxes	16,253				16,253	
Depreciation						
Transmission	0					
Distribution	29,792			29,792		
General Plant	11,076		533	10,543		
Other Expenses						
Contract Credits	161,501			161,501		
Other Interest & Deductior	838		96	742		
Subtotal rev requirement	2,381,657	1,943,470	629	300,633	16,253	120,673
Change in Working Capital	16,876	13,866	4	2,145		861
Less: Non Rate Revenue						
Interest income	3,057	2,512	1	389		156
Misc Revenue	248	204	0	32		13
Rents	4,632			4,632		
Late Payment	9,183	7,545	2	1,167		468
Other Expenses	2,501	2,055	1	318		128
Total Rev Requirement	2,378,912	1,945,020	630	296,240	16,253	120,769
Mwh Sales	84,894					
Mills/KWh	28.02	22.91	0.01	3.49	0.19	1.42

Utility Number: # 33(3)		Production	Transmission	Distribution	Revenue Taxes	Other
Purchase Power	575,265	575,265				
Transmission	10,255		10,255			
Distribution	17,291			17,291		
Customer Expense	79,767					79,767
Other Pwr supply	23,457	23,457				
Admin & General	59,913	11,661	0	8,596		39,655
Taxes	13,191				13,191	
Depreciation						
Transmission	19,518		19,518			
Distribution	7,375			7,375		
General Plant	5,855		4,249	1,606		
Other Expenses						
Contract Credits	0			0		
Other Interest & Deductior	744					744
Subtotal rev requirement	812,631	610,383	34,022	34,868	13,191	120,166
Change in Working Capital	5,758	4,396	245	251		866
Less: Non Rate Revenue						
Interest income	1,064	812	45	46		160
Misc Revenue	86	66	4	4		13
Rents	1,613			1,613		86
Late Payment	3,197	2,441	136	139		481
Other Expenses	871	665	37	38		131
Total Rev Requirement	811,558	610,796	34,045	33,278	13,191	120,162
MWh Sales	38,530					
Mills/Kwh	21.06	15.85	0.88	0.86	0.34	3.12

Utility Number: #35

	Total Large Industrial Schedule 36	Production	Transmission	Distribution	Revenue Taxes	Other
Sub-transmission	742,155		742,155			
Primary distribution	0			0		
Secondary distribition	0			0		
Meters and Services	1,456			1,456		
Customer Accounts	6,035					6,035
Customer Service	552					552
Conservation/Public Purpose	814,988	814,988				
Primary distribution	931,517			931,517		
Customer Accounts-Uncollec	19,837					19,837
Sales	34,563					34,563
Total Expenses	2,551,103	814,988	742,155	932,973	0	60,987
Industrial Sales (MWh)	821,133					
Mills/Kwh	3.11	0.99	0.90	1.14	0.00	0.07

APPENDIX B

VALUE OF DSI SUPPLEMENTAL CONTINGENCY RESERVES

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VALUE OF DSI SUPPLEMENTAL CONTINGENCY RESERVES

Section 7(c)(3) of the Northwest Power Act provides that the Administrator shall adjust rates to the DSI customers "to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers." The DSIs may provide two types of reserves: Supplemental Contingency Reserves and Stability Reserves. In the past, these reserves were treated together in a single "Value of Reserves" credit. With the separation of BPA into two business lines and the bifurcation of the power and transmission rate cases, these reserves are being treated separately. Issues concerning Stability Reserves will be addressed in the rate case that will establish transmission rates for FY 2002 through 2006. The BPA PBL's construct for procuring Supplemental Contingency Reserves (Supplemental Reserves) is described below.

The Northwest Power Pool (NWPP) MORC require BPA, as the control area operator, to carry reserves equal to 5 percent of online hydroelectric generation and 7 percent of online non-hydroelectric generation. Up to half of this amount may be Supplemental Reserves, and the remainder must be Spinning Reserves responsive to frequency. Supplemental Reserves are defined as both offline generation fully available within 10 minute notice and interruptible load that can be offline within 10 minutes notice.

Supplemental Reserves is an ancillary service that a transmission provider must offer under the FERC pro forma tariff. This ancillary service is made up of both transmission inputs and generation inputs. As the transmission provider, TBL will procure the generation inputs, and may do so from any entity, including PBL, in order to provide this service. However, establishing a mechanism under which PBL may secure Supplemental Reserves from the DSIs does not preclude TBL from purchasing reserves directly from the DSIs.

At this time, PBL does not anticipate needing to purchase any Supplemental Reserves from DSI customers. In the event that PBL does purchase Supplemental Reserves from a DSI, it will be reflected as an adjustment to the providing customer's IP-02 rate. The level of the credit will be negotiated on an individual customer basis. However, a maximum value that could be reflected in the credit is being proposed. This ceiling is $5.63 kW-month derived from an embedded cost methodology. The details of how this rate was developed can be found in DeClerck *et al*., WP-02-E-BPA-26.

PBL will require any Supplemental Reserves purchased from the DSIs to meet NERC, WSCC, and NWPP criteria:

- The time delay between request for load to be interrupted and the agreed amount of DSI load to go offline, is less than or equal to 5 minutes.

- Once there is system disturbance, the interruptible load must be accessible prior to a request for reserves from other NWPP parties.

- The interruptible load is available to be offline for up to 60 minutes.

In addition to these required characteristics, the additional criteria identified below define when PBL may pay up to the maximum value for Supplemental Reserves. Once the required criteria are met the rate paid to a DSI will be negotiated on an individual customer basis, based on the following criteria:

- The extent to which BPA has discretion regarding when and how to use the product in satisfaction of obligations and in response to a system disturbance.

- Limitations on the number of times or total minutes the product can be utilized.

APPENDIX C

SLICE OF THE SYSTEM PRODUCT

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SLICE OF THE SYSTEM PRODUCT

1. NATURE OF THE SLICE OF THE SYSTEM (SLICE) PRODUCT

Slice is a firm power product that reflects, by formula, the power generating shape of FCRPS resources. Slice purchasers are entitled to a fixed percentage of the energy generated by the FCRPS. Within nonpower operating constraints, Slice purchasers may vary the rate of delivery of energy within the day, week, month, and year to the same extent as BPA. However, Slice purchasers neither purchase, nor lease any ownership or operating rights to the FCRPS. Actual operations and ownership of the resources will continue to be vested in BPA and other Federal agencies.

Slice purchasers' percentage entitlements are set by contract. The maximum percentage available to a Slice purchaser is established by a ratio of each Slice purchaser's annual average net energy requirements to the annual average firm resources of the FCRPS. The Slice product delivered to Slice purchasers at any given time is calculated by multiplying the Slice purchaser's elected percentage by the FCRPS capability at that time. Therefore, the actual MW delivered to the Slice purchaser will vary throughout the year. During certain periods of the year and under certain water conditions, the power delivered will exceed the Slice purchaser's net firm requirements and may, at times, exceed the purchaser's actual firm load. As a consequence, Slice entails a sale of both requirements and surplus power products.

2. ELIGIBILITY AND TERM

Public body and cooperative utility customers are eligible to purchase the Slice product. Contracts covering a purchase of the Slice product will have terms of 10 years, beginning on October 1, 2001.

3. SLICE RESOURCES

The FCRPS resources that support the Slice product will be identified in the Slice contracts. This is referred to as the Slice System and includes adjustment for all nonpower requirements, unit outages, and the net of all energy transactions related to the System Obligations of the FCRPS. The energy transactions related to System Obligations include, but are not limited to, the transactions related to the return of the Canadian Entitlement, and transactions related to the PNCA, Mid-Columbia Hourly Coordination, and the Canadian Non-Treaty Storage Agreement. System Obligations can either decrease or increase the amount of Slice System capability since they include energy transactions into and out of the FCRPS.

4. SLICE REVENUE REQUIREMENT

Slice purchasers will pay a percent of BPA's PBL costs for each percent share of Slice System energy. This results in a price that is not fixed in terms of MW or MWh. The costs to be covered by Slice purchasers, referred to collectively as the Slice Revenue Requirement, are specified in the Slice Product Costing Table on Attachment 1. The Slice Revenue Requirement mirrors the PBL revenue requirement for the FY 2002-2006 rate period. However, Slice purchasers are not responsible for certain PBL costs. The exceptions to the PBL revenue requirement for Slice purchasers are:

- PBL costs of transmitting power, except for those associated with GTAs and System Obligations.
- Power purchase costs, except for Inventory Solution or public purpose resource acquisitions.
- PNRR.

The Slice product is different from other Subscription products in its design and how customers pay for the product. Because of its unique features, certain elements of the Slice Revenue Requirement need additional explanation.

4.1 Depreciation Costs

If BPA chooses to depreciate a cost in the PBL revenue requirement, BPA will depreciate the obligation in the Slice Revenue Requirement. For costs depreciated beyond the term of the Slice contract, Slice purchasers will be treated consistently with other ratepayers. Depreciation standards (*e.g.*, duration of useful life) used for the recovery of capital investments under the Slice contract will be the same as those used by BPA to set power rates generally, and will not change from those used in the development of Attachment 1, Slice Product Costing and True-Up Table, unless BPA adopts a new depreciation study. As necessary, the Slice Revenue Requirement and the Actual Slice Revenue Requirement shall include a Minimum Required Net Revenues component to ensure coverage of annual cash requirements related to amortization and irrigation assistance payments (amortization/irrigation assistance minus total non-cash expenses).

4.2 Inventory Solution

Prior to the beginning of, or during the term of the Slice contract, it is likely that BPA will take steps to increase or supplement the capability of the FCRPS to serve its Subscription obligations. BPA's efforts to supplement the capability of the FCRPS is called system augmentation, which is also referred to as the Inventory Solution. The net costs associated with the Inventory Solution will become an obligation of the Slice purchaser. However, the Slice purchaser will not receive any portion of the additional power. The overall economic effect of the Inventory Solution on the PBL is accounted for by the net cost of additional power purchases.

The estimated costs associated with the Inventory Solution are shown in the Slice Product Costing and True-Up Table on Attachment 1. BPA will true-up to the actual average MW of the Inventory Solution costs after the Subscription contract signing window closes, but the price of the Inventory Solution ($/MWh) will not be subject to the true-up process and will remain as forecast in the 2002 Final Power Rate Proposal.

Slice contracts will exceed the length of the FY 2002-2006 rate period. As a result, there is no way to determine what, if any, Inventory Solution will be necessary for subsequent rate periods.

BPA will set the Slice Revenue Requirement for costs associated with any Inventory Solution in later rate periods in the same or similar manner as BPA treats Subscription Contracts that extend beyond the FY 2002-2006 rate period.

4.3 Physical Upgrades or Adjustments

The cost of any system upgrade or adjustment to an FCRPS resource identified as a Slice resource will be included in the Slice Revenue Requirement.

4.4 Public Purpose Resource Acquisition

The cost of any Public Purpose Resource Acquisition, as defined in the Slice contract will be included in the Slice Revenue Requirement.

4.5 Credits

Any monetary credits or benefits that PBL receives for items in the Slice Revenue Requirement shall be credited to a Slice purchaser's proportionate share of the Slice Revenue Requirement. These may include Treasury credit for PBL's settlement payment to the Colville Tribe, credits resulting from application of Northwest Power Act section 4(h)(10)(c), and FCCF credits. By sharing in such credits, benefits will be shared proportionately by Slice purchasers and BPA's other requirements power purchasers. If BPA receives revenues in payment for fulfilling System Obligations, a proportionate share of those revenues will also be credited against the Slice Revenue Requirement. However, any revenues for fulfilling System Obligations attributable to a FBS Replacement Resource that the Slice purchaser chose not to participate in will not be credited back to that Slice purchaser.

4.6 Exclusions from the Slice Revenue Requirement

4.6.1 Transmission Costs. The costs of transmitting power from FCRPS generation are excluded from the Slice Revenue Requirement, with the exception noted below. The Slice product is an undelivered product and Slice purchasers are responsible for acquiring their own transmission services. However, Slice purchasers are still responsible for costs of transmitting power associated with GTA and System Obligations.

4.6.2 Power Purchase Costs. Power purchase costs are excluded from the Slice Revenue Requirement, except for those for the Inventory Solution or public purpose resource acquisitions. BPA purchases power when its generation is insufficient to meet load. BPA is not required to provide energy in the shape of the Slice purchaser's load because the Slice product is delivered in the same shape as the generation from the Slice system resources. Since BPA makes no purchases to meet its Slice obligations, Slice purchasers are relieved of the obligation to pay for power purchases such as balancing purchases to meet BPA's other firm power load. However, if BPA incurs power purchase costs as part of the Inventory Solution, or acquires a public purpose resource, Slice purchasers are obligated to pay for those costs.

4.6.3 Planned Net Revenues for Risk (PNRR). PNRR are excluded from the Slice Revenue Requirement. PNRR fall into two categories, changes in expenses and changes in revenues (or credits). Changes in BPA's expenses are proportionately shared with the Slice purchaser through an after-the-fact true-up for actual costs. The Slice product eliminates revenue uncertainty by: (a) collecting from Slice purchasers a fixed percentage of BPA's overall PBL revenue requirement that is unrelated to the amount of power delivered; and (b) transferring the risk associated with the variability of water supply and market price risk associated with Secondary Energy Credits to the Slice purchaser.

4.7 Other Risk Mitigation Features

4.7.1 Secondary Energy Credits. Secondary Energy Credits refer to the revenues from secondary energy sales. The portion of the PBL revenue requirement that must be recovered by posted rates is reduced by this and other revenue credits. BPA produces secondary energy on the FCRPS when the PNW water supply exceeds critical water conditions. Slice purchasers receive a proportionate share of secondary energy directly through the Slice product. This enables Slice purchasers to realize the economic benefits of secondary energy on their own and removes the uncertainty of secondary energy revenues from BPA. Since secondary energy is included in the Slice product, the Slice Revenue Requirement is not credited for revenues from BPA's sales of secondary energy.

4.7.2 Cost Recovery Adjustment Claus (CRAC). The CRAC allows BPA to insure that rates applied to the sales of general requirements power meet the financial targets. *See* Revenue Requirement Study, WP-02-FS-BPA-02. If revenues do not meet the specified targets, the CRAC enables BPA to temporarily raise its rates. Slice purchasers, however, will not be subject to the CRAC because they assume the water and market risks associated with secondary energy on their own. In addition, the Slice product contains a periodic true-up for the difference between planned and actual costs. On the other hand, if a Slice purchaser also purchases a separate block power product from BPA, the block will be subject to the CRAC.

5. COST SHIFT STUDY

The Slice product design was intended to avoid cost shifts either to or from the Slice purchasers from or to the customers that do not purchase Slice. BPA performed a Cost Shift Study to evaluate the effectiveness of the product design at eliminating cost shifts under varying water and market conditions. For printout of the Cost Shift Study inputs and results, s*ee* section 4.7 of the Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05B.

5.1 Overview Description of the Cost Shift Study

The Cost Shift Study analyzed the changes to BPA's net revenues between two cases; a Slice case and a non-Slice case. The non-Slice case was a condition where all sales of firm power were assumed to be made as Core Subscription products. The second case, the Slice case, was a condition where 15 percent of BPA's firm and secondary inventory was assumed to be sold under the terms and conditions of the Slice product. BPA calculated the changes to BPA's net revenues between the Slice case and the non-Slice case for a one year period. The changes in net revenues were calculated under 50 historical water conditions, using incremental market prices that would be expected for such water conditions for secondary energy sales and power purchases. The Cost Shift Study assumptions for both cases were consistent with assumptions used for the 2002 Power rate case.

The Cost Shift Study was done in two steps. The first step compared BPA's Subscription revenues from the sale of PF power Subscription products to BPA's Subscription revenues with a portion sold as Slice. This difference in Subscription revenues was independent of water conditions and is referred to as the "direct revenue impact."

The second step examined the difference in BPA's net revenues from sales of secondary energy and the expenses of power purchases under the two cases. The net revenues varied under the two cases because secondary energy delivered to a Slice purchaser is power that BPA otherwise would sell at market prices or use to displace its power purchases. Since these net revenue impacts vary, depending on water conditions, they are referred to as "variable revenue impacts."

There were seven major inputs to the Cost Shift Study. These inputs were:

- Slice Revenue Requirement for the period FY 2002-2006,
- Aggregate HLH and LLH PF load shapes for the year 2002,
- Monthly HLH and LLH hydro generation for 50 historical water years,
- Monthly generation from thermal and miscellaneous resources (non-hydro generation),
- Monthly generation from Federal hydro independents for 50 historical water years,
- BPA's HLH and LLH PF Energy and Demand Charges, and
- Market price (for power) forecast for 2002.

5.2 Estimation of Net Revenue Impacts

First Step, Direct Revenue Impact. The direct revenue impact, associated with 15 percent of BPA's firm inventory, was measured by comparing the expected PF revenues in the non-Slice case with the expected revenues from Slice sales in the Slice case. The revenues from Slice sales were assumed to be 15 percent of the total annual PBL revenue requirement adjusted for certain excluded costs, as described above. The adjusted annual PBL revenue requirement in this Cost Shift Study was $1.70 billion. In order to make the estimated BPA costs consistent between the Slice case and the non-Slice case, BPA's costs in the Slice case were assumed to equal all the costs in the non-Slice case, including PNRR (adjusted to reflect the effect of a CRAC). *See* Mesa *et al.,* WP-02-E-BPA-32. Therefore, BPA's net revenues from Slice sales were increased by 15 percent of the annual adjusted PNRR. This addition to revenues from Slice sales accounts for decreases in BPA's costs (purchasers of the Slice product assume risks directly) and increased revenues from the Slice True-up Adjustment charge.

Second Step, Variable Revenue Impacts. The variable revenue impacts were based on the expected change in revenues from secondary energy sales and the expected change in costs of power purchases between the two cases. The sale of the Slice product produces a fixed revenue stream that does not vary with water conditions. However, the amount of power delivered to a purchaser of the Slice product will vary with water conditions. The variability in the amount of power delivered (Slice Power) will create a variable impact on BPA's revenues and costs.

BPA assumed that, in the absence of Slice, BPA would have supplied an amount of power equal to the Slice purchasers' net requirements and that amount would not have increased when water conditions made secondary energy available. In the absence of Slice, BPA would have sold the secondary energy on the market or used the secondary energy to reduce its power purchases.

In the Slice case, when secondary energy is available, a portion of the secondary energy will go to the Slice purchaser and be unavailable to BPA. Therefore, BPA will experience foregone revenues or increased power purchase costs relative to the non-Slice case, depending upon whether BPA would have been selling power or purchasing power at the time secondary energy becomes available. The effect on net revenues of the foregone sales and foregone reductions to power purchases will vary depending on the water conditions.

The variable revenue impacts were estimated for each month of each water condition. In each month and water condition, the amount of secondary energy that would be available to BPA in the Slice case was compared to the amount that would be available in the non-Slice case. The difference was multiplied by the forecasted market price of power for that month and water condition.

Slice purchasers will have some flexibility to decide the amount of energy they will use in certain months and between diurnal periods. Therefore, BPA assumed that the Slice purchaser decision criteria would be based on maximizing the net revenues. Since this is the same criteria used in the 2002 Power rate case for determining levels of Federal generation, the Slice energy was set to a percentage of these Federal generation levels.

The monthly average, water year-by-water year hydro generation amounts from the 2002 Power rate case were converted into HLH and LLH monthly FCRPS generation using a spreadsheet approximation. The HLH maximum generation was determined first. Then the HLH maximum generation was subtracted from the total energy for the period, resulting in LLH capability. The LLH generation was not allowed to be less than 3,000 MW to approximate minimum generation requirements. The resulting HLH and LLH FCRPS hydro generation was added to non-hydro generation and the total was multiplied by 15 percent to estimate the power delivered to Slice purchasers (Slice power).

The Slice power, calculated in the manner described above, was compared to the estimate of the Slice purchasers' net requirements in the non-Slice case. The difference was the net change in the Federal system firm load for HLH and LLH. This difference, an increase or decrease in Federal system firm load, was multiplied by the incremental market price for each of the 14 monthly periods for each water year, yielding the variable revenue impacts.

5.3 Cost Shift Study Results

Cost Shift Study results are summarized in Attachments 2 through 7. Attachment 2 tabulates the "direct revenue impacts." The decrease in revenues from the lost net requirements sale (shown on the top half of the table) are netted against the increased revenues resulting from the sale of Slice products (shown on the bottom half of the table). Attachment 6 shows the total effects of the direct and variable revenue impacts. The charts in Attachments 3 and 4 show the change in Slice load from the assumed net requirements loads and the assumed market price for two extreme water conditions. The chart in Attachment 3 displays the average load change during the HLH period (with associated market price) while the chart in Attachment 4 displays the average load change and market price during the LLH period. The chart in Attachment 5 shows the net financial impact to BPA (change in BPA's net revenues) resulting from the sale of Slice products. Attachment 7 shows the breakdown of the cost shift results in terms of non-linear cost shifts and cost shifts from revenues.

The benefit (or cost) from each water condition was plotted against its corresponding September through March historical volume at The Dalles Dam, and a best-fit curve was superimposed (*see* Attachment 5). The results are also tabulated in the table in Attachment 6, showing the maximum and minimum values calculated and the average of all 50 water conditions (50-year average).

Attachment 7 shows the breakdown of the $5.7 million cost shift (50-year average) to the Slice purchasers that is also shown in Attachment 6. The cost shift is comprised of: $6.7 million of non-linear cost shifts (line 9) to BPA; and $12.4 million of revenue cost shifts (line 13) to the Slice purchasers. Both are shown in Attachment 7. These cost shifts are both measured relative to the assumed "linear" reduction in BPA's secondary revenues and power purchase costs (line 7). Linear reduction means that, for a 15 percent Slice sale, there would be a 15 percent reduction in both power purchase costs and secondary revenues. The non-linear cost shift occurs when the reduction to BPA's net revenues resulting from changes in secondary revenues and balancing power purchases is greater than the assumed linear effect. A revenue cost shift to BPA occurs when the additional power sales revenues (Fixed Impact on line 12) collected from the Slice product (over the alternative PF revenues from the non-Slice case) are less than the assumed linear effect (Linear Effect on line 11). Since the "Fixed Impact" amount on line 12 is larger than the "Linear Effect" on line 11, the cost shift is positive, indicating a cost shift to Slice purchasers, instead of to BPA.

The non-linear cost shift is a function of the assumed non-Slice load shape, the assumed shape of the Slice load, and the market prices. The non-linear cost shift is very sensitive to changes in any of these three assumptions. The margin of error for the three inputs are enough to eliminate the $5.7 million cost shift to Slice purchasers, or possibly to indicate a cost shift in the other direction to BPA. The revenue cost shift is a function of the assumed non-Slice load shape, which costs are included in the Slice Revenue Requirement, and the amount of the estimated Slice true-up adjustment charge. The revenue cost shift is similarly sensitive to changes in assumptions.

The 50-year average annual net revenue change to BPA is calculated to be a positive $5.7 million. This amount, representing 2.1 percent of the Slice revenues, is considered to be negligible with respect to the hydroregulation study. *See* section 2.3.3 of Loads and Resources Study, WP-02-FS-BPA-01. BPA concludes from the Cost Shift Study that there are no meaningful cost shifts created by the sale of the Slice product.

Sensitivity Analysis. The Cost Shift Study was tested to see if varying the percent Slice assumption would significantly influence the results. The Cost Shift Study was run using percentages of the Federal system generation output sold as Slice products, which varied from 1 percent to 100 percent. All other inputs were held constant, so that the effect of varying the percentages could be isolated. The sensitivity analysis showed that varying the percentages did not have an appreciable effect of the cost shift result. The 50-year average annual change in net revenues did change in proportion to the percent Slice assumed. However, the maximum effect was a gain of $32.8 million (for 100 percent Slice), which is still considered to be negligible with respect to the hydroregulation studies. *See* section 2.3.3 of Loads and Resources Study, WP-02-FS-BPA-01. The $32.8 million gain represents 2.1 percent of BPA's revenues from sales of the Slice product.

ATTACHMENT 1

ATTACHMENT 1

SLICE PRODUCT COSTING AND TRUE-UP TABLE

			A	B	C	D	E	F
1	PBL Costs ($000)	2002-2006	2002	2003	2004	2005	2006	TOTAL
2	GENERATION COSTS	Audited	Projected →					
3	Federal Base System	Actuals						
4	Hydro							
5	Upstream benefits		$ 1,990	$ 2,050	$ 2,111	$ 2,174	$ 2,240	$ 10,565
6	Corps of Engineers O&M		$ 108,000	$ 112,000	$ 112,000	$ 112,000	$ 112,000	$ 556,000
7	Corps Depreciation		$ 73,329	$ 75,497	$ 78,292	$ 81,258	$ 83,620	$ 391,996
8	U.S. Fish & Wildlife O&M		$ 15,400	$ 16,197	$ 16,995	$ 17,892	$ 18,789	$ 85,273
9	Bureau of Reclamation O&M		$ 47,000	$ 48,300	$ 48,300	$ 48,300	$ 48,300	$ 240,200
10	Bureau Depreciation		$ 19,470	$ 20,043	$ 20,535	$ 21,009	$ 21,516	$ 102,573
11	Colville Settlement		$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 80,000
12	Packwood Dam		$ 2,343	$ 2,577	$ 2,835	$ 3,118	$ 3,430	$ 14,301
13	Net Interest Expense		$ 157,914	$ 158,579	$ 166,657	$ 176,226	$ 177,170	$ 836,546
14	**Subtotal**		**$ 441,446**	**$ 451,243**	**$ 463,724**	**$ 477,977**	**$ 483,065**	**$ 2,317,455**
15	Fish and Wildlife							
16	Expense		$ 131,700	$ 138,000	$ 140,100	$ 142,900	$ 144,400	$ 697,100
17	Amortization		$ 19,772	$ 21,842	$ 23,737	$ 25,394	$ 26,407	$ 117,152
18	Net Interest Expense		$ 6,540	$ 6,759	$ 7,181	$ 7,259	$ 7,166	$ 34,905
19	**Subtotal**		**$ 158,012**	**$ 166,601**	**$ 171,018**	**$ 175,553**	**$ 177,973**	**$ 849,157**
20	Trojan							
21	Decommissioning		$ 9,600	$ 4,200	$ 2,600	$ 2,600	$ 2,600	$ 21,600
22	Debt Service		$ 9,947	$ 9,954	$ 9,964	$ 9,989	$ 10,009	$ 49,863
23	**Subtotal**		**$ 19,547**	**$ 14,154**	**$ 12,564**	**$ 12,589**	**$ 12,609**	**$ 71,463**
24	WNP #1							
25	O&M		$ 400	$ 384	$ 384	$ 384	$ 384	$ 1,936
26	Debt Service		$ 177,704	$ 167,856	$ 174,623	$ 167,910	$ 179,992	$ 868,085
27	**Subtotal**		**$ 178,104**	**$ 168,240**	**$ 175,007**	**$ 168,294**	**$ 180,376**	**$ 870,021**
28	WNP #2							
29	O&M/Capital Requirements		$ 154,094	$ 163,824	$ 170,724	$ 173,824	$ 179,824	$ 842,290
30	Debt Service		$ 197,442	$ 244,980	$ 233,624	$ 187,825	$ 211,976	$ 1,075,847
31	**Subtotal**		**$ 351,536**	**$ 408,804**	**$ 404,348**	**$ 361,649**	**$ 391,800**	**$ 1,918,137**
32	WNP #3							
33	Debt Service		$ 153,720	$ 152,993	$ 149,232	$ 149,480	$ 147,836	$ 753,261
34	**Total**		**$ 1,302,364**	**$ 1,362,035**	**$ 1,375,094**	**$ 1,345,542**	**$ 1,393,659**	**$ 6,779,494**
35								
36	New Resources							
37	Idaho Falls		$ 3,740	$ 3,737	$ 3,744	$ 3,754	$ 3,754	$ 18,729
38	Cowlitz		$ 14,914	$ 14,987	$ 15,051	$ 15,123	$ 15,196	$ 75,271
39	Firm Purchased Power		$ 17,723	$ 17,963	$ 18,187	$ 18,435	$ 18,681	$ 90,978
40	Competitive Acquisitions		$ 12,158	$ 12,340	$ 12,526	$ 12,713	$ 12,904	$ 62,642
41	Columbia Hills (CARES)		$ 4,323	$ 4,359	$ 4,397	$ 4,446	$ 4,490	$ 22,015
42	Wheeling Power Purchase		$ 1,242	$ 1,253	$ 1,264	$ 1,275	$ 1,287	$ 6,321
43	Other Acquisitions		$ -	$ -	$ -	$ -	$ -	$ -
44	**Total**		**$ 36,377**	**$ 36,677**	**$ 36,982**	**$ 37,312**	**$ 37,631**	**$ 184,978**
45								
46	Legacy Conservation							
47	Conservation expense		$ 18,201	$ 16,613	$ 16,913	$ 17,313	$ 17,613	$ 86,651
48	Generation Billing Credits		$ 7,934	$ 7,898	$ 7,866	$ 7,834	$ 7,785	$ 39,317
49	Conservation Financing		$ 5,578	$ 5,577	$ 5,577	$ 5,577	$ 5,577	$ 27,886
50	Conservation Amortization		$ 59,337	$ 55,586	$ 47,125	$ 43,179	$ 37,650	$ 242,877
51	Conservation Interest		$ 38,822	$ 39,345	$ 35,237	$ 34,779	$ 32,001	$ 180,184
52	**Subtotal**		**$ 129,872**	**$ 125,019**	**$ 112,718**	**$ 108,681**	**$ 100,626**	**$ 576,915**
53	Energy Services Business		$ 11,663	$ 11,690	$ 11,601	$ 11,475	$ 11,444	$ 57,873
54	Other Generation Costs							
55	BPA Programs							
56	CSRS Pension Expense		$ 27,600	$ 17,550	$ 15,460	$ 13,260	$ 11,600	$ 85,450
57	Power Marketing		$ 16,000	$ 15,700	$ 8,800	$ 6,800	$ 5,000	$ 52,300
58	Power Scheduling		$ 20,900	$ 12,800	$ 12,100	$ 12,800	$ 12,700	$ 71,300
59	Inventory Solution Hedging Activities		$ -	$ -	$ -	$ -	$ -	$ -
60	Generation Oversight		$ 2,964	$ 2,950	$ 3,050	$ 3,050	$ 3,150	$ 15,163
61	Administrative & Support Services		$ 17,350	$ 16,650	$ 16,650	$ 16,650	$ 16,650	$ 83,950
62	Power Planning Council		$ 5,100	$ 5,100	$ 5,100	$ 5,100	$ 5,100	$ 25,500
63	Miscellaneous Depreciation		$ 4,296	$ 4,693	$ 4,383	$ 3,411	$ 2,973	$ 19,756
64	Geothermal Demonstration		$ 15,768	$ 15,768	$ 15,768	$ 15,768	$ 15,768	$ 78,840
65	Renewables		$ 3,091	$ 2,870	$ 2,683	$ 2,551	$ 2,459	$ 13,654
66	Contingency Resources		$ 391	$ 369	$ 317	$ 395	$ 342	$ 1,814
67	Net Interest Expense		$ 406	$ 359	$ 325	$ 312	$ 308	$ 1,710
68	Between Business Line Expense		$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 20,000
69	Other							
70	WNP #3 Plant		$ 3,086	$ 3,169	$ 3,169	$ 3,169	$ 3,169	$ 15,762
71	**Total Other Generation Costs**		**$ 120,952**	**$ 101,978**	**$ 91,795**	**$ 87,256**	**$ 83,218**	**$ 485,199**
72	**Minimum Required Net Revenues**		$ -	$ -	$ -	$ -	$ -	$ -
73	**COSA Table Subtotal**		**$ 1,601,227**	**$ 1,637,398**	**$ 1,628,989**	**$ 1,590,266**	**$ 1,626,578**	**$ 8,084,458**

ATTACHMENT 1 (Continued)

74									
75	Net Residential Exchange Costs		$ -	$ -	$ -	$ -	$ -		$ -
76	Subscription Settlement Costs (900 aMW's in $)		$ 69,725	$ 69,725	$ 69,725	$ 69,725	$ 69,725		$ 348,626
77									
78	Slice Initial Implementation Expenses		$ -	Not applicable	Not applicable	Not applicable	Not applicable		$ -
79	Slice Implementation Expenses		$ -	$ -	$ -	$ -	$ -		$ -
80									
81	CEA Transmission Costs		$ 13,514	$ 17,105	$ 26,685	$ 26,686	$ 26,686		$ 110,675
82	Ancillary and Reserve Service Costs		$ 10,000	$ 10,000	$ 8,000	$ 8,000	$ 8,000		$ 44,000
83	PBL PF Trans. Pass-Through Costs		$ -	$ -	$ -	$ -	$ -		$ -
84	PNCA & NTS Transmission Costs		$ 1,815	$ 1,815	$ 1,815	$ 1,815	$ 1,815		$ 9,075
85	General Transfer Agreement Costs		$ 47,200	$ 47,200	$ 47,200	$ 47,200	$ 47,200		$ 236,000
86									
87	**REVENUE REQUIREMENT CHECK**		**$ 1,743,482**	**$ 1,783,243**	**$ 1,782,414**	**$ 1,743,692**	**$ 1,780,003**	**0**	**$ 8,832,833**
88									
89	PF Conservation and Renewables Credit Costs								$ 95,104
90	IP Conservation and Renewables Credit Costs								$ 31,536
91	RL Conservation and Renewables Credit Costs								$ 21,900
92	LDD		$ 14,000	$ 14,000	$ 14,000	$ 14,000	$ 14,000		$ 70,000
93	S & I Rate Mitigation Costs		$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000		$ 20,000
94	**Non-COSA Table Subtotal**								$ 238,540
95									
96	**Total PBL Revenue Requirement**								**$ 9,071,373**
97									
98	**Revenue Credits ($000)**								
99	Ancillary and Reserve Service Revs.		$ 80,380	$ 80,293	$ 81,127	$ 81,098	$ 81,025		$ 403,924
100	PBL PF Trans. Pass-Through Revs.		$ -	$ -	$ -	$ -	$ -		$ -
101	Canadian Entitlement Credit		$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000		$ 5,000
102									
103	COE & USBR Project Revenues		$ 8,100	$ 8,100	$ 8,100	$ 8,100	$ 8,100		$ 40,500
104	4(h)(10)(c)		$ 88,147	$ 91,007	$ 90,731	$ 92,873	$ 95,177		$ 457,935
105	Colville Credit		$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600		$ 23,000
106	FCCF		$ 51,406	$ 33,261	$ 22,681	$ 16,079	$ 6,899		$ 130,326
107	Sup/Ent Cap; Irr. Pump		$ 938	$ 707	$ 471	$ 471	$ 471		$ 3,059
108	Energy Efficiency Revenues		$ 13,046	$ 13,345	$ 13,345	$ 13,345	$ 13,345		$ 66,426
109	Property Trnfs & Misc.		$ 3,416	$ 3,416	$ 3,416	$ 3,416	$ 3,416		$ 17,080
110									
111	**Total Revenue Credits**								**$ 1,147,249**
112									
113	**Power Revenues Needed**								**$ 7,924,124**
114									
115	Firm System Augmentation (1282 aMWs on average)		$ 322,218	$ 336,766	$ 289,159	$ 323,744	$ 306,070		$ 1,577,958
116	DSI Augmentation (450 aMWs)		$ 113,888	$ 113,888	$ 113,888	$ 113,888	$ 113,888		$ 569,442
117	Conservation Augmentation (20,40,60,80,100 aMW)		$ 5,415	$ 10,831	$ 16,246	$ 21,662	$ 27,077		$ 81,231
118	**Total Cost of Inventory Solution**		**$ 441,522**	**$ 461,485**	**$ 419,294**	**$ 459,294**	**$ 447,036**		**$ 2,228,632**
120									
121	Revenue 1282 aMWs flat, 450 aMWs to DSIs		$ (327,235)	$ (327,235)	$ (327,235)	$ (327,235)	$ (327,235)		$ (1,636,175)
122	**Net Cost of Inventory Solution**		**$ 114,287**	**$ 134,250**	**$ 92,059**	**$ 132,060**	**$ 119,801**		**$ 592,457**
123									
124		($000)							
125	**Annual Slice Revenue Requirement**	**$ 1,703,316**							
126	**Monthly Slice Revenue Requirement**	**$ 141,943**				**Five Year Total**			**$ 8,516,581**
127	**One Percent of Monthly Requirement**	**$ 1,419.43**							
128									

ATTACHMENT 2

ATTACHMENT 2

Direct Annual Revenue Impacts
(revenues from Slice minus decreased Subscription sales)

Assumptions:				
Load Variance Charge /1	$44,789,000			
Total Operating Expense /2	$1,814,274,600			
Revenue Credits /3	$229,449,800			
Net Cost of Inventory Solution /4	$118,491,400			
BPA Revenue Requirement (Slice) /5	$1,703,316,200			
Decreased Subscription Sale				
Effective Demand Charge	$2.01	per KW-Mo		
Effective PF Rate (Energy)	17.36	mills		
Total Annual PF Load	9295733	MW-Hrs		
Annual Demand	14048552	KW-Mo		
PF Revenue - HLH	$114,538,454			
PF Revenue - LLH	$46,861,503			
Demand Revenue	$28,203,080			
Share of Load Variance charge /1	$6,718,350			
Total Subscription Revenues Lost	$196,321,387			
Increased Revenues from Slice				
Slice Percentage				15.0%
Revenue received from Slice /6			$	255,497,430
Additional Net Revenue Adjustment /7			$	19,200,000
Subtotal			$	274,697,430
Net Gain (Loss) of Fixed Revenues /8			$	78,376,043

NOTES (line numbers refer to Slice Product Costing Table)

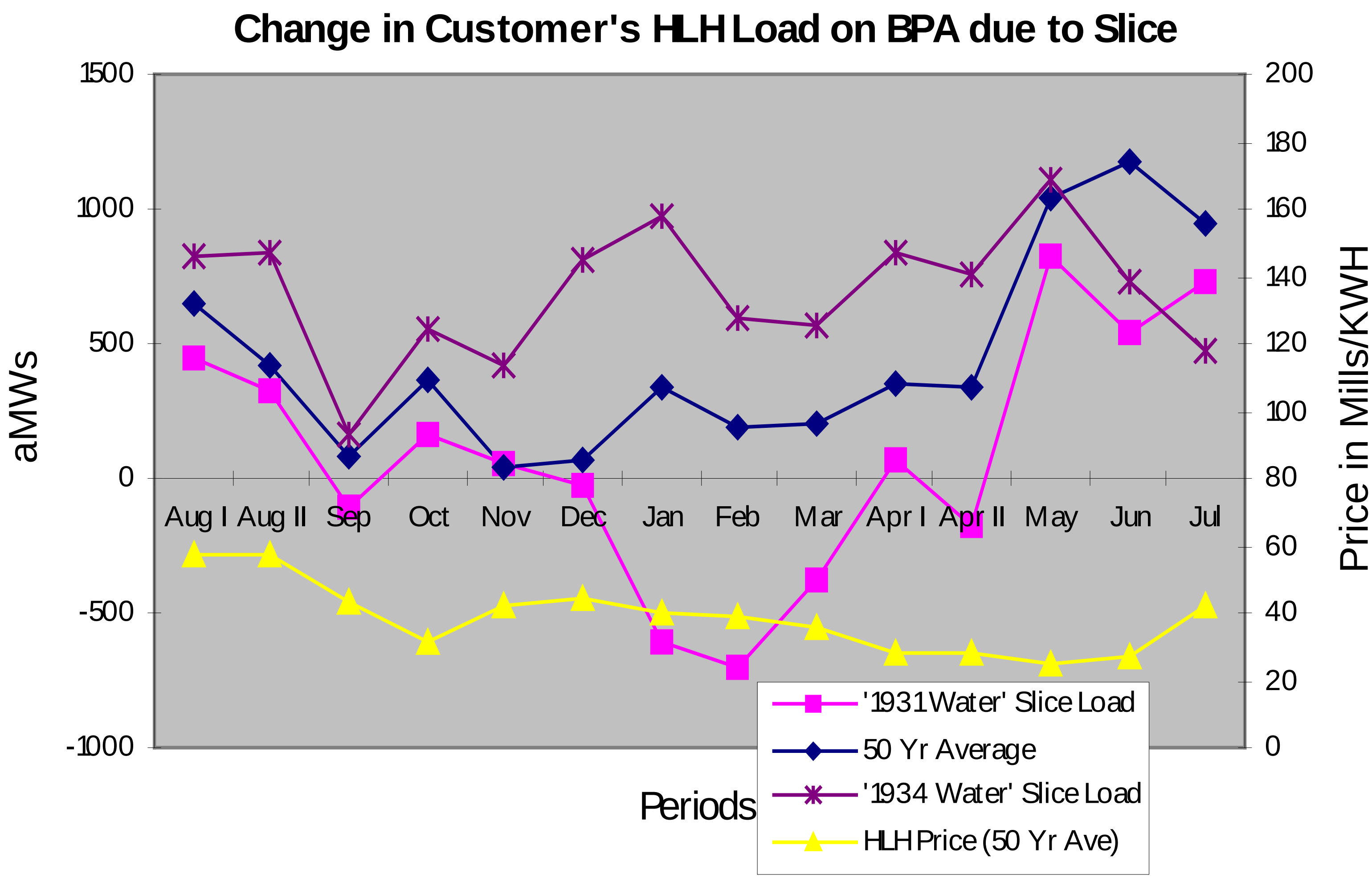
/1 Load variance charge from rate case - included as % Slice chosen in model
/2 Total PBL Revenue Requirement (line 95)
/3 Revenue Credits (line 110)
/4 Net Cost of Inventory Solution (line 120)
/5 Total Operating Expense less Revenue Credits plus Net Cost of Inventory Solution
/6 PBL Slice Revenue Requirement times the Slice percentage chosen in the model
/7 Additional Net Revenue Adjustment is assumed equivalent to planned net revenues for risk
/8 Revenue received from Slice plus Projected True-up less Total Subscription Revenues Lost

Calculation of credit for PNRR & CRAC

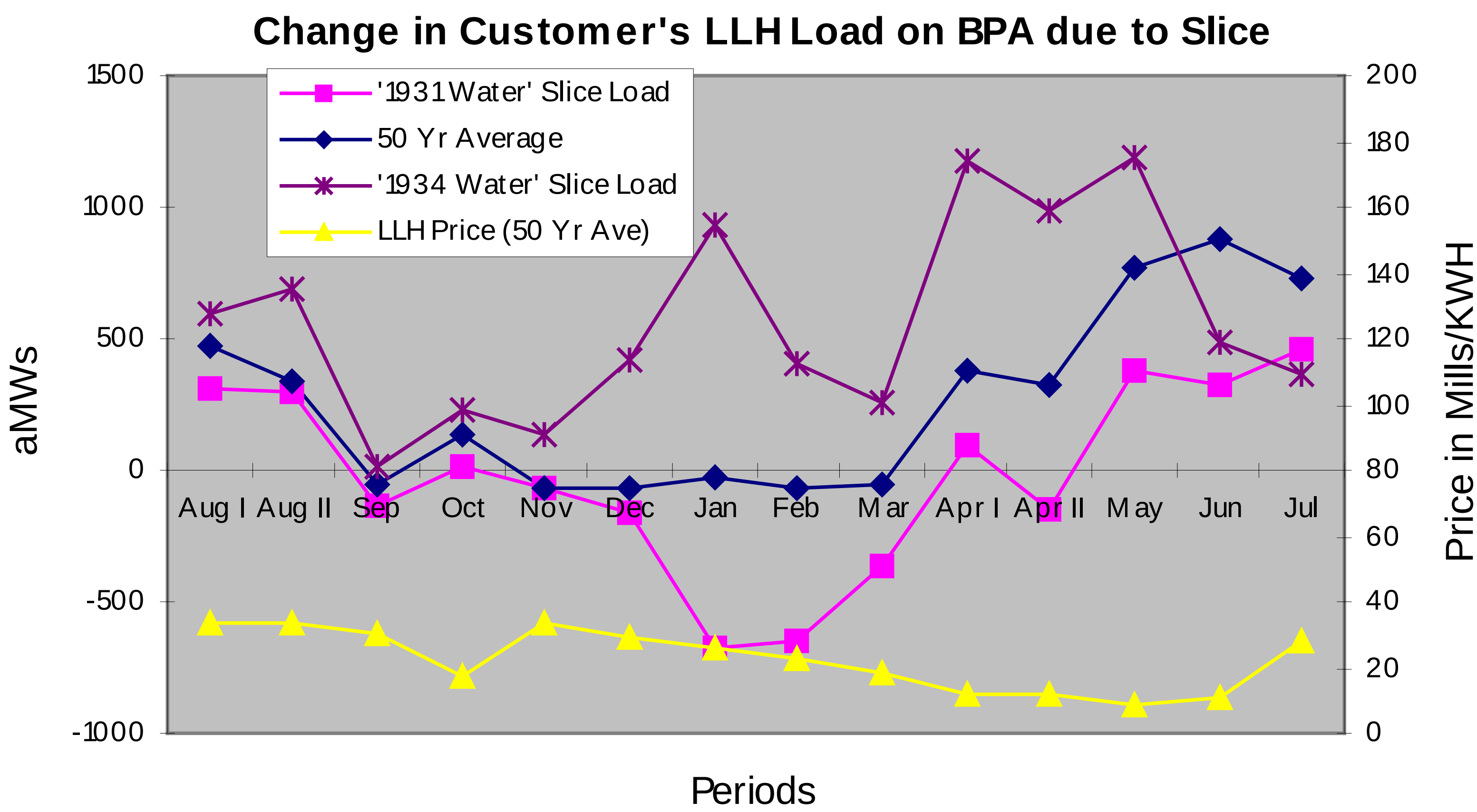
Annual PNRR with no CRAC	$	128,000,000
PNRR Used		100%
PNRR Credited	$	128,000,000

ATTACHMENT 3

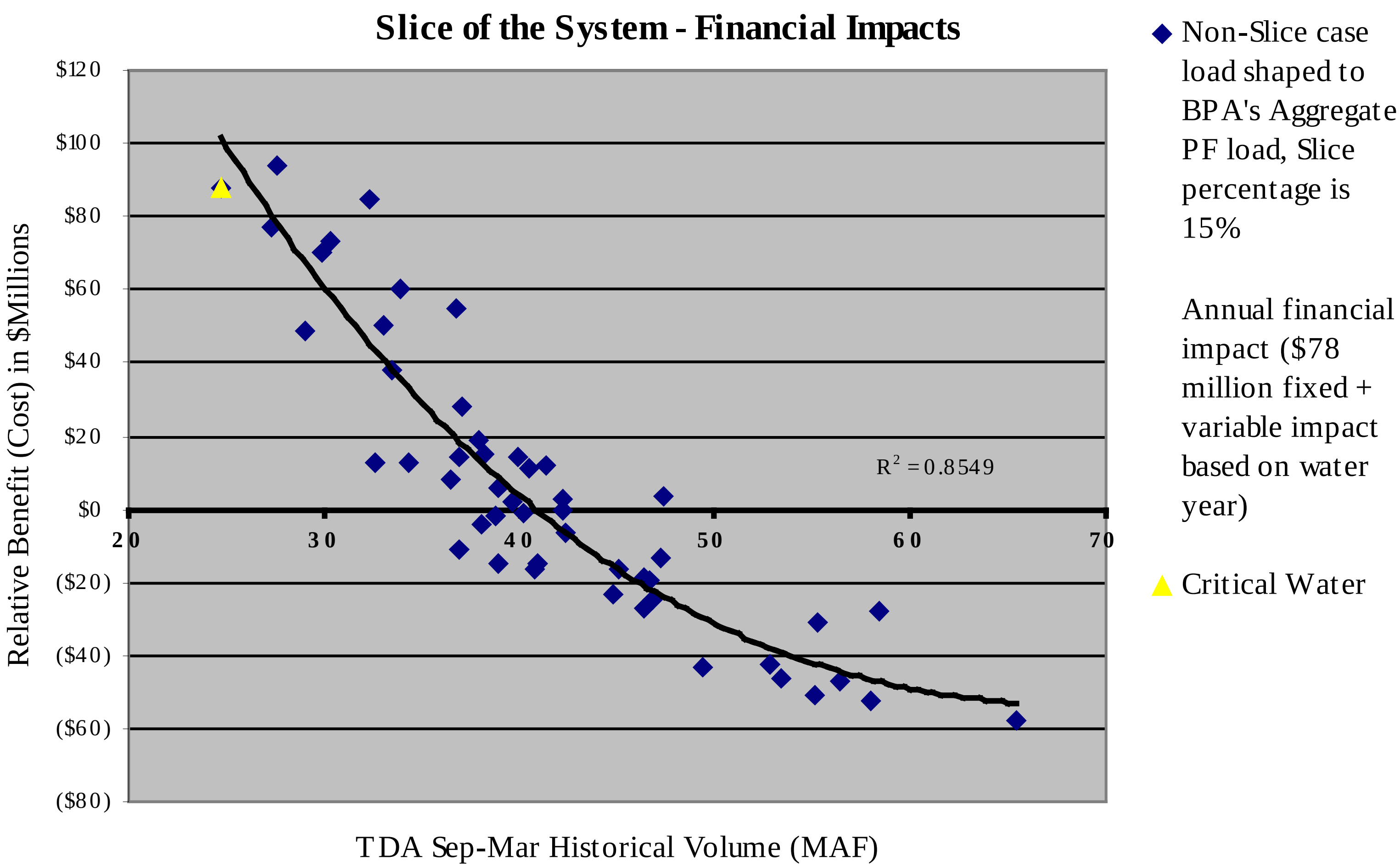
ATTACHMENT 3



ATTACHMENT 4



ATTACHMENT 5



ATTACHMENT 6

	Slice Results over 50 Water Conditions			
	(This uses BPA rate case market price forecasts)	**50 Yr Average**	**Max Value**	**Min Value**
1	Non-Slice case Load (ave MWs)	1061.2	1061.2	1061.2
2	Annual Slice Delivery	1421.7	1787.3	1061.2
3	Maximum Slice Demand	1914.1	2652.7	852.3
4	Maximum Non-Slice Demand	1656.4	1656.4	1656.4
	Change in Net Revenues in $M			
5	Fixed	78.4	78.4	78.4
6	Variable	-72.7	15.5	-136.2
7	Total	5.7	93.9	-57.8
8	Percent of total Slice revenues	2.1%	37%	-23%

Key Assumptions

Loads & Operation:	Non-Slice case load shaped to BPA's Aggregate PF load, Slice percentage is 15%
Impacts Included:	Annual financial impact ($78 million fixed + variable impact based on water year)
Crit. Inventory:	7074 aMWs
Updated:	04/24/2000 by Philip Mesa (503) 230-7390

ATTACHMENT 7

Cost Shift Breakdown for 15% Slice ($Million)			
All results are expressed on an annual average basis			
1	**Rate Case Results**		
2	Secondary Revenues	515.6	
3	Balancing Purchases	-75.4	
4	Net (#2 + #3)	440.2	
5	**Cost Shift Results**		
6	Slice %	15%	
7	Linear Effect (#4 x #6)	-66.0	
8	Variable Impact	-72.7	
9	non-Linear cost shift (#8 - #7)	-6.7	-6.7
10			
11	Linear Effect (#4 x #6)	66.0	
12	Fixed Impact	78.4	
13	Revenue cost shift (#12 - #11)	12.4	12.4
14	50 Yr Ave Cost Shift (#9 + #13)		5.7