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

2002 Wholesale Power Rate Adjustment Proceeding (WP-02)

ADMINISTRATOR'S FINAL RECORD OF DECISION

May 2000

WP-02-A-02

BONNEVILLE
POWER ADMINISTRATION

2002
Record of Decision

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ATTACHMENT

Slice Methodology (for FERC approval for 10 years)

APPENDICES

Appendix 1: 2002 Wholesale Power Rate Schedules

Appendix 2: 1996 Wholesale Power Rate Schedule Adjustment

COMMONLY USED ACRONYMS

AANR	Actual 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
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

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
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)
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.
Idaho Power	Idaho Power Company
IJC	International Joint Commission

IOU	IOU (the joint IOU filings)
IOUs	Investor-Owned Utilities
IP	Industrial Firm Power (rate)
IPTAC	Industrial Firm Power Targeted Adjustment Charge
ISC	Investment Service Coverage
ISO	Independent System Operator
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 (1000 volts)
kW	Kilowatt (1000 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
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
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point to Point
PUD	Public or People's Utility District
Puget	Puget Sound Energy, Inc.
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 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
SPG	Slice Purchasers Group
SS	Share-the-Savings Energy (rate)
STREAM	Short-Term Evaluation and Analysis Model
SUB	Springfield Utility Board
SUMY	Stepped Up Multiyear Block
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
UCUT	Upper Columbia United Tribes
UDC	Utility Distribution Company
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service
Vanalco	Vanalco, Inc.
VB	Visual Basic
VBA	Visual Basic for Applications
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

1.0 INTRODUCTION

This Record of Decision (ROD) contains the decisions of the Bonneville Power Administration (BPA), based on the record compiled in this rate proceeding, with respect to the adoption of power rates for the five-year rate period commencing October 1, 2001, through September 30, 2006. This “2002 Wholesale Power Rate Adjustment Proceeding” is the pricing implementation of BPA’s Power Subscription Strategy adopted December 21, 1998. The Subscription Strategy, as well as other agency processes, provide the policy context for this rate case. This context is described in ROD chapter 2.

This ROD follows a full evidentiary hearing, briefing, and oral argument before the BPA Administrator. Parties had the opportunity to file briefs on exception to the Draft ROD before the Administrator issued the final rate proposal. ROD chapters 3 through 19 present the issues raised by parties to this proceeding, the parties’ positions, BPA’s position on the issues, BPA’s evaluation of the positions, and BPA’s decisions.

1.1 <u>Procedural History of this Rate Proceeding</u>

1.1.1 <u>Issue Workshops</u>

Six months prior to the release of its initial power rate proposal, BPA sponsored workshops on a variety of issues related to its ratemaking. The workshops covered topics ranging from proposed rate designs, revenue requirements, risk management, and inter-business line issues. These workshops were held between BPA and interested parties to develop a common understanding of the issues and to generate ideas and propose alternative solutions to issues in specific areas when possible. Conducting these issue workshops prior to development of the initial power rate proposal enabled BPA to freely exchange ideas and comments relevant to power rates issues with its customers without the restriction of the prohibition on *ex parte* communication which goes into effect prior to the formal rate proceeding. The *ex parte* prohibition went into effect on June 23, 1999, as BPA began development of its initial power rate proposal. The proposal incorporated many of the ideas and solutions arising from these workshops, and this ROD reflects them where appropriate.

1.1.2 <u>Rate Proceeding</u>

Section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. §839e(i) (Northwest Power Act), required that BPA’s wholesale power rates be established according to certain procedures. These procedures include, among other things, issuance of a Federal Register Notice announcing the proposed rates; one or more hearings; the opportunity to submit written views, supporting information, questions, and arguments, and a decision by the Administrator based on the record. This proceeding is governed by BPA’s rules for general rate proceedings contained in the *Procedures Governing Bonneville Power Administration Rate Hearings,* 51 Fed. Reg. 7611 (1986) (hereinafter Procedures). The Procedures implement the section 7(i) requirements.

On August 13, 1999, BPA published its notice of *2002 Proposed Wholesale Power Rate Adjustment, Public Hearing, and Opportunities for Public Review and Comment*, 64 Fed. Reg. 44318 (1999). BPA's 2002 wholesale power rate proceeding began with a prehearing conference on August 24, 1999. At the prehearing conference, the Hearing Officer issued orders concerning procedural matters in this proceeding. On August 30, 1999, the Hearing Officer issued an Order establishing the schedule for this rate proceeding. On September 1, 1999, the Hearing Officer issued an Order concerning data request procedures adopting the electronic discovery procedures proffered by BPA and the parties. On September 2, 1999, the Hearing Officer issued an Order granting in part, and denying in part, petitions to intervene and adopted a service list for BPA's 2002 Wholesale Power Rate Adjustment Proceeding.

BPA's 2002 initial power rate proposal, filed on August 24, 1999, was supported by prefiled written testimony and studies sponsored by approximately 68 witnesses. Oral clarification on BPA's initial power rate proposal occurred from September 13-19, 1999. Direct testimony was filed by the parties on November 2, 1999. Clarification on the parties' direct testimony occurred from November 15-19, 1999. On December 17, 1999, litigants to the proceeding filed testimony in rebuttal to the parties' direct cases. The parties filed their prehearing briefs one week later. Clarification on the litigants' rebuttal testimony occurred from January 4-5, 2000. Written discovery of BPA's and the parties' direct and rebuttal cases occurred throughout the hearing. BPA responded to 1,196 data requests concerning its initial rate proposal and its rebuttal testimony.

Cross-examination took place from January 24, 2000, through February 4, 2000. The parties submitted initial briefs on February 28, 2000. Oral argument before the Administrator was held on March 2, 2000. The Draft ROD was issued and distributed to parties on April 10, 2000. On April 24, 2000, the parties submitted briefs on exceptions in response to the Draft ROD.

This ROD is based on the Administrator's consideration of the entire rate case record, including oral and written comments discussed in ROD section 18.4, *infra*. This ROD was made available on May 15, 2000.

For interested persons who do not wish to become parties to the formal evidentiary hearings, BPA's Procedures provide opportunities to participate in the ratemaking process by submitting oral and written comment. *See* §1010.5 of BPA's Procedures. BPA took oral and written comments at transcribed filed hearings conducted throughout the region between September 30 and October 14, 1999, in eight locations: Idaho Falls, Idaho; Missoula, Montana; Pasco, Spokane, Everett, and Olympia, Washington; and Eugene, and Portland, Oregon. As the result of a public request, BPA held an additional field hearing on November 9, 1999, in Seattle, Washington. BPA received and considered 7,087 written comments submitted during the participant comment period, which officially ended on November 30, 1999. BPA also received written comments after the end of the official comment period and included in the official rate case record those comments received before BPA issued the Draft ROD. The transcribed field hearings and the comments from these rate case participants are part of the record upon which the Administrator bases her decisions.

1.1.3 Waiver of Issues By Failure to Raise in Briefs

While the parties have raised many issues in this proceeding in their briefs, there are a number of issues raised by the parties during the hearing that were not raised in the parties' briefs. Pursuant to §1010.13(b) of the *Procedures Governing BPA Rate Hearings*, arguments not raised in parties' briefs are deemed to be waived. Such issues will be implemented based on BPA's stated position in the record.

1.2 Legal Guidelines Governing Establishment of Rates

1.2.1 Statutory Guidelines

Section 6 of the Bonneville Project Act of 1937 (Project Act), 16 U.S.C. §832e, requires that the Administrator prepare schedules of rates and charges for electric energy sold to purchasers. Under the Project Act, rate schedules become effective upon confirmation and approval by the Federal Power Commission, succeeded by the Federal Energy Regulatory Commission (FERC or Commission). Section 6 of the Project Act directs the Administrator to establish rates with a view to encouraging the widest possible diversified use of electric energy. Section 7 provides that rate schedules are to be established having regard to the recovery of the cost of producing and transmitting electric energy, including amortization of the capital investment over a reasonable period of years. 16 U.S.C. §832f.

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

The Federal Columbia River Transmission System Act of 1974, 16 U.S.C. §838 (Transmission System Act), contains requirements similar to those of the Project Act and the Flood Control Act. Section 9 of the Transmission System Act, 16 U.S.C. §838g, provides that rates shall be established: (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles; (2) with regard to the recovery of the cost of producing and transmitting electric power, including amortization of the capital investment allocated to power over a reasonable period of years; and (3) at levels that produce such additional revenues as may be required to pay when due the principal, premiums, discounts, expenses, and interest in connection with bonds issued under the Transmission System Act. Section 10 of the Transmission System Act, 16 U.S.C. §838h, allows for uniform rates and specifies that the costs of the Federal transmission system be equitably allocated between Federal and non-Federal power utilizing the system.

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

1.2.2 Additional Statutory Guidelines for Inter-Business Line Charges

BPA must satisfy section 212(i) of the Federal Power Act, 16 U.S.C. §824k(i), which states that transmission rates will be governed only by otherwise applicable law, except that no BPA transmission rate applicable to transmission service ordered by the Commission shall be unjust, unreasonable, or unduly discriminatory or preferential as determined by the Commission.

1.2.3 The Broad Ratemaking Discretion Vested in the Administrator

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

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

1.3 Federal Energy Regulatory Commission (FERC) Confirmation and Approval of Rates

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

Energy--Bonneville Power Admin., 23 F.E.R.C. ¶ 61,378, 61,801 (1983). Pursuant to section 7(i)(6) of the Northwest Power Act, 16 U.S.C. §839e(i)(6), FERC has promulgated rules establishing procedures for the approval of BPA rates. 18 C.F.R. Part 300 (1997).

1.3.1 Firm Power Rates

With respect to rates, FERC determines whether: (1) rates are sufficient to assure repayment of the Federal investment in the FCRPS over a reasonable number of years after first meeting BPA's other costs; (2) rates are based on BPA's total system costs; and (3) transmission rates equitably allocate the cost of the Federal transmission system between Federal and non-Federal power using the system. 16 U.S.C. §839e(a)(2). *See United States Department of Energy--Bonneville Power Admin,* 39 F.E.R.C. ¶ 61,078, 61,206 (1987). The limited FERC review of rates permits the Administrator substantial discretion in the design of rates and the allocation of power costs, neither of which is subject to FERC jurisdiction. *Central Lincoln Peoples' Utility District v. Johnson,* 735 F. 2d 1101, 1115 (9th Cir. 1984).

1.3.2 Nonfirm Energy (NF) Rates

Although both regional and extraregional rates are established by the Administrator under common statutory standards, FERC review of extraregional rates for sales of nonfirm energy is undertaken pursuant to section 7(k) of the Northwest Power Act. 16 U.S.C. §839e(k). FERC reviews extraregional nonfirm energy rates to ascertain that BPA has designed the rates: (1) having regard to the recovery of the cost of generation and transmission of such electric energy; (2) so as to encourage the most widespread use of BPA power; (3) to provide the lowest possible rates to consumers consistent with sound business principles; and (4) in a manner that protects the interest of the United States in amortizing its investments in the projects within a reasonable number of years. *United States Department of Energy--Bonneville Power Admin.,* 36 F.E.R.C. ¶ 61,335, 61,798 (1986); *United States Department of Energy--Bonneville Power Admin.,* 54 F.E.R.C. ¶ 61,235, 61,294 (1991).

FERC review of BPA's extraregional nonfirm energy rates is based upon the evidentiary record developed by BPA pursuant to section 7(i) of the Northwest Power Act, 16 U.S.C. §839e(i). *Aluminum Company of America v. Bonneville Power Admin*., 903 F. 2d 585, 592 (9th Cir. 1990). This review is consistent with FERC authority to confirm, reject, or remand BPA's rates. *United States Department of Energy--Bonneville Power Admin.,* 23 F.E.R.C. ¶ 61,378, 61,801 (1983); *Central Lincoln Peoples' Utility District v. Johnson,* 735 F. 2d 1101, 1113 n.6 (9th Cir. 1984).

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

1.3.3 Inter-Business Line Charges

BPA is determining certain inter-business line costs and unit costs that will affect the transmission and ancillary services rates BPA develops in its separate transmission rate proceeding. With respect to transmission and ancillary services rates, BPA must satisfy section 212(i) of the Federal Power Act (FPA), 16 U.S.C. §824k(i), which states that transmission rates will be governed only by otherwise applicable law, except that no BPA transmission rate applicable to transmission service ordered by the Commission shall be unjust, unreasonable, or unduly discriminatory or preferential as determined by the Commission. Section 212(i) does not require the Commission to examine BPA rates under this standard independent of an Order directing BPA to provide transmission service, but the Commission has previously done so upon BPA's request when presented with transmission rates established by the Administrator in a 7(i) proceeding. *See United States Department of Energy--Bonneville Power Admin.*, 80 F.E.R.C. ¶ 61,118, at 61,370 (1997). Presently, BPA will seek a determination by the Commission as to whether the inter-business line charges established in this rate proceeding will allow the Commission to determine whether transmission and ancillary service rates developed in a separate 7(i) process may satisfy the FPA section 212(i) standard. To this end, BPA will encourage the Commission to examine the methodologies used to develop the inter-business line charges and the results obtained and conclude whether the inter-business line charges are not unjust, unreasonable, or unduly discriminatory or preferential.

1.4 Standard of Judicial Review

Section 9(e)(2) of the Northwest Power Act provides that "final determinations regarding rates under section 7 shall be supported by substantial evidence in the rulemaking record required by section 7(i) considered as a whole." 16 U.S.C. §839f(e)(2). In describing the applicable standards of judicial review, the Ninth Circuit has stated that "[t]his court must affirm the rates if 'substantial evidence in the rulemaking record' supports BPA's determination . . . We must also affirm the agency's action unless it is arbitrary, capricious, an abuse of discretion or in excess of statutory authority." *Alcoa v. Bonneville Power Administration*, 891 F. 2d 748, 752 (9th Cir. 1990). *See also*, *Southern California Edison Co. v. Jura*, 909 F. 2d 339, 342 (9th Cir. 1990); *Central Lincoln Peoples' Utility District et al. v. Johnson,* 735 F. 2d 1101, 1115 (9th Cir. 1984).

2.0 OVERALL POLICY CONTEXT

In the Federal Register Notice announcing the 2002 power rate case, BPA described with particularity the nature and scope of the proceeding. 64 Fed. Reg. 44318 (1999). BPA explained that four major public consultation and review processes had been undertaken by BPA in the past five years, and that the rate case would implement policy decisions reached in these processes. *Id*. at 44319-23. The four major public processes referred to are the Business Plan public process, the Cost Review process, the Subscription Strategy process, and the Fish and Wildlife Funding Principles (Principles) process. *Id*. BPA stated that in the power rate case it would not revisit any policy determinations made in any of these processes. *Id*.

In particular, in the case of the Cost Review process, BPA stated that the rate proceeding would not revisit the methodology used to develop the Cost Review recommendations, the policy merits or wisdom of specific recommendations, or BPA's programmatic implementation plans. 64 Fed. Reg. at 44320. In the case of the Subscription Strategy process, BPA directed the Hearing Officer to exclude from the record material which seeks to revisit decisions made in the Subscription Strategy, including the Subscription Strategy ROD. *Id*. at 44322. In the case of the Principles, BPA directed the Hearing Officer to exclude material which attempts to revisit the policy merits or wisdom of the Principles or the strategy to "keep the options open." *Id*. In general, BPA's approach during the rate proceeding was to incorporate the results of these processes, as appropriate, into the rate proceeding and provide the parties the opportunity to evaluate the impact of those determinations on BPA's rates.

In this rate case, BPA has decided the methodologies needed to allocate or assign transmission and generation costs to the power and transmission business lines. Burns and Elizalde, WP-02-E-BPA-08, at 2. BPA continues to recognize the competitive threat posed by the deregulated wholesale electric power market and will therefore continue to assess and undertake actions that will ensure that BPA remains competitive. *Id*. at 4. BPA has undertaken to ensure that its revenue requirements, the repayment schedule, and the risk analysis take into account the full range of potential fish and wildlife costs in implementation of the Principles. *Id.*

2.1 <u>Subscription</u>

2.1.1 <u>The Public Process</u>

A process called "The Comprehensive Review of the Northwest Energy System" was convened in January 1996 by the Governors of Idaho, Montana, Oregon, and Washington to address and resolve many questions regarding the impact of energy deregulation and competition on BPA and the Pacific Northwest (PNW). Subscription ROD, at 1. The Governors appointed a 20-member Steering Committee broadly representative of various stakeholders in the region. The Steering Committee launched a public process that involved more than 100 meetings and various workgroups. The Steering Committee issued a draft report which generated more than 700 written comments. On December 12, 1996, the Steering Committee issued a Final Report. *Id*. at 2.

In its Final Report, the Comprehensive Review recommended that BPA institute a "Subscription-based system" for marketing power and offering new power sales contracts. The Comprehensive Review identified general parameters to guide BPA in this undertaking as well as a priority order among customers for power subscriptions. *Id*. at 1-2.

On February 20, 1997, BPA and the Pacific Northwest Utilities Conference Committee (PNUCC), a consortium of private utilities, public utilities, and industries, invited more than 2,800 interested parties to help define the Subscription Strategy public process. The collaborative effort to design a Subscription Strategy process began with a public meeting on March 11, 1997. At the meeting, a BPA/customer design team presented a proposed work plan, including a description of the National Environmental Policy Act (NEPA) strategy to support this effort. One week later, on March 18, 1997, BPA established a "Federal Power Marketing Subscription" web site to more broadly disseminate information about the Subscription process. *Id*. at 2.

An important element of the Subscription Strategy process was the formation of a Subscription Workgroup. The workgroup meetings were open to the public and scheduled to occur in Portland, twice a month, from March 1997 through September 1998. On average, 40-45 participants attended the meetings, including customers, customer associations, tribes, state governments, and public interest groups. Three subgroups formed to more intensely pursue the resolution of issues involving business relationships, products and services, and implementation. *Id*. at 2.

During the course of these meetings, BPA, its customers, and the other attendees defined issues, proposed product and pricing principles, and developed an implementation process for offering Subscription contracts. On September 18, 1998, following this 18-month public process, BPA issued its draft Subscription Strategy proposal. *Id*. at 3. In response to the draft proposal, BPA received over 200 separate written comments from numerous tribes, state utilities, industries, customers, public interest groups, and citizens. In addition, BPA held two transcribed public meetings to take comment on the draft proposal. *Id*. at 4.

On December 21, 1998, BPA issued the Subscription ROD. The Subscription ROD describes and explains BPA's position on a number of issues. *Id*. at 6. These include the availability of Federal power post-2001; the approach BPA plans to use in selling power by contract with its customers; the products from which customers can choose; and frameworks for pricing and contracts, including risk management. *Id*. at 1. In addition, in the Subscription ROD, BPA stated it was committed to the Principles announced in September 1998 by Vice President Gore. *Id*. at 1.

The four principal goals of BPA's Subscription Strategy are:

(1) To promote the spread of the benefits of the FCRPS as broadly as possible, with special attention given to the residential and rural customers of the region;

(2) To avoid rate increases through a creative and business-like response to markets and additional aggressive cost reductions;

(3) To allow BPA to fulfill its fish and wildlife obligations while assuring a high level of Treasury payment; and

(4) To support BPA's role as being a leader in the regional effort to capture the value of conservation and renewable resources.

Id. at 7.

With respect to providing service to customers, BPA stated in the Subscription ROD that it planned to offer 1,800 average megawatts (aMW) worth of benefits for the residential and small farm consumers of investor-owned utilities (IOUs), after meeting all public agency net firm load requirements. In addition, BPA stated that it expected to meet all loads that direct-service industrial customers (DSIs) asked BPA to serve. 64 Fed. Reg. at 44322.

The Subscription Strategy provides a marketing framework for the power rate case, reflects BPA's position on the equitable distribution of Federal power post-2001, and describes BPA's plan to fulfill its public responsibilities, including the protection of fish and wildlife. However, the Subscription Strategy and ROD did not establish any rates or rate designs. Instead, the Subscription process expressly deferred making such determinations to the instant rate proceeding. Subscription ROD, at 6–7.

2.1.2 Subscription Service to Publics and Investor-Owned Utilities (IOUs)

BPA designed its 2002 rates to implement the four goals of the Subscription Strategy. Burns and Elizalde, WP-02-E-BPA-08, at 7. BPA's rates are designed to promote the spread of benefits of the FCRPS while avoiding increases in average Priority Firm Power (PF) rates. *Id*. BPA will meet the net firm load requirements of its preference customers, offer a combination of power and financial benefits to regional IOUs for the benefit of their residential and small farm consumers, and serve a significant portion of DSI load at competitive rates. *Id*. Second, the 2002 rates fulfill BPA's commitment to the funding range established by the Principles. *Id*. at 8. Third, the 2002 rates also include a conservation and renewables discount (C&R Discount) available to customers purchasing Subscription power that is consistent with the Subscription Strategy. *Id*. The C&R Discount is intended to create incremental efficiency gains and renewable energy supplies, and provide incentives to continue the region's progress in low-income weatherization programs. *Id*. Finally, the 2002 rates include features designed to provide a response to power markets, help manage BPA's costs, and provide customers better information about the costs of their load placement decisions. *Id*.

BPA's public agency customers have criticized implementation of the policy goals of BPA's Power Subscription Strategy in the 2002 rate proposal. The Oregon Utility Resource Coordination Association (OURCA) acknowledges that BPA's power rate proposal is intended to implement the goals described in the Power Subscription ROD of December 21, 1998, including spreading the benefits of the FCRPS as broadly as possible. OURCA Brief, WP-02-B-OU-01, at 1. However, OURCA claims that BPA's rate proposal attempts to implement this goal at the expense of the statutory preference and priority rights accorded to the public preference customers. *Id*. OURCA argues that BPA should compare the cost-based rates to the rates that would apply if the rate test described in section 7(b)(2) were applied. *Id.* at 2. OURCA further states that any agreement for the sale of power to nonpublic preference customers such as the DSIs, settlement of matters such as the Residential Exchange rights of the IOUs, and any administrative determinations involving matters such as the appropriate interpretation of sections 5(b) and 9(c) of the Northwest Power Act are unlawful and void to the extent that they prevent BPA from selling power to the public preference customers at the rates and under the terms described above. *Id.* The Western Public Agencies Group (WPAG) states that the Subscription program that BPA is implementing in this rate proceeding is very different from that which BPA originally proposed to its preference customers. WPAG Brief, WP-02-B-WA-01, at 1. WPAG contends that the growth of the Subscription Program to encompass 3,300 aMW of service commitments to non-preference customers has resulted in BPA taking ratesetting actions that are contrary to its duties under the provisions of the Northwest Power Act, 16 U.S.C. §839, and detrimental to the long-term interests of preference customers. *Id*.

The Public Power Council (PPC), Springfield Utility Board (SUB), Industrial Customers of Northwest Utilities (ICNU), and OURCA argue that sales to BPA's non-preference customers, regional IOUs, and DSIs has come at the expense of BPA's preference customers in the form of charges that may be incurred for Federal service to load placed upon BPA after the Subscription window closes. PPC Brief, WP-02-B-PP-01, at 22; SUB Brief, WP-02-B-SP-01, at 3; ICNU Brief, WP-02-E-B-IN-02, at 6; OURCA Brief, WP-02-B-OU-01, at 1-2. PPC argues that sales to non-preference customers will have the effect of reducing the availability of the Federal Base System (FBS) resources to serve public agency loads. PPC Brief, WP-02-B-PP-01, at 24. PPC states that BPA purchases to supplement the FBS in order to serve public agency loads that arise after September 30, 2000, for service until October 1, 2001, will be treated as FBS replacements. *Id*. As a result, market-based costs that preference agency loads would not otherwise bear will be imposed through a Targeted Adjustment Charge (TAC) and through related "adjustments" and charges for service from the FBS. *Id*. Similarly, ICNU argues that BPA's proposed TAC, Targeted Adjustment Charge for Uncommitted Loads (TACUL), and Stepped-Up Multiyear (SUMY) Block Charge have the economic effect of restricting deliveries of PF power. ICNU Brief, WP-02-B-IN-02, at 7. OURCA and ICNU both discuss the statutory preference that is provided to BPA's public body and cooperative utility customers. ICNU Brief, WP-02-B-IN-02, at 6-10; OURCA Brief, WP-02-B-OU-01, at 1-3. ICNU contends that BPA's proposed rates violate the preference requirements, because they discriminate within preference customer classes and against preference customers in favor of non-preference customers. ICNU Brief, WP-02-B-IN-02, at 6.

BPA is establishing rates that will allow BPA to meet the net firm load requirements of its preference customers, offer a combination of power and financial benefits to regional IOUs for the benefit of their residential and small farm customers, and serve a significant portion of the DSI load at competitive rates. Burns and Elizalde, WP-02-E-BPA-08, at 7. The proposed rates promote the spread of the benefits of the FCRPS while avoiding increases in average PF rates. *Id.* As stated in the Subscription ROD, the lowest cost-based PF rate is available to preference customers that sign contracts in the Subscription window for firm power to meet their regional firm power loads. *Id*. This section 7(i) rate proceeding establishes the rates that will apply to power sales under Subscription contracts. *Id*. The actual amount of power that BPA is obligated to sell to preference customers is determined by contract. Burns and Elizalde, WP-02-E-BPA-37, at 4. In making the PF rate available to its preference customers, BPA is under no obligation to restrict service to IOUs for service to their residential and small farm consumers and DSIs in order to further lower the PF rate. *Id.* Any legal challenges raised by the parties pertaining to any proposed rate are addressed in applicable sections in this ROD. As a matter of policy, BPA's 2002 power rates are in accord with applicable law.

BPA notes that there are no constraints on the supply of Federal power available to preference customers. *Id*. The proposal also includes more flexible power products and power product pricing, including stepped rates applicable to three- and five-year periods, market indexed rates, seasonal pricing, and the TAC. Burns and Elizalde, WP-02-E-BPA-08, at 6. BPA also proposed moving to 12 seasons for pricing both energy and demand. *Id*. This move allows BPA to shape its rates to reflect the relative prices of energy and demand at different times of the year in the west coast power market. *Id.* This will help BPA to manage its costs across years by helping to assure that existing resources are used as efficiently as possible. *Id*. Another means BPA will use to manage its costs is the TAC, which will apply to the customer's applicable rate. *Id*. The TAC is designed to recover the incremental costs BPA incurs to meet these incremental loads. *Id*. at 14. By instituting the TAC, BPA does not have to build additional revenues into the rates for requirements service. *Id*. This additional element will also help to meet BPA's rate stability pledge and spread FCRPS benefits by assuring that loads placed on BPA after the Subscription window closes face the full costs of serving those loads. *Id*.

In contrast to BPA's public agency customers, the IOUs and Portland General Electric (PGE) argue that BPA's rate proposal has not produced an end result that implements BPA's Subscription Strategy goal of spreading the benefits of the FCRPS as broadly as possible by giving special attention to the region's residential and small farm customers. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01 at 5; PGE Brief, WP-02-B-GE-01, at 2. PGE also criticizes BPA's internal rate development process as being fragmented and thus failing to ensure that the end result of the process achieves the agency's goals. *Id*. at 1. The IOUs and PGE also claim that BPA's rate proposal provides 23 percent of the benefits of the FCRPS to the residential and small farm customers of the IOUs, who constitute 60 percent of such customers in the region. *Id.* at 2; WP-02-B-AC/GE/IP/MP/PL/PS-01, at 5. PGE also argues that BPA's process has resulted in a rate proposal that falls short when measured against BPA's policies of promoting conservation and sending market signals to customers that will encourage the economically efficient use of electric power. PGE Brief, WP-02-B-GE-01, at 2.

An important part of spreading the benefits of the FCRPS, with particular attention to residential and rural consumers, involves addressing how such customers within IOU service territories may benefit more directly from the FCRPS. Burns and Elizalde, WP-02-E-BPA-08, at 10. The IOUs and PGE claim that BPA's proposal provides only 23 percent of the benefits of the FCRPS to the residential and small farm consumers of IOUs, who constitute 60 percent of such customers in the region. *Id.* However, implementation of the Subscription goal of spreading the benefits of the FCRPS as broadly as possible, giving special attention to the region's residential and small farm customers, does not depend upon a specific type of a utility. Tr. 180. Rather, BPA is trying to spread the benefits as broadly as possible across the region regardless of the retail utility providing the service. *Id*. at 181. This issue is addressed in greater detail in ROD section 14.1.

With regard to the IOUs, BPA proposes to offer a combination of power and financial benefits to regional IOUs for the benefit of their residential and small farm consumers. Burns and Elizalde, WP-02-E-BPA-08, at 7. BPA's approach to spreading FCRPS benefits provides the IOUs with two options: (1) they may agree to a settlement of the Residential Exchange Program (REP) and purchase some Federal power at a rate approximately equivalent to the PF Preference rate; or (2) they can continue to participate in the Residential Exchange. *Id*. at 10. BPA's Subscription ROD proposed the equivalent of 1,800 aMW of Federal power for the fiscal year (FY) 2002-2006 period, delivered flat annually, assuming the IOUs settle participation in the Residential Exchange. *Id*. at 11. Of the 1,800 aMW, delivered flat, at least 1,000 aMW 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. *Id*. BPA took public comment on whether BPA should increase the proposed settlement amount (1,800 aMW) by 100 aMW. Doubleday *et al*., WP-02-E-BPA-44, at 14. The comment period concluded, and BPA recently released its Power Subscription Strategy Administrator's Supplemental ROD. In that document, BPA reviewed public comments on the issue of whether the IOU settlement amount should be 1,800 aMW or 1,900 aMW. After BPA's review of such comments, BPA determined that 1,900 aMW be proposed as the amount of the IOU Subscription settlement benefits. Subscription Supplemental ROD, at 11-23 (April 26, 2000).

2.1.3 <u>Subscription Service to the Direct Service Industrial Customers (DSIs)</u>

Although BPA stated in the Subscription ROD that it expected to meet DSI loads, BPA also noted that the actual level of service to the DSIs was contingent on the availability of power remaining after the close of the Subscription window. 64 Fed. Reg. at 44322. Subscription ROD at 69-70. The Subscription ROD notes that BPA was not prepared at the time the Subscription ROD was issued to make a number of final decisions, including final decisions regarding augmentation in order to serve DSI load. Subscription ROD, at 70. However, subsequent to the Subscription ROD, BPA developed a proposal for service to the DSIs at a rate above PF, but still at prices well below the projected market prices for power. In the Federal Register Notice announcing this rate case, BPA briefly described this proposal, noting that it would be subject to full consideration in the rate proceeding. As stated in the Federal Register Notice:

> BPA has decided to propose serving approximately 1,440 aMW of DSI load. BPA does not intend to conduct a separate public process to take comments on this proposal. Therefore, parties to the rate case may raise and discuss any issues regarding BPA's proposal to serve the DSIs, including any issues regarding the potential effects of this proposal on BPA's rates.

64. Fed. Reg. at 44322.

Accordingly, while determinations made in the Subscription ROD were expressly excluded from reconsideration in the rate case, the scope of the hearing expressly included BPA's proposal for service to the DSIs.

2.2 Maintaining Stable Rates

Another Subscription goal is to avoid rate increases to the average rates for BPA's public agency customers. PPC expressed a concern that BPA has changed its rate pledge from "two cents in 2000" to one of the four "principle [sic] goals" in the Power Subscription Strategy of "avoiding rate increases through a creative and business-like response to markets and additional aggressive cost reductions." PPC Brief, WP-02-B-PP-01, at 21. PPC argues that BPA claims to "avoid rate increases," but at the same time BPA has increased the amount that BPA customers will pay for power through a variety of rate design techniques. *Id.*

PPC also expressed a concern that cost refunctionalization decreases customers' power bills but shifts a corresponding increase over to customers' transmission bills. PPC Brief, WP-02-B-PP-01, at 22. PPC claims that BPA chooses to ignore the five "adjustments" and charges that attach to PF power sold and are billed to customers, which, PPC claims, BPA must revise or eliminate in order to make good on its pledge. *Id*. PPC argues that BPA adds the C&R Discount to reduce a preference customer's power bill, which adds to the mischaracterization of the PF-02 rates as the unincreased equal to PF-96. *Id*.

BPA's proposed rates are designed to implement the four goals of the Subscription Strategy. Burns and Elizalde, WP-02-E-BPA-08, at 7. BPA's proposed rates promote the spread of the benefits of the FCRPS while avoiding increases in average PF rates. *Id.* BPA proposes to meet the net firm load requirements of its preference customers, offer a combination of power and financial benefits to regional IOUs for the benefit of their residential and small farm consumers, and serve a significant portion of DSI load at competitive rates. *Id.* This proposal also includes a C&R Discount available to customers purchasing Subscription power consistent with the Subscription Strategy. *Id.* at 8. This proposal includes features designed to provide a response to power markets, help manage BPA costs, and provide customers better information about the costs of their load placement decisions. *Id.* These include the following features of this proposal: three- and five-year fixed rate options, moving to 12 seasons for energy and demand pricing, the TAC, cost-based indexed PF rate options, IP rate options, and the Cost Recovery Adjustment Clause (CRAC). *Id.*

The Subscription Strategy goal of no PF rate increase was never intended by BPA to cover items functionalized to transmission, including costs associated with ancillary services. *Id.* at 6. BPA has been functionalizing costs and revenues to generation and transmission for years. *Id.* These practices have been aired and tested in prior rate proceedings and reviewed by FERC. *Id.* The few changes BPA proposed are in response to FERC policies related to the unbundling of transmission and ancillary services from power rates. *Id.* As in previous rate cases, BPA continues to functionalize costs in a manner consistent with jurisdictional utilities. *Id. See* DeWolf *et al.*, WP-02-E-BPA-39, at 46. BPA has not moved costs from power to transmission to achieve the rate goal, and PPC has provided no evidence or support for its contention. *Id.*

2.3 The Fish and Wildlife Funding Principles

On September 21, 1998, Vice President Gore announced that "a new set of principles will enable the BPA to continue providing low-cost power in the PNW while committing necessary funding for salmon restoration in the Columbia River Basin." Revenue Requirement Study Documentation, WP-02-E-BPA-02A, at 358. These Principles were developed following a massive public involvement process that included numerous Federal agencies (including the National Marine Fisheries Service (NMFS), U.S. Fish and Wildlife Service (USFWS), Bureau of Reclamation (Reclamation), U.S. Army Corps of Engineers (COE), and Environmental Protection Agency (EPA)), state agencies, the Northwest Congressional delegation, Columbia Basin tribes, public interest groups, BPA customers, and interested members of the public. 64 Fed. Reg. at 44321.

The public process that culminated in the Principles focused on developing guidelines for structuring BPA's approach to Subscription contracts and BPA's 2002-2006 power rates to ensure that BPA could meet all its financial obligations, including those for fish and wildlife, given hydro conditions, market prices, fish recovery costs, and other uncertainties. *Id*. The Principles specify, among other things, that BPA will take into account the entire range of potential fish and wildlife costs, as reflected in 13 long-term alternatives for configuration of the FCRPS, and treat the alternatives as if each is equally likely to occur. *Id*.

As noted by BPA in the Federal Register Notice announcing the rate case, final decisions and approvals on a fish and wildlife recovery strategy have yet to be made. 64 Fed. Reg. at 44320-21. Because rates are being set before those decisions are made, the driving goal of the Principles is to "keep the options open." *Id*. This is accomplished by taking into account the range of potential costs associated with each hydrosystem configuration alternative. The Principles are intended to ensure that BPA ultimately develops rates and executes power sales contracts that yield a very high probability of BPA meeting all post-FY 2001 financial obligations, including BPA funding obligations for the fish and wildlife recovery strategy that is eventually adopted.

In the Federal Register Notice announcing the rate case, BPA stated it would exclude testimony in the rate case which would, in effect, seek to revisit the merits or wisdom of policy level determinations made in the Principles. As stated in the Federal Register, the Hearing Officer was directed:

> to exclude from the record any material attempted to be submitted or arguments attempted to be made in the hearing which seek in any way to revisit the policy merits or wisdom of the strategy to "keep the options open" or of the Fish and Wildlife Funding Principles. The Principles were developed through extensive public involvement and comment processes and have been adopted as policy at the highest levels of the Administration. The rate proceeding will, however, address implementation of the Principles . . . .

64 Fed. Reg. at 44322.

As discussed more fully in section 5.3, *infra*, policy level determinations and program level costs are not properly subject to a section 7(i) hearing. The reason is that section 7(i) of the Northwest Power Act is applicable to the establishment of rates only, not broad policy determinations that may impact rates. Indeed, the Principles present one of the stronger arguments against subjecting these kinds of costs to a section 7(i) hearing, because section 4(h)(10) of the Northwest Power Act does not contemplate subjecting fish funding program determinations to a section 7(i) hearing. Moreover, given the extensive public process that preceded adoption of the Principles, subjecting these Principles to a second public process--in this case a formal evidentiary hearing--would serve only to undermine the former process, which was necessary to achieve the regional and political consensus needed to move forward in an atmosphere of uncertainty regarding BPA's fish and wildlife obligations.

2.4 Bifurcation of Rate Cases Between Power Business Line and Transmission Business Line/FERC

In setting rates for the period beginning in October 1, 2001, BPA bifurcated its general rate proceeding into separate power and transmission rate proceedings. 64 Fed. Reg. at 44323. BPA voluntarily decided on this approach because it has committed to marketing its power and transmission services in a manner modeled after the regulatory initiatives articulated by FERC in Orders 888 and 889. *Id*. In these orders, FERC directed utilities regulated under the Federal Power Act to "functionally unbundle" power and transmission services, and to establish separate rates for wholesale generation, transmission, and ancillary services. *Id*.

In 1996, consistent with these orders, BPA voluntarily began the process of administratively separating its operations into a Power Business Line (PBL) and a Transmission Business Line (TBL). BPA's PBL is primarily responsible for activities related to the generation and marketing of wholesale power, and BPA's TBL is primarily responsible for activities related to providing transmission and ancillary services. In BPA's initial testimony, BPA explained the reason why separate proceedings for establishing power and transmission rates were necessary. As stated therein:

> The two business lines have different practical needs with regard to rate case timing. BPA's power and transmission rates both expire on October 1, 2001. The Power Business Line (PBL) must establish rates for the post-2001 period now in order to move ahead with the Subscription process. *See* Burns and Elizalde, WP-02-E-BPA-08. However, the Transmission Business Line (TBL) has a number of reasons for deferring the transmission rate case until later in the 1996-2001 rate period. TBL's financial performance during the remainder of the rate period is uncertain, but will affect its financial position at the beginning of the next rate period. TBL's projected costs and sales during the next rate period are uncertain, but more reliable information will be available later in this rate period. Generating adequate revenue to cover costs in an uncertain future will be more feasible with a transmission rate case that is closer to the period for which rates are developed.

Metcalf and Cherry, WP-02-E-BPA-10, at 2.

Moreover, BPA witnesses noted that uncertainty in the transmission environment suggests that a later transmission rate case would be preferable. *Id*. at 3. As a result, TBL issued its initial proposal for the adjustment of rates for transmission and ancillary services on March 15, 2000. 65 Fed. Reg. at 14102.

In the Federal Register Notice announcing initiation of the power rate case, as well as in testimony, BPA described with particularity those issues that would be addressed in the wholesale power rate proceeding and those that would be addressed in the transmission rate proceeding. 64 Fed. Reg. at 44323; Metcalf and Cherry, WP-02-E-BPA-10, at 3-8. In addition, BPA noted that in the power rate case, BPA would decide the appropriate treatment of costs that mutually affect both the power and transmission business lines. The treatment of these inter-business line costs will determine whether the costs are recovered through power, transmission, or ancillary services rates. 64 Fed. Reg. at 44323; Metcalf and Cherry, WP-02-E-BPA-10, at 3-4.

Eugene Water & Electric Board (EWEB) raises a concern regarding the security for net billing agreements. EWEB requests the Administrator to "state in a straightforward way" in this proceeding that power rates will be supplemented with transmission system revenues if needed to meet BPA's third-party debt obligations. EWEB Brief, WP-02-B-EW-01, at 8. EWEB asks BPA to make clear its intent to honor current statutory and contractual obligations that support the security behind the net billing agreements. *Id*. EWEB believes BPA's obligations under the net billing arrangements require that both transmission and power revenues be available to meet BPA's net billed agreement obligations, and that both power and transmission rates should be established to ensure that BPA can meet those obligations. *Id*. at 7. In its brief on exceptions, EWEB states that the Draft ROD "stops short" of addressing its concern and reiterates that "[t]he Administrator should clearly state in the final ROD in this proceeding how conducting separate power and transmission rate proceedings and establishing rates of different lengths will allow BPA to meet FERC approval standards." EWEB Ex. Brief, WP-02-R-EW-01, at 3.

BPA believes that its position taken in the Draft ROD adequately addressed EWEB's concerns. As stated therein, in this rate proceeding BPA has taken into account all net billing costs in setting power rates, as well as all other power function costs. BPA's transmission rates will recover transmission costs. BPA has not identified a need to use transmission rates to recover power function costs, including net billed project costs. The initial 2002 power rate proposal was developed with input from both business lines (PBL and TBL), and both have participated throughout the power rate case. Cherry and Metcalf, WP-02-E-BPA-10, at 6. The proposals and decisions are made by the BPA Administrator, not by either business line. *Id*. In response to EWEB's concern over recovery of BPA's total costs, BPA's policy witnesses testified that "BPA is mindful that its rates, taken in total, must recover BPA's costs, taken in total." Burns and Elizalde, WP-02-E-BPA-37, at 11.

Finally, as EWEB correctly points out, under the Transmission System Act of 1974, to the extent that net billing credits are insufficient to reimburse EWEB for Trojan Project costs, under current law BPA is obligated to reimburse EWEB in cash from the BPA Fund. *See* 16 U.S.C. §838. By law, these cash reimbursements would be paid: (1) from revenues in the BPA Fund, regardless of whether the revenues are derived from the transmission function or the power function; and (2) ahead of BPA payments to the U.S. Treasury. 16 U.S.C. §838k(6). BPA believes that the likelihood of BPA being in a position of being unable to meet a cash requirement under the net billing agreements in the rate period is extremely remote.

3.0 LOADS AND RESOURCES

3.1 Introduction

The Loads and Resources Study represents the compilation of the load and resource data necessary for developing BPA's wholesale power rates. The Loads and Resources Study has three major interrelated components: (1) BPA's Federal system load forecast; (2) BPA's Federal system resource forecast; and (3) the Federal system load and resource balances.

3.2 Federal System Load Forecast

The Federal system load forecast is composed of sales forecasts by customer group for public utilities and Federal agencies, DSIs, IOUs, and other BPA contractual obligations. The public utility and Federal agency sales forecast for this rate case is based on the annual load forecast produced by the Northwest Power Planning Council (NWPPC) in its 1998 Power Plan. BPA split the NWPPC forecast into Full and Partial Service customers, shaped the load to reflect seasonal variation, and estimated peak energy use from load factor data. Loads and Resources Study, WP-02-E-BPA-01, at 3-4. Slice product sales are not separately forecasted; the sale of the Slice product would not increase or decrease the public utility or Federal agency sales forecast. Loads and Resources Study, WP-02-E-BPA-01, at 3-4; Tr. 886, 887, 897. Slice issues are addressed in detail in ROD chapter 16.

The Federal system load forecast includes conservation as part of BPA's system augmentation of resources, as presented in BPA's rebuttal testimony. Oliver *et al.*, WP-02-E-BPA-45, at 8-9. Conservation augmentation is shown as a decrease in system load. *Id.* Loads and Resources Study, WP-02-E-BPA-01.

The IOU sales forecast of 1,000 aMW in actual power deliveries and the DSI sales forecast of 990 aMW for the cost-based portion were based on policy testimony presented in BPA's initial rate case proposal. *See* Loads and Resources Study, WP-02-E-BPA-01, at 5-6. For the final rate proposal, the proportion of heavy load hours (HLH) and light load hours (LLH) for these sales forecasts has been modified from the initial proposal to be consistent with the definition in the Wholesale Power Rate Schedules. This change does not alter the total IOU and DSI sales forecast amounts. Tr. 877. *See* Loads and Resources Study, WP-02-FS-BPA-01.

No party raised issues regarding the Federal system load forecast.

3.3 Federal System Resource Forecast

The Federal system resource forecast includes power generated by both Federal and non-Federal hydro projects, return energy associated with BPA's existing capacity-for-energy exchanges, contracted resources, and other BPA hydro-related contracts. The Federal system hydro resource estimates are derived from a hydroregulation study that estimates generation under 50 water conditions using the operating provisions of the Pacific Northwest Coordination Agreement (PNCA). The seasonal shape and magnitude of the Federal system hydro generation depends on availability of all regional resources and coordination of those resources to meet regional loads. Loads and Resources Study, WP-02-E-BPA-01, at 7.

The Federal system resource forecast has been revised from the initial proposal to reflect an updated hydroregulation study. Tr. 838. Updates to the plant data at four projects and spill levels at two lower Snake River projects have reduced the 50-year average Federal hydro generation by 87 aMW. These updates also reduced Federal hydro generation in critical water conditions (1937 water year) by 145 aMW.

Plant data updates resulted from COE and Reclamation changes to project data made in the Operating Year 2000 PNCA data submittal. These project data changes were made for Grand Coulee, Chief Joseph, McNary, and Bonneville. On average, these project data changes reduce the hydro modeling factors that convert flow to generation and account for about two-thirds of the above stated reductions.

Ice Harbor spill levels in the updated study have been increased due to installation of spill deflectors at the base of the spillway for improved fish passage. These new deflectors allow for higher levels of spill within the Total Dissolved Gas (TDG) limits. The updated study also provides increased spill levels at Lower Granite, because there is operational evidence that spill at higher flows is possible while remaining within TDG limits. These additional spill levels account for the balance of generation reductions.

BPA reviewed the transmission losses presented in the initial proposal. After careful consideration, BPA modified the transmission losses by adding transmission losses for augmentation, imports, and intraregional purchases and removing transmission losses that were inadvertently applied to Federal reserves and maintenance. BPA's treatment of transmission losses in the initial proposal is explained in testimony. Misley *et al*., WP-02-E-BPA-12, at 6. Transmission losses are shown on line 42 of the tables in Appendix B of the Loads and Resources Study, WP-02-E-BPA-01, and on pages 40 through 51 in the Loads and Resources Study Documentation, WP-02-E-BPA-01A. These transmission losses were calculated from the resource amounts in lines 20 (regulated hydro), 21 (independent hydro), 27 (small thermal and misc.), 28 (combustion turbines), 29 (renewables), 33 (large thermal), 34 (nonutility generation), and 35 (resource acquisitions). For the final study, the transmission loss factors are applied to line 37 (total resources) less lines 38 (hydro, small thermal and misc. reserves), 39 (large thermal reserves), 40 (spinning reserves), and 41 (Federal hydro maintenance). Loads and Resources Study, WP-02-FS-BPA-01.

DSI-specific augmentation purchases are required to provide 450 aMW for the DSIs in the Compromise Approach. *See* Berwager *et al*., WP-02-E-BPA-09, and Wholesale Power Rate Development Study, WP-02-E-BPA-05. Transmission losses for the DSI-specific augmentation were not accounted for in the initial proposal. Accounting for these transmission losses results in additional DSI augmentation of 13 aMW for transmission losses associated with the 450 aMW DSI augmentation. Loads and Resources Study, WP-02-FS-BPA-01. An allocation is made in the COSA section of the final Wholesale Power Rate Development Study to account for the 13 aMW transmission losses of DSI-specific augmentation. Wholesale Power Rate Development Study, WP-02-FS-BPA-05.

These updates are incorporated into the final studies and reflect the most accurate estimate available of Federal hydrosystem resources. Loads and Resources Study, WP-02-FS-BPA-01; Loads and Resources Study Documentation, WP-02-FS-BPA-01A.

No party raised issues regarding the Federal system resource forecast.

3.4 Federal System Load and Resource Balances

The projections of Federal system resources are compared with projected Federal system firm loads for each month of Operating Years 2002-2007 (August 2001-July 2007) under 1937 water conditions. The resulting load and resource balances yield the firm energy surplus or deficit of the Federal system resources. Similarly, firm capacity surpluses and deficits are determined for the same period. Load and resource balances were revised to reflect the changes described in the previous sections of this chapter. Loads and Resources Study, WP-02-FS-BPA-01; Loads and Resources Study Documentation, WP-02-FS-BPA-01A.

No party raised issues regarding load and resource balances.

4.0 MARGINAL COST ANALYSIS

4.1 Introduction

The Marginal Cost Analysis (MCA) is used for two purposes in the rate case. First, it is used to inform, but not to directly set, the price level at which BPA buys and sells in the bulk power market. For a complete description of BPA's bulk revenue forecast, *see* BPA's Risk Analysis Study, WP-02-FS-BPA-03. Second, the MCA informs BPA's rate design such that BPA's rates send economic price signals. For example, marginal costs are used as a starting point in deriving the relative levels of the monthly energy rates, and also in deriving the relative levels of HLH energy rates versus LLH energy rates in a given month.

The marginal cost in the MCA is equal to the hourly variable cost of the marginal resource for energy available at the Mid-Columbia (Mid-C) trading hub. The marginal cost is used as an indication of a market-clearing price for hourly bulk energy transactions. Therefore, it is related to the cost that BPA could experience to acquire additional energy, or the price that BPA could realize in selling surplus bulk energy. The actual cost that BPA experiences for bulk power transactions may not be exactly equal to the hourly market clearing price, because BPA may buy or sell a different product than what is traded in an hourly market. In addition, BPA bulk energy transactions may occur at a price not exactly set by the marginal resource in a particular hour. In either case, the hourly marginal cost is related to the market clearing price for bulk energy and is therefore used as a starting point for the price that BPA will experience for hourly bulk energy transactions.

To model marginal costs, BPA used an electric market model called AURORA. AURORA uses an economic fundamentals based approach that models wholesale energy transactions in a competitive pricing system. AURORA uses a demand forecast and supply cost information to find an hourly market clearing price, or equivalently, the marginal cost. To determine the price in a given hour, AURORA models the dispatch of electric generating resources in a least cost order to meet the load (demand) forecast. The price in the given hour is equal to the variable cost of the marginal resource. Over time, AURORA will add new resources and retire old resources based on the net present value of the resource. In this way, AURORA models the functioning of a competitive economic market system.

4.2 The Methodology for Forecasting Resource Additions

Issue 1

Whether BPA's forecast of new generation is reasonable.

Parties' Positions

The Joint DSIs argue that some new resources should be directly input (hardwired) into the generating resource data set. The amount of hardwired resource additions proposed by the DSIs is based on their reading of historical pricing and generation development patterns and an analysis of planned future generation. Schoenbeck and Bliven, WP-02-E-DS/AL/VN-02, at 45-46. "We believe that the increase in market prices over the past three years is evidence of the upswing part of the cycle." *Id*. at 46. "Because market prices have sustained high levels over the past number of months, we believe that the Western Systems Coordinating Council region is at the top of the generator development cycle. The market response will be to a [sic] significant amount of the proposed new generation within the next few years. It is appropriate to include the portion of proposed new generation that has a high likelihood of being constructed prior to the time AURORA would choose based on its perfect foresight." *Id.* at 46-47.

WPAG argues that "BPA should not revise the method by which resources are added to the AURORA model, as proposed by Schoenbeck *et al*." Cross *et al.*, WP-02-E-WA-02, at 37. WPAG notes that the DSIs "propose to impose a resource construction cycle starting in 2000 by adding resources in the early years of the model. This results in a substantial surplus of resources in the rate period, which in turn depresses the forecast average price of energy." *Id.* at 35-36. WPAG argues that the historical pattern was dominated by regulated utilities having an obligation to serve and including capital investments in their rate base. *Id.* at 36. Additionally, generation units were typically large central station units. *Id.* WPAG states that this is not the situation in the current power industry. *Id.* at 36-37. The current situation is driven by independent power producers who make decisions on the amount and timing of new generation based on market factors. *Id.* In addition, generation technology is shifting to smaller, more modular units that can be added in increments that more closely match load growth. *Id.* WPAG concludes, "While the AURORA assumption of perfect foresight in the addition of generating resources does not precisely match up with reality, it is a more accurate depiction of how generating resources are likely to be added to the system during the rate period than that proposed by Schoenbeck *et al*." *Id.* at 37.

<u>BPA's Position</u>

The method used by BPA lets AURORA use standard economic logic to determine the amount and timing of new resources that will be added. Anderson *et al*., WP-02-E-BPA-16, at 2-3; Marginal Cost Analysis Study, WP-02-E-BPA-04, at 4-5; Tr. 1246-48. AURORA's economic logic will add a resource when the return to the resource exceeds its cost. *Id.* AURORA's routine for forecasting new generation was detailed by BPA. Anderson *et al*., WP-02-E-BPA-16, at 2-3; Marginal Cost Analysis Study, WP-02-E-BPA-04, at 4-5; Tr. 1246-48. Furthermore, the parties had ample opportunity to question the use and operation of AURORA. Anderson *et al.*, WP-02-E-BPA-16, at 3-7.

BPA explained its reasons for selecting the economic logic in AURORA instead of the approach proposed by the Joint DSIs. Anderson *et al.*, WP-02-E-BPA-42, at 6-8; Tr. 1286-87. BPA noted that the relevant time period for this forecast was 2002 to 2006, and for this time period, a structural forecast was a reasonable approach. Anderson *et al.*, WP-02-E-BPA-42, at 7. The specifics of forecasting generation development cycles are problematic and introduce a strong possibility of skewing the results. *Id*. The AURORA model produces reasonable results. Tr. 1292.

Evaluation of Positions

There are two fundamentally different methods of forecasting new resources at issue here. The approach used by BPA and supported by WPAG adds new resources based on the economic profitability of resources. Anderson *et al*., WP-02-E-BPA-16, at 2-3; Marginal Cost Analysis Study, WP-02-E-BPA-04, at 4-5; Tr. 1247-48. This method assumes that developers will, on average, respond to economic logic. Marginal Cost Analysis Study, WP-02-E-BPA-04, at 2; Tr. 1248. The method proposed by the Joint DSIs adds new resources based on an exogenous forecast by an analyst. Schoenbeck and Bliven, WP-02-E-DS/AL/VN-02, at 45-49. The amount of new resources proposed by the Joint DSIs was based on a review of cyclical patterns, and a judgment of which planned units would come online and the timing of these units. *Id.*

The Joint DSIs' specific proposal is inextricably bound with their forecast of generation development cycles. Anderson *et al*., WP-02-E-BPA-42, at 6-8. Alcoa/Vanalco assert that this link between pricing and generation cycles and the new generation data the Joint DSIs propose is a BPA "straw man." Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN, at 4-5. However, the conclusion that the Joint DSIs' new generation data and the Joint DSIs' argument for cycles are linked was reached independently by WPAG. WPAG notes that the DSIs "propose to impose a resource construction cycle starting in 2000 by adding resources in the early years of the model. This results in a substantial surplus of resources in the rate period, which in turn depresses the forecast average price of energy." Cross *et al*., WP-02-E-WA-02, at 35-37; Anderson *et al.*, WP-02-E-BPA-42, at 6-8. Alcoa/Vanalco's brief on exceptions ignores this intertwined analysis by arguing for generation additions which were separated from the Joint DSIs' argument favoring cyclical patterns. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 5. This approach was not part of their evidentiary proposal.

The BPA approach is grounded in fundamental economic principles. Even the Joint DSIs concede that AURORA's approach is "an appropriate theoretical treatment." Schoenbeck and Bliven, WP-02-E-DS/AL/VN-02, at 44. It is a reasonable assumption that generation development will follow economic principles. With the Joint DSIs' proposed method, an analyst must independently hardwire in some selected new resources that will be brought online. In this method the analyst uses his or her own judgment or "perfect foresight" as to the amount, timing, and location of new generation that will be built. Tr. 1286-87.

The development of the Joint DSIs' forecast of new generation is prefaced by their arguments for a cyclical generation development pattern. Schoenbeck and Bliven, WP-02-E-DS/AL/VN-02, at 45-49. There are important complexities in forecasting a cyclical generation development pattern. Anderson *et al.*, WP-02-E-BPA-42, at 6-8. The Joint DSIs have not addressed these complexities. *Id.*

The Joint DSIs' forecast is not substantiated by any evidence on the duration, timing, or amplitude of cycles; how other cyclical variables may interact with generation development; or how generation development patterns may evolve in the energy market. *Id.* The lack of substantiation for the future pattern of cyclical generation development undermines the Joint DSIs' exogenous forecast of generation development. *Id.*

Even if the issue is reduced to simply a choice of hardwiring in an exogenous new generation forecast versus letting economic logic internal to AURORA select new generation, the economic logic used by AURORA is a reasonable method to forecast new generation. Anderson *et al*., WP-02-E-BPA-16, at 2-3; Marginal Cost Analysis Study, WP-02-E-BPA-04, at 4-5; Tr. 1246-48; Tr. 1286-87.

Weaknesses in the DSIs' method were also noted by WPAG. WPAG argues that an analysis based on historical patterns is flawed. Cross *et al.*, WP-02-E-WA-02, at 35-37. The nature of both generation developers and generating units is changing. *Id.* at 36. WPAG's argument is persuasive.

The Joint DSIs' specific new generation development forecast is highly speculative. This issue was described in cross-examination of BPA's Marginal Cost Analysis Study panel:

> Q. (Mr. Uda for Alcoa/Vanalco) The question that was pending was whether it was reasonable to expect that the majority of these resources, if completed, would come online in the rate period at issue in this case.
>
> A. (Mr. King for BPA) That depends on how one views the statement "if completed." Clearly if they are completed they would be in service.
>
> Q. So is your answer, then, that these projects, if they followed the normal track, normal construction schedule, would come online during the rate period?
>
> A. (Mr. King) If these projects follow the normal track, very few of these will be completed. And the reason I say that goes back to an earlier question, and that is that in recent years we have not seen necessarily cycles of overbuilding. What we have seen have been cycles of overpermitting. Of the projects that have been permitted in recent years, perhaps the last 10, very, very few have seen construction and even fewer have been completed. And that is the way I view the majority of these projects.
>
> Q. Would that be true just of those that are in the permitting stage or also those that are in the construction stage?
>
> A. (Mr. King) We have seen projects that have been under construction either deferred or terminated.
>
> Q. That was in different markets than we face today?
>
> A. (Mr. King) It was in a market that was evolving towards markets that we are seeing today. Developers and their financiers are extremely cautious in deciding whether to proceed with a project. And having a project permitted is no--is no evidence that that project will see service.

Tr. 1290-91.

The Joint DSIs' data are problematic. The Joint DSIs' data base did not produce results that are verifiable. Anderson *et al.*, WP-02-E-BPA-42, at 2-5. Therefore, the Joint DSIs' data base does not meet a basic standard of credibility. Moreover, when the Joint DSIs' data base is run with AURORA, it produces a result that conflicts with the Joint DSIs' testimony. Cross *et al*., WP-02-E-WA-02, at 32; Tr. 1257-58. This puts BPA in the untenable position of evaluating Joint DSI data that ultimately conflict with the Joint DSIs' own testimony. To fully evaluate the Joint DSIs' data, BPA would have had to decide which to accept as the Joint DSIs' analysis, either their data base or their testimony. The Joint DSIs were asked to reconcile the discrepancy and failed to do so. Anderson *et al.*, WP-02-E-BPA-42, at 3-5. BPA cannot be expected to decide which parts of the Joint DSIs' data base and testimony to accept and which to ignore.

Ultimately, the Joint DSIs' data are not usable because the data base is not verifiable and produces inconsistent results.

BPA's data underlying its forecast of new generation are described in detail in the Marginal Cost Analysis Study Documentation, WP-02-E-BPA-04A, at 2-10, and the Marginal Cost Analysis Study, WP-02-E-BPA-04, at 20-24, 26-31. For reasons described in great detail within this portion of the ROD, BPA's decision meets the appropriate standard of review. *See* ROD section 1.4 and Issue 4, *infra*.

<u>Decision</u>

BPA's forecast of new generation is reasonable. The Joint DSIs' forecast of new generation should not be substituted.

<u>Issue 2</u>

Whether BPA ignored the DSIs' proposal for new resources.

<u>Parties' Positions</u>

Alcoa/Vanalco argue that BPA did not evaluate or include the new generation that the Joint DSIs proposed should be directly input (hardwired) into the new generating resource data set. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 36-44; Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 8, 10.

Alcoa/Vanalco argue that, "when confronted with obvious evidence that generating plants will likely come on line during the rate period (WP-02-E-DS/AL/VN at 46-49), BPA refused to add any exogenous generation to AURORA to allow for more accurate forecasting." Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 5. Alcoa/Vanalco also add a new argument in their brief on exceptions, "BPA should have added generation that BPA knows will come online during the rate period. In fact it is common knowledge that since BPA's AURORA analysis, approximately 1,200 new aMW of generation has come on line in the WSCC. *Market Clearing Prices Under Alternative Resources Scenarios*, California Energy Commission, Appendix C (Feb. 2000)." Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02. Finally, Alcoa/Vanalco argue that BPA's actions were arbitrary and capricious. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 13.

BPA's Position

BPA fully evaluated the Joint DSIs' proposed method for adding new generation. Anderson *et al.*, WP-02-E-BPA-42, at 6-8; Tr. 1256-59; Tr. 1286-87. *See also* Issue 1, *supra*. BPA also noted weaknesses in the development of the Joint DSIs' data on new generation. Anderson *et al.*, WP-02-E-BPA-42, at 7-8. BPA noted that that the Joint DSIs' data base did not produce verifiable results. *Id.* at 2-5. BPA stated that the Joint DSIs' data did not corroborate the Joint DSIs' testimony. Tr. 1257. BPA reasonably rejected the Joint DSIs' proposed generation revision to AURORA.

The introduction of new evidence by Alcoa/Vanalco, *Market Clearing Prices Under Alternative Resources Scenarios*, California Energy Commission, Appendix C (Feb. 2000) at this late stage of the rate proceedings violates the Rate Case Rules of Procedure and should be ignored.

Evaluation of Positions

Alcoa/Vanalco misstate BPA's position on the Joint DSIs' proposal for new generation and draw an erroneous conclusion that BPA failed to consider new generation. BPA stated only that it did not complete an extensive analysis of the amount and timing of the generation proposed by the DSIs. Tr. 1257-60. BPA reviewed the Joint DSIs' proposal and did not adopt the Joint DSIs' data for both methodological and empirical reasons.

First, BPA did not adopt the methodology for hardwiring in new generation proposed by the Joint DSIs. BPA fully stated its reasons for this decision. Tr. 1246-50; Tr. 1286-87; Anderson *et al.*, WP-02-E-BPA-42, at 6-8. BPA fully evaluated the Joint DSIs' proposed method of hardwiring in new generation and compared this to letting the economic logic in AURORA determine the new resource additions. *Id.* at 6-8; Tr. 1246-50. Because BPA chose to use AURORA's internal economic logic for building new resources, it was not necessary to do an extensive analysis of the specific construction and timing that was offered in the Joint DSIs' testimony. In Alcoa/Vanalco's initial brief, an attempt is made to blur the distinction between evaluating the Joint DSIs' proposal on methodological grounds and reviewing the Joint DSIs' data. This distinction was clearly drawn in cross-examination. Tr. 1257-58.

Second, BPA did review and critique the data provided by the Joint DSIs, and BPA found the Joint DSIs' data lacking in substantiation. Anderson *et al.*, WP-02-E-BPA-42, at 7. BPA stated that the Joint DSIs offered no substantive evidence to describe the timing, duration, or amplitude of generation development cycles, nor did the Joint DSIs describe how a cyclical pattern would evolve under electricity restructuring. *Id.* at 7-8. BPA also noted that the amount of new generation proposed by the Joint DSIs is highly speculative. Tr. 1290-91. WPAG also noted weaknesses in the applicability of the data to a forecast of new generation. Cross *et al.*, WP-02-E-WA-02, at 35-37.

Third, BPA clearly stated that the Joint DSIs did not provide a data base that produced verifiable, consistent results. Anderson *et al.*, WP-02-E-BPA-42, at 6-8. Alcoa/Vanalco now admit this infirmity. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 8. Therefore, the Joint DSIs' data are not credible.

Fourth, both WPAG and BPA noted that the Joint DSIs' data base produced results inconsistent with the Joint DSIs' testimony. Cross *et al.*, WP-02-E-WA-02, at 35-37; Tr. 1257-58. The Joint DSIs have failed to reconcile this discrepancy. BPA is not required to unilaterally decide which parts of the Joint DSIs' analysis to select as representing the Joint DSIs' position.

Alcoa/Vanalco attempt to bolster their factual argument in their brief on exceptions by introducing a California Energy Commission document that is not part of the rate case record. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 4. This violates the Rate Case Rules of Procedure, which state that, "All evidentiary arguments in briefs must be based on cited material contained in the record." *Procedures*, §1010.13(a). The document and the argument, which relies on its content, must be rejected. In any case, the document is not dispositive of either BPA's choice not to introduce cycles to its MCA or to include the addition of new generation independent of AURORA's method, because the document and the Alcoa/Vanalco argument do not make BPA's choice to rely on AURORA unreasonable.

Finally, BPA was left to evaluate whether a piecemeal proposal of additional generation by the Joint DSIs (Schoenbeck and Bliven, WP-02-E-DS/AL/VN-02), which Alcoa/Vanalco now characterize as "conservative," is superior to the method for adding new generation that AURORA uses despite the fact that AURORA's approach could be evaluated both methodologically and empirically by BPA and rate case parties. BPA chose to use AURORA's method in its Marginal Cost Analysis. It simply produced reasonable results and was available to all parties, while the Joint DSIs' proposal failed on both counts. This meets the standard for review for this proceeding. *See* ROD section 1.4 and Issue 4, *infra*.

Decision

BPA did not ignore the Joint DSIs' proposal. BPA's response to the DSIs' proposal was reasonable.

Issue 3

Whether BPA arbitrarily and capriciously treated data inputs inconsistently, thereby discrediting BPA's Marginal Cost Analysis.

Parties' Positions

Alcoa/Vanalco argue that BPA treated new generation inconsistently with other data inputs. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 36-44. Alcoa/Vanalco note that BPA arbitrarily changed some data from the default input data base and did not change others, specifically new generation, and claim that the rate case should be recommenced. *Id.* at 42-44. Alcoa/Vanalco complain that BPA did not compare the load forecast used in the MCA to an earlier default forecast that was not used. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 7. They also argue that the MCA is not relevant and reliable due to evidentiary issues. *Id*. at 11.

BPA's Position

BPA fully explained the changes made in the default data base and the reasons for these changes. Marginal Cost Analysis Study Documentation, WP-02-E-BPA-04A. BPA fully detailed the sources of these data and the techniques used to derive its data. Marginal Cost Analysis Study, WP-02-E-BPA-04; Anderson *et al.*, WP-02-E-BPA-16, at 3-7. Alcoa/Vanalco have not established any error or that any error caused the MCA to fail as relevant and reliable evidence.

Evaluation of Positions

Alcoa/Vanalco have raised a new argument in briefs, that changing some data from a default database and not changing other data is a flawed technique. Alcoa/Vanalco have not offered any direct evidence or analysis as to why changing some data, and not others, from a default discredits the reasonableness of the data itself.

Alcoa/Vanalco have treated the data base simplistically and have misunderstood the mechanics of AURORA. Alcoa/Vanalco's argument that all data sets should be treated the same is not valid. The data that Alcoa/Vanalco describe as inconsistent represent fundamentally different phenomena. To insist on consistency for fundamentally different phenomena is overly simplistic.

Alcoa/Vanalco allege that BPA was in error because it treated data inputs for loads, gas prices, hydroelectricity, and new resources differently. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 36-44. Alcoa/Vanalco reveal a fundamental misunderstanding of the mechanics of AURORA. AURORA requires a direct, exogenous forecast of loads and gas prices. For new generation, AURORA has an internal logical routine based on standard economic logic to derive a forecast. Marginal Cost Analysis Study, WP-02-E-BPA-04, at 4-5. Unlike loads and gas prices, there is no new generation default input data base with a forecast of new plants for BPA to change or not change.

Alcoa/Vanalco's misunderstanding appears to be the basis for other factually incorrect statements. For example, Alcoa/Vanalco state, "The relationship between market prices and the construction of new resources is seen in the real world power market but not in the world of the AURORA model because the model assumes perfect knowledge and it only "builds" enough new generation to maintain a stable price." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 37. This statement contains two factual errors.

First, Alcoa/Vanalco are wrong to state that the relationship between market prices and the construction of new resources is not seen in AURORA. *Id.* There is a direct relationship between market prices and the construction of new resources in AURORA. Marginal Cost Analysis Study, WP-02-E-BPA-04, at 4-5. The forecast of market prices drives new construction, and the amount of new construction directly affects market prices. *Id.* This relationship requires AURORA to use an iterative process to solve for the amount of new construction and market prices. *Id.* The bulk of AURORA's running time is in solving precisely this issue, the direct relationship of market prices and new construction.

Second, Alcoa/Vanalco are wrong to state that AURORA will build only enough generation to maintain a *stable* price. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 37 (emphasis added). AURORA will build resources whenever the resource's revenues exceed its costs. Marginal Cost Analysis Study, WP-02-E-BPA-04, at 4-5. AURORA's long-term price forecast will gravitate toward the fully allocated cost of the long-term marginal resource. *Id.* at 2. However, there is no inherent reason that a cost of marginal resources in the long run must be "stable"; it depends on the specifics of the evolving market. To state that AURORA builds only enough resources to maintain a stable price is simplistic and wrong.

Alcoa/Vanalco argue, "AURORA's inaccurate modeling for when new generation comes online led it to incorrectly conclude that generation addition would have no discernible effect on market prices in the rate period." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 39. This statement is wrong. BPA makes no such conclusion. BPA realizes that new generation will affect market prices. BPA stated, "The market clearing price will affect the revenues any particular resource will receive, and consequently which resources are added and retired. In parallel, changes in the resource portfolio will change the supply cost structure and will therefore, affect the market clearing price. AURORA uses an iterative process to address this interdependency." Marginal Cost Analysis Study, WP-02-E-BPA-04, at 4-5. Alcoa/Vanalco seem to confuse the movement toward an equilibrium price with new construction having no effect on price. BPA did not make this mistake.

The DSIs' argument that BPA did not compare the load forecast in the MCA to the default forecast misses the point. BPA fully documented its load forecast. Marginal Cost Analysis Study, WP-02-E-BPA-04, at 6-9. Though not required to, BPA compared the forecast it used in the Marginal Cost Analysis to both historical data and to a load forecast completed by the WSCC in the interest of documenting and fully explaining its inputs. *Id*.

Alcoa/Vanalco waived any argument regarding the evaluation of the evidence, since the testimony was not challenged as required by the rate case rules. *Procedures Governing Bonneville Power Admin. Rate Hearings*, §1010.11(d) and §1010.13(d). They did not object to the qualifications of the panel, the introduction of the Marginal Cost Analysis Study, WP-02-E-BPA-04, and Marginal Cost Analysis Study Documentation, WP-02-E-BPA-04A, or the oral (Tr. 1222-97) and written testimony (Anderson *et al.*, WP-02-E-BPA-16) at the hearing. The MCA and its supporting evidence represent a reasoned and scientifically valid evaluation of BPA's future costs for this rate proposal by BPA staff, and they reflect the input of Alcoa/Vanalco, the Joint DSIs, and other parties. *See, also*, Issues 1-2, *supra*.

In summary, Alcoa/Vanalco's allegation of inconsistent treatment of input data is irrelevant. The mere observation that some data are changed from defaults and some data are not is a trivial fact and irrelevant to the reasonableness of the data. Alcoa/Vanalco's argument for consistency of fundamentally different data is simplistic and misunderstands both the data and the mechanics of AURORA. While more accurate information usually produces better results, it does not follow that BPA's treatment of the Joint DSIs' data in this case ignored this general rule. BPA chose to rely on AURORA's mechanism for predicting the addition of generation resources. BPA's action meets the appropriate standard of review. *See* ROD section 1.4.

Decision

The observation that BPA changed some data from a default data base and did not change other data is irrelevant. Therefore, it does not discredit the reasonableness of the MCA. BPA's testimony and evidence regarding the MCA will not be disregarded, and the rate case will not be recommenced.

5.0 REVENUE REQUIREMENTS

5.1 Introduction

BPA is a self-financed power marketing agency within the Department of Energy (DOE). Sales of electric power and transmission services provide BPA's primary sources of revenue. *See Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1116 (9^{th} Cir. 1984). BPA's power and transmission rates must produce revenues sufficient to assure repayment of all Federal investments in the FCRPS over a reasonable number of years after first meeting the Administrator's other costs. 16 U.S.C. §832g and §839e(a). At the same time, BPA must set rates with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles. 16 U.S.C. §839(a)(1). This rate case has designed wholesale power rates to recover the costs of the generation function only. The rate case did not propose rates to recover the costs of the transmission function (transmission and ancillary services). The Revenue Requirement Study, WP-02-E-BPA-02, for generation determines the level of revenue required to recover all costs of producing, acquiring, marketing, and conserving electric power, including the repayment of the Federal investment in hydro generation, fish and wildlife recovery, and conservation; Federal agencies' operations and maintenance (O&M) expenses allocated to power; capitalized contract expenses associated with such non-Federal power suppliers as Energy Northwest (formerly known as Washington Public Power Supply System); other purchase power expenses, such as system augmentation and balancing power purchases; power marketing expenses; cost to the PBL, if necessary, of transmission services; and all other generation-related costs incurred by the Administrator pursuant to law. *See* Revenue Requirement Study, WP-02-E-BPA-02.

5.2 Revenue Requirement Development

BPA has developed the revenue requirements in conformance with the financial, accounting, and ratemaking requirements of DOE's Order No. RA 6120.2. BPA determines revenue requirements separately for generation and transmission. *United States Department of Energy-Bonneville Power Admin.*, 26 FERC ¶ 61,096 (1984).

The revenue requirements were developed using a cost accounting analysis comprised of three components:

- Repayment studies to determine the schedule of amortization payments and to project annual interest expense for bonds and appropriations that fund the Federal investment in hydro, fish and wildlife recovery, conservation, and associated assets. Repayment studies are conducted for each year of the five-year rate test period, and include a 50-year repayment period.

- Operating expenses and minimum required net revenues for each year of the rate test period.

- Annual planned net revenue for risk (PNRR) based on the risks identified and quantified, the Treasury Payment Probability (TPP) goal, and other risk mitigation tools.

With these three parts, revenue requirements are set at the lowest revenue level necessary to fulfill cost-recovery requirements and objectives.

Normally, BPA conducts a current revenue test to determine whether revenues projected from current rates can meet cost recovery requirements. However, BPA's Subscription Strategy is driving a substantial restructuring of power products and services; BPA is not revising its power rates because current rates are insufficient to recover costs. A current revenue test would be excessively complicated and not meaningful or relevant. Accordingly, a current revenue test is not performed for this rate case. Revenue Requirement Study, WP-02-E-BPA-02, at 43.

BPA is required to demonstrate that projected revenues from proposed rates will meet cost recovery requirements and objectives for the rate test and repayment periods. In this proceeding, rate test period costs are indeed demonstrated to be recovered with a very high confidence level. Risks have been quantified and analyzed, and risk mitigation measures designed to achieve an 88 percent probability that planned payments to Treasury will be recovered on time and in full over the five-year period. Additionally, cost recovery over the 50-year repayment period is fully demonstrated. *Id*.

5.3 <u>Spending Level Development</u>

5.3.1 <u>Cost Review</u>

Development of spending levels in these revenue requirements has its beginnings in the Comprehensive Review of the Northwest Energy Systems (Comprehensive Review), which the Governors of Idaho, Montana, Oregon, and Washington initiated in 1996 to seize opportunities and moderate risks presented by the transition of the region's power system to a more competitive electricity market. *See also* ROD Chapter 2, section 2.1.1, *supra*. The Comprehensive Review recognized that this transition raised fundamental issues for BPA, including long-term competitiveness and risks, with much of BPA's firm revenues at stake due to expiration of long-term power contracts at the end of FY 2001.

A theme of the Comprehensive Review was that BPA and the other entities of the FCRPS must effectively manage and control costs. The recommendations specifically called on BPA to "pursue all actions possible in the short-term to cut costs." Comprehensive Review of the Northwest Energy System Final Report (December 12, 1996), at 18. This was seen as essential to making the proposed Subscription-based system for marketing Federal power successful. A successful Subscription was viewed as the most certain means of achieving the goals of the Comprehensive Review, which were: adding no risk for the U.S. Treasury and third-party bondholders; fulfilling responsibilities for funding fish and wildlife recovery; and retaining the substantial long-term benefits of the FCRPS for the Northwest. Revenue Requirement Study, WP-02-E-BPA-02, at 10.

An outgrowth of the Comprehensive Review was the Cost Review of the FCRPS (Cost Review). In September 1997, BPA and the NWPPC jointly launched a review of FCRPS costs. The objectives of the Cost Review were to ensure that BPA's long-term power and transmission costs would be as low as possible, consistent with sound business practices, enabling full cost recovery with power rates at or near market prices. 64 Fed. Reg. 44318, 44320 (1999). The intent of the Cost Review was to:

- give confidence to BPA customers, tribes, and constituents that future FCRPS costs would be managed effectively;
- ensure that the Subscription process resulted in a very high level of customer load commitment;
- minimize, if not avoid, transition (stranded) cost; and
- ensure that obligations to the U.S. Treasury, third-party bondholders, and fish and wildlife recovery would remain at least as secure as they are currently.

See Revenue Requirement Study, WP-02-E-BPA-02, Appendix A, for background information on the Cost Review.

The Cost Review drew on the expertise of five executives with experience in managing large organizations undergoing competitive transitions. The Cost Review recommendations did not cover fish and wildlife recovery costs. Revenue Requirement Study, WP-02-E-BPA-02, Appendix A, at 104. The Cost Review also recognized that several categories of costs were subject to change in the rates development process, including short-term power purchase expenses, net costs of the REP, General Transfer Agreement (GTA) costs, Federal interest, depreciation, and inter-business line expenses. *Id.* at 75. The Cost Review panel addressed all other FCRPS costs to be recovered through BPA power and transmission rates, with a focus on power costs in the initial Subscription period, FY 2002-2006. A draft of the panel's recommendations went through a month-long regional public comment process, which included two broadly attended public meetings. In addition, there were briefings of other groups throughout the region, including tribal, public power, and environmental interests. The draft recommendations were modified to take into account comments received, and then submitted to the Administrator, the region's Governors, the Northwest Congressional delegation, and the House and Senate Committees on Appropriations in March 1998.

The recommendations outlined in the Cost Review were developed on an exception basis, using a cost baseline that already included significant cost control initiatives. As such, rather than indicating a level of costs, the recommendations set cost savings targets as reductions from the existing cost baseline.

For BPA as a whole, the sum of the recommended cost reductions and efficiency gains was estimated to equal $136.9 million on average annually over the five-year period, FY 2002-2006. For the generation function, the reductions and gains were estimated to be $145.7 million on average annually over the same five-year period. For additional information about these recommendations and the Cost Review, *see* Revenue Requirement Study, WP-02-E-BPA-02, Appendix A.

In June 1998, BPA began a public involvement process entitled Issues ’98. Issues ’98 was designed to provide the region with an overview and context for major policy issues surrounding BPA’s future, including cost management. In addition to taking written comment, BPA held three public meetings within the region to provide an opportunity for the public to participate. BPA notified process participants that Issues ’98 was their opportunity to comment on BPA’s proposed implementation plan of the Cost Review recommendations. At the conclusion of the Issues ’98 process, BPA completed and released the “Cost Review Implementation Plan.” This document, published in October 1998, summarized the 13 recommendations of the Cost Review, the implementation plan, and relevant customer comments. Revenue Requirement Study, WP-02-E-BPA-02, Appendix A, at 71-91. The Revenue Requirement Study, WP-02-E-BPA-02, reflects the “Cost Review Implementation Plan,” with some updates and adaptations. *Id.* at 107-114. *See also* DeWolf *et al.*, WP-02-E-BPA-13, at 2-7.

The Cost Review recommendations did not address fish and wildlife recovery costs. Rather, another public review process occurred that directly addressed BPA’s fish and wildlife funding obligations. In September 1996, the Secretaries of Energy, Commerce, Army and Interior signed a Memorandum of Agreement (MOA) on behalf of five Federal agencies – BPA, NMFS, COE, USFWS, and Reclamation. This MOA stabilized BPA’s financial obligations for fish and wildlife over a six-year period, FY 1996-2001. 64 Fed. Reg. 44318, 44320 (1999). In 1997, the Northwest Congressional delegation requested the assistance of the Administration in formulating a post-2001 fish and wildlife recovery strategy. *Id.* at 44321.

On September 21, 1998, Vice President Gore announced that “a new set of principles will enable the BPA to continue providing low-cost power in the PNW while committing necessary funding for salmon restoration in the Columbia River Basin.” Volume 1, Revenue Requirement Study Documentation, WP-02-E-BPA-02A, at 58. The public process that culminated in the Principles focused on developing guidelines for structuring BPA’s approach to Subscription contracts and BPA’s FY 2002-2006 power rates to ensure that BPA could meet all its financial obligations, including those for fish and wildlife recovery. 64 Fed. Reg. 44318, 44321 (1999). The Principles specify that BPA will take into account the full range of potential fish and wildlife costs, as reflected in 13 long-term alternatives for configuration of the FCRPS, and treat each alternative as if it is equally likely to occur. *Id.* Because power rates are being set before final decisions and approvals on a fish and wildlife recovery strategy are made, the driving goal of the Principles is to “keep the options open.” This is accomplished by taking into account the broad range of potential costs associated with each hydrosystem configuration alternative.

Issue

Whether the spending levels included in revenue requirements are consistent with commitments made by BPA in the Cost Review and Issues ’98.

Parties' Positions

Public Power Council (PPC) contends that expenses in revenue requirements are higher than recommended in the Cost Review and adopted by BPA in Issues '98. Opatrny *et al*., WP-02-E-PP-02, at 2; PPC Brief, WP-02-B-PP-01, at 9. PPC argues that "BPA has violated its own rules by basing its FY 2002-2006 rates on expenses that are significantly higher than established by the Cost Review and Issues '98." *Id.* PPC argues that BPA did not adhere to its own commitment to implement the cost recommendations produced by the Cost Review and Issues '98. *Id.* PPC asserts that BPA should plan to achieve the $113 million in reductions outlined in the Cost Review process and Issues '98 that do not require legislative action for implementation. PPC Brief, WP-02-B-PP-01, at 9.

BPA's Position

BPA completed and released the "Cost Review Implementation Plan" at the conclusion of the Issues '98 process. Revenue Requirement Study, WP-02-E-BPA-02, at 16. The Cost Review Implementation Plan carefully noted cost components that were outside the Cost Review recommendations and that were subject to change in the Subscription Strategy, Fish and Wildlife planning, and rates development process. BPA's Revenue Requirement Study, WP-02-E-BPA-02, reflects the Cost Review Implementation Plan, consistent with these caveats. *Id*. at 17. Three factors led to the increase in expenses over the Issues '98 forecast: (1) implementation of the Subscription Strategy and expense changes resulting from the revenue requirement and rates development process; (2) implementation of the Principles; and (3) an adjustment to the estimate of savings needed to achieve the objectives and specific recommendations of the Cost Review. DeWolf *et al.*, WP-02-E-BPA-13, at 2. Adjusting costs to reflect the results of the Subscription Strategy, the Principles, and the revenue requirements and rates development process is fully consistent with the commitments made in the Cost Review and Issues '98. *Id*. at 3; Revenue Requirement Study, WP-02-E-BPA-02, at 108-09. The remaining adjustments were necessary to correct the estimate of savings required to meet the Cost Review recommendations and to account for the fact that additional savings through enhanced administrative efficiencies depend on legislation that has not been enacted. *Id*. at 110; DeWolf *et al.*, WP-02-E-BPA-13, at 4. With these corrections, the savings incorporated in this revenue requirement from expense reductions associated with the Cost Review recommendations are $113 million. *Id*.

Evaluation of Positions

PPC argues that BPA did not adhere to its own commitment to implement the cost recommendations produced by the Cost Review and Issues '98. Opatrny *et al*., WP-02-E-PP-02, at 2. PPC provides a categorical description of the increases in generation revenue requirements over cost levels discussed in the Cost Review and Issues '98. *Id.* However, what PPC neglects to add is that certain cost areas discussed in Issues '98 were specifically and clearly identified as subject to change in the Subscription Strategy, Fish and Wildlife planning, and rate development process. Revenue Requirement Study, WP-02-E-BPA-02, at 17. These areas were described more fully in BPA's testimony.

> The Issues ’98 forecast, however, also recognized two key areas that would have to be developed and finalized in the context of the power rate case:
>
> - Fish and wildlife funding amounts shown in Issues ’98 did not include operational costs (*i.e.*, power purchases related to fish and wildlife recovery) and did not reflect averages of the range of system configuration alternative costs for O&M and capital called for in the [Fish and Wildlife Funding] Principles (*see* Appendix A of Cost Review Implementation Plan in the Revenue Requirement Study, WP-02-E-BPA-02); and
>
> - Several cost components subject to change in the revenue requirements and rates development process, namely, short-term power purchase expense, net costs of the REP, GTA costs, Federal interest and depreciation, and inter-business line expenses.

DeWolf *et al*., WP-02-E-BPA-13, at 3-4.

Changes in the two areas described above account for $438 million of the $489 million increase in forecasted expenses. DeWolf *et al*., WP-02-E-BPA-13, at 3. Since they were identified as subject to change after the Cost Review, adjusting costs in these areas to reflect the results of the Subscription Strategy, the Principles, and the revenue requirement and rate development process is consistent with the commitments made in the Cost Review and Issues ’98. *Id.*; Revenue Requirement Study, WP-02-E-BPA-02, at 108-09. The remaining adjustments were necessary to correct the estimate of savings required to meet the Cost Review recommendations and to account for the fact that additional savings through enhanced administrative efficiencies depend on legislation that has not been enacted. *Id.* at 110; DeWolf *et al.*, WP-02-E-BPA-13, at 4. *See also* Revenue Requirement Study, WP-02-E-BPA-02, at 113-14, for crosswalk tables and descriptive narrative that explain the changes to program levels due to outside processes since the Cost Review and Issues ’98.

PPC asserts that BPA should plan to achieve the $113 million in reductions outlined in the Cost Review process and Issues ’98 that do not require legislative action for implementation. PPC Brief, WP-02-B-PP-01, at 9. In making this assertion, PPC gives the impression that BPA is not committed to these savings. In fact, the full $113 million in savings is included in expense estimates in the revenue requirement. DeWolf *et al.*, WP-02-E-BPA-13, at 4.

See also BPA’s discussion of Program Spending Levels, *supra.*

Columbia River Inter-Tribal Fish Commission (CRITFC)/Yakama state in their brief on exceptions that they “support the position taken by the PPC that BPA should not have assumed that all of the cost review savings will be implemented.” CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 23. BPA believes that CRITFC/Yakama have misstated PCC’s position, and BPA staff is unclear what CRITFC/Yakama intended. As stated above, BPA asserts that BPA should plan to achieve the $113 million in reductions outlined in the Cost Review process and Issues ’98 that do not require legislative action for implementation. PPC Brief, WP-02-B-PP-01, at 9. The PPC issue is addressed above.

Decision

The spending levels included in revenue requirements are consistent with commitments made by BPA in the Cost Review and Issues '98 for FY 2002-2006, including any cost revisions necessary to incorporate the results of the Subscription Strategy, the Principles, and the changes resulting from the revenue requirement and rate development process.

5.3.2 Fish and Wildlife and Cultural Resources Expenses

Issue 1

Whether the fish and wildlife protection costs in the revenue requirement provide the funding needed to meet applicable environmental laws.

Parties' Positions

CRITFC/Yakama state that "[t]he Northwest Power Act provides that all laws applicable to the Federal Columbia River Power System (FCRPS) are to be construed in a consistent manner and in a manner consistent with applicable environmental laws. 16 U.S.C. §839." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 11. Further, ". . . Bonneville must consider the affects [sic] of those laws on setting rates and whether those rates are based on the Administrator's total system costs. 16 U.S.C. §839e(a)(2)(B)." *Id*.

CRITFC/Yakama allege that BPA has erred by assuming a low probability for fish and wildlife alternatives that are most likely to comply with applicable Federal and environmental laws. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 11.

CRITFC/Yakama argue that BPA's revenue requirements and risk analysis do not adequately address the Clean Water Act (CWA), the Endangered Species Act (ESA), the Fish and Wildlife Coordination Act (F&WCA), and the Northwest Power Act. *Id*. at 11-19.

Upper Columbia United Tribes (UCUT) incorporates by reference the arguments made by CRITFC/Yakama regarding BPA's obligations under the Northwest Power Act, the F&WCA, the CWA, and the ESA. UCUT Brief, WP-02-B-UC-01, at 21.

The Shoshone-Bannock Tribes state that CRITFC/Yakama have "successfully devoted a great deal of effort in pointing out the inadequacies of BPA's proposal in covering the [CWA], the [ESA] and the [F&WCA]." Shoshone-Bannock Brief, WP-02-B-SH-01, at 9. Therefore, the Shoshone-Bannock Tribes support and join in the position taken by CRITFC/Yakama in their initial brief. *Id.*

BPA's Position

The Northwest Power Act requires BPA to protect, mitigate, and enhance fish and wildlife, and to provide them equitable treatment *along with the other purposes BPA fulfills under that Northwest Act*. 16 U.S.C. §839b(h)(10)(A) and §839b(h)(11)(A). (Emphasis added.) The legislative history of the Northwest Power Act underscored this intent, where Rep. Dingell stated

that the fish and wildlife provisions were not meant to "undo the power developments of the past" and that the mitigation anticipated was to be prospective, not retrospective.
126 Cong. Rec. E5105 (1980).

BPA stated in the Federal Register notice:

> . . . [F]inal decisions and approvals on a fish and wildlife recovery strategy and funding are not expected during this rate proceeding. Because rates are being set before decisions and approvals are made, the [Fish and Wildlife Funding] Principles take into account the broad range of potential costs associated with the hydrosystem configuration alternatives under consideration at the time the Principles were adopted. The Principles are intended to ensure that BPA's rate and power sales contracts yield a very high probability of meeting all post-2001 financial obligations, including BPA funding obligations for the fish and wildlife recovery strategy that is eventually adopted.

64 Fed. Reg. 44318, 44321 (1999).

At this time, there is no consensus regarding which Fish and Wildlife Alternative should be implemented, or even which Alternative is most likely to result in better salmon recovery. DeWolf *et al*., WP-02-E-BPA-39, at 28. "In the absence of clear science or regional consensus, BPA and the [Clinton] Administration consider it prudent to assume that all options identified in the Principles are equally likely to occur for purposes of setting rates . . ." *Id*.

<u>Evaluation of Positions</u>

CRITFC/Yakama allege that BPA has erred by assuming a low probability for the fish and wildlife alternatives that are most likely to comply with applicable Federal and environmental laws. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 11.

BPA disagrees with CRITFC/Yakama's assertion that BPA's revenue requirements and risk analysis do not adequately address its obligations under Federal and environmental laws because BPA assumed a low probability for fish and wildlife alternatives that CRITFC/Yakama allege are most likely to comply with applicable laws. The 13 Fish and Wildlife Alternatives established in the Principles development process represent, in the Clinton Administration's judgment and based on extensive regional input, a reasonable range within which the costs of eventual decisions on system reconfiguration and related operations can be expected to fall. DeWolf *et al.*, WP-02-E-BPA-13, at 9. The Principles are intended to "keep the options open" for future decisions by: (1) specifying that each of the 13 Fish and Wildlife Alternatives should be treated by BPA as equally likely to occur; and (2) establishing a high cost-recovery goal, expressed as an 88 percent/five-year TPP goal. *Id.* Thus, the 13 Fish and Wildlife Alternatives represent a set of assumptions, a forecasting convention, to establish capital investment and O&M levels, system operations assumptions, and risk analysis assumptions for purposes of setting rates. *Id.*

CRITFC/Yakama argue that BPA's revenue requirements and risk analysis do not adequately address the CWA, the ESA, the F&WCA, and the Northwest Power Act. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 11-19. Each will be addressed in turn.

Clean Water Act

CRITFC/Yakama state that "[t]he Environmental Protection Agency has found that 'the water quality standards for maximum water temperature and the total dissolved gas standard are commonly exceeded often by a substantial amount' . . . at the Corps of Engineers' dams on the Snake and Columbia Rivers." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 12. CRITFC/Yakama cite section 313 of the CWA which provides, in relevant part, that:

> Each department, agency, or instrumentality of the . . . Federal Government,
>
> (1) having jurisdiction over any property or facility . . . shall be subject to, and comply with, all Federal, State, interstate, and local requirements . . . respecting the control and abatement of water pollution in the same manner, and to the same extent as any nongovernmental entity.

33 U.S.C. §1323(a).

CRITFC/Yakama then allege that "[m]ost of these Clean Water Act measures on the Corps of Engineers' dams would be repaid by Bonneville." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 13.

CRITFC/Yakama argue that BPA "should have assumed that all of the [13] fish and wildlife funding alternatives would include sufficient measures to meet the CWA standards." *Id.*

A policy of COE is to operate and configure its projects consistent with state water standards when possible. *Digest of Water Resources Policies and Authorities, Engineering Pamphlet 1165-2-1*, dated February 15, 1996. Whether Federal agencies operate and configure dams inconsistent with state water standards and how they should reduce or avoid exceedances are unresolved legal and policy issues. These issues are currently in litigation with respect to the COE's lower Snake River projects. *National Wildlife Federation v. U.S. Army Corps of Engineers*, Civil No. 99-42-FR (D. Or.). In their brief on exceptions, CRITFC/Yakama express surprise that BPA cited *National Wildlife Federation* without mentioning the recent opinion by Judge Frye. *See National Wildlife Federation v. U.S. Army Corps of Engineers*, 2000 WL 351187 (2000 D.Or.). CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 7. However, reference to this opinion was not necessary. CRITFC/Yakama state that "[t]his ruling clearly states the Corps of Engineer's projects are required to meet the Clean Water Act." *Id*. CRITFC/Yakama quote from the ruling:

> The United States Court of Appeals for the Ninth Circuit has stated that "[u]nder the Clean Water Act, <u>all federal agencies must comply with state water quality standards.</u>" [citation omitted] The plaintiffs are entitled to challenge alleged

> violations of the state water quality standards pursuant to the Administrative Procedures Act . . . [citation omitted].

National Wildlife Federation v. U.S. Army Corps of Engineers, 2000 WL 351187, at 13 (emphasis added).

But this ruling does nothing to resolve the question posed by BPA--whether Federal agencies operate and configure dams inconsistent with state water standards and how they should reduce or avoid exceedances. This ruling was in response to plaintiffs' motion for summary judgment, where they alleged that the COE 1995 ROD and the COE 1998 ROD violate the CWA because these final agency actions fail to assure that the dams will operate in compliance with state water quality standards. *Id.* These are still unresolved legal and policy issues. In fact, the opinion goes on to say that:

In determining whether the COE's decisions in the 1995 ROD and the 1998 ROD regarding the operation of the dams were arbitrary and capricious, the court must "consider whether the decision was based on a consideration of the relevant factors and whether there has been a clear error of judgment." [citation omitted] The court must consider all of the relevant factors and all of the relevant laws in deciding whether the administrative record shows that the COE has met its obligations under the CWA in the 1995 ROD and the 1998 ROD.

> The court concludes that summary judgment on the merits cannot be decided without reference to and reliance upon the administrative record supporting the 1995 ROD and the 1998 ROD.

Id.

In short, these issues are still in litigation.

CRITFC/Yakama also argue that BPA erred when "they failed to cite *Pronsolino v. Marcus* regarding the authority of the Environmental Protection Agency to list substandard rivers and to issue total maximum daily loads (TMDLs) for them. *See Pronsolino v. Marcus*, 2000 WL 356305 (N.D. Cal.)." CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 7. CRITFC/Yakama claim that "[t]hese decisions clearly point out virtually certain additional risk of higher costs that Bonneville has failed to plan for." *Id*. BPA fails to see how a case that allegedly found that the Environmental Protection Agency (EPA) has the power to list waters or issue TMDLs translates into "virtually certain additional risk" for BPA, and CRITFC/Yakama can cite to no evidence on the record that justifies its bold assertion.

The uncertainty of resolution underscores why the Principles were established. It was well-understood at the time the Principles were adopted that cost estimates would continue to evolve as the analysis, planning, and decision process for system reconfiguration and related actions progressed. DeWolf *et al.*, WP-02-E-BPA-13, at 10. But the range of costs established by these 13 Fish and Wildlife Alternatives is deemed by the Executive Branch to be sufficiently high and broad for BPA ratesetting and Subscription purposes. *Id.* Further, even if BPA were assumed to have some financial obligations related to CWA compliance, it is not clear whether BPA would bear the majority of the costs for CWA compliance as CRITFC/Yakama allege.

In their brief on exceptions, CRITFC/Yakama claim that BPA erred:

> when it suggested that it is not clear whether BPA would bear the majority of the costs for CWA compliance. If the Corps is required to modify its dams to meet the CWA, BPA will reimburse those measures pursuant to the allocation formula established by Congress. Any other assumption would require changes in Federal law. Assuming that the law will change so as to reduce BPA's obligations is unwarranted.

CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 8.

CRITFC/Yakama find errors where none exist and then leap to a conclusion that bears no relation to the original statement made by BPA. Contrary to CRITFC/Yakama's implication, BPA's statement does not deny any obligation it has under law to reimburse appropriate power-related costs, nor does BPA assume that the law will change. BPA merely states a fact--there is no clear indication to what extent BPA would incur costs for CWA compliance. CRITFC/Yakama can cite to no evidence on the record indicating that BPA's statement is in error.

<u>Endangered Species Act</u>

CRITFC/Yakama state that "[t]he Endangered Species Act, 16 U.S.C. §1531-1543, protects species listed as either endangered or threatened and imposes substantive duties on Bonneville." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 13. CRITFC/Yakama argue that:

> [T]he higher cost alternatives are more likely to be implemented because they are more likely to result in survival and recovery of salmon stocks listed under the ESA, whereas the lower cost alternatives are unlikely to result in survival and recovery. By assigning an equal weight to these options, BPA underestimates its potential fish and wildlife cost exposure, since fish and wildlife options that are unlikely to meet survival and recovery receive the same weight as those that would meet survival and recovery. Therefore, BPA's approach increases the risks to BPA and Treasury.

Sheets *et al.*, WP-02-E-CR/YA-05, at 19.

BPA agrees that it must avoid jeopardy of listed species and aid in their conservation and recovery pursuant to the ESA. 16 U.S.C. §1536. However, while BPA supports the Federal goal of restoration, BPA itself does not have a legal duty to "restore" fish and wildlife to historical levels, and courts have indicated that such an obligation on dam owners and operators in the PNW would be unproductive. *American Rivers v. FERC*, 187 F.3d 1007 (9th Cir. 1999), as amended, 201 F.3d 1186, 1197 (9th Cir. 2000) ("It defies common sense and notions of pragmatism to require [FERC or license applicants] to 'gather information to recreate a 50-year-old environmental base upon which to make present day development decisions.'")

CRITFC/Yakama argue in their brief on exceptions that BPA erred when it contended that BPA does not have a legal duty to restore fish and wildlife to historical levels. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 8. CRITFC/Yakama state that "[t]here is no discussion [in *American Rivers*] about what dam owners are responsible for in terms of fish restoration. Moreover, the citation has nothing to do with the Endangered Species Act . . . Bonneville's misdirected analysis is typical of the DROD and indicates the lack of attention to CR/YA issues." *Id*. BPA cited the legislative history of the Northwest Power Act, *supra* in ROD section 5.3.2, for the proposition that the fish and wildlife provisions were not meant to "undo the power developments of the past" and that the mitigation anticipated was to be prospective, not retrospective. 126 Cong. Rec. E5105 (1980). BPA cited *American Rivers v. FERC*, 187 F.3d 1007 (9th Cir. 1999), as amended, 201 F.3d 1186, 1197 (9th Cir. 2000), simply for the proposition that FERC does not expect non-Federal hydro projects to be judged by a pre-project baseline either.

CRITFC/Yakama allege that "independently peer reviewed biological analyses from PATH (the Plan for Analyzing and Testing Hypotheses) indicate [the lower cost alternatives] would be unlikely to meet Endangered Species Act recovery . . . " Sheets *et al.*, WP-02-E-CR/YA-05, at 20; CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 14. CRITFC/Yakama also introduce new evidence that was never admitted into the record:

> Recently, in its anadromous fish appendix (*see* Appendix A: Anadromous Fish, Lower Snake River Juvenile Salmon Migration Feasibility Report/Environmental Impact Statement . . .), the NMFS concluded that breaching of the four snake river [sic] dams provided the highest probability of recovery for listed stocks. *See* the Executive Summary of PATH FY 98 Final Report, page 9.

CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 15.

In this section 7(i) process, neither BPA nor other parties have had the opportunity to review the new information introduced by CRITFC/Yakama, *supra*, or to test their conclusions through discovery or cross-examination. In their brief on exceptions, CRITFC/Yakama state:

> BPA argues [that] it has not had the opportunity to review the Federal studies cited by CRITFC in its Initial Brief. That is surprising as these studies have been extensively reviewed by the Federal Caucus where BPA is an active member. These materials are contained or linked to the Federal Caucus web page that is maintained on the BPA web page. BPA should have reviewed these federally sponsored studies that are critical to making any informed judgement about the actions needed to restore fish and wildlife and which will affect the output from the Federal dams.

CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 9.

Notwithstanding CRITFC/Yakama's allegation, the fact of the matter is that there is still no clear science or regional consensus on a fish and wildlife recovery plan. While it is impossible to predict precisely BPA's fish and wildlife costs during the upcoming rate period, the range of costs represented by the 13 Fish and Wildlife Alternatives represents a reasonable range of costs given the variety of possible future alternatives for program implementation and operational impacts. DeWolf *et al*., WP-02-E-BPA-39, at 32. Although CRITFC/Yakama may not be "convinced" by BPA's proposal, there is ample evidence in the record to support BPA's proposal. *See, generally,* BPA's extensive discussion of fish and wildlife issues in ROD chapters 5, 6, 7, and 18.

Notwithstanding this new information, the 13 Fish and Wildlife Alternatives established in the Principles development process represent, in the Clinton Administration's judgment and based on extensive regional input, a reasonable range within which the costs of eventual decisions on system reconfiguration and related operations can be expected to fall. DeWolf *et al.*, WP-02-E-BPA-13, at 9. The Principles are intended to "keep the options open" for future decisions by: (1) specifying that each of the 13 Fish and Wildlife Alternatives should be treated by BPA as equally likely to occur; and (2) establishing a high cost-recovery goal, expressed as an 88 percent/five-year TPP goal. *Id.* Thus, the 13 Fish and Wildlife Alternatives represent a set of assumptions, a forecasting convention, to establish capital investment and O&M levels, system operations assumptions, and risk analysis assumptions for purposes of setting rates. *Id.*

CRITFC/Yakama also allege that "Bonneville's inadequate analysis of the risk it faces due to its failure to consider ESA compliance in the equal weighting of fish and wildlife alternatives is evident in their testimony." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 14. CRITFC/Yakama point to a response from BPA to a data request wherein BPA was asked to provide any documentation on the biological rationale for the probabilistic weighting of the 13 Fish and Wildlife Alternatives that BPA used to determine what level of funding to use in the rate case. CRITFC/Yakama stated that "Bonneville admitted, 'the probabilistic weighting of the 13 Fish and Wildlife Alternatives was not based on any biological rationale.'" *Id*. What CRITFC/Yakama neglected to include, however, was the remainder of BPA's response to the data request: "The keep-the-options-open strategy that underpins the Fish and Wildlife Funding Principles is the basis for weighting each of the 13 alternatives as equally likely to occur. (*see* DeWolf *et al.*, WP-02-E-BPA-13, at 16-19)." Lothrop, WP-02-E-CR/YA-02, Attachment 1 (citing BPA data response to Request No. CR-BPA:027).

It is inconsistent for CRITFC/Yakama to argue that BPA's risk analysis was inadequate because it did not undertake an independent analysis of the probabilistic weighting of the 13 Fish and Wildlife Alternatives developed in the Principles process. Those Alternatives were rigorously discussed in the very extensive public process. BPA adhered to limitations expressed in the Federal Register Notice regarding the scope of the power rate proceeding:

> Included among the policy decisions, commitments, and assumptions that are not at issue in this rate proceeding are: . . . (1) the incorporation of the full range of costs using the same probabilistic method BPA uses for other cost and revenue uncertainties in its ratemaking; (2) the assumption that all 13 alternatives are equally likely to occur; . . ."

64 Fed. Reg. 44318, 44322-23 (1999).

CRITFC/Yakama object to "Bonneville's continued mischaracterization of events and Bonneville's attempts to declare issues are outside the scope set forth in the Federal Register Notice (FRN)." CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 10. They also object to BPA's characterization of the "rigorous discussion" of the Fish and Wildlife Alternatives in the Principles process. *Id*. CRITFC/Yakama allege that various incidents occurred in the development of the Principles that do "not comport with 'rigorous discussion.'" *Id*. It is clear that CRITFC/Yakama disagree with how the Principles were developed. Nevertheless, this rates proceeding is not the appropriate forum to address any perceived grievances CRITFC/Yakama may have had with the Principles process. Even if CRITFC/Yakama's allegations were appropriate issues to be raised in this rates proceeding, there is no evidence on the rate case record to support CRITFC/Yakama's complaints.

Fish and Wildlife Coordination Act

CRITFC/Yakama state that the USFWS recently completed a Coordination Act Report in December 1999, [as required under the F&WCA] on the effects of breaching the Snake River Dams on fish and wildlife. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 16. They indicate that a copy of the draft of this report was completed in the summer of 1999 in time for BPA's consideration in this rate case. *Id.* CRITFC/Yakama argue that "Bonneville's rate proposal should take into account the conclusions of this report and give significantly higher weight to Alternatives 8u and 13u and less weight to the non-natural river alternatives." *Id.* Further, CRITFC/Yakama allege that the weightings BPA gave to Alternatives 8u and 13u are inconsistent with the findings of the Coordination Act Report, which is inconsistent with the F&WCA. *Id.* at 16-17.

The USFWS prepared the draft FWCA report that CRITFC/Yakama references. By law, the COE was required to give it "full consideration." 16 U.S.C. §662. BPA is under no legal obligation to consider the recommendations of a draft report in its ratesetting process. These draft conclusions and the COE's responses to them may very well change before becoming final. In its brief on exceptions, CRITFC/Yakama argue that BPA erred "in its decision that it does not have to take the findings of the Coordination Act Report prepared by the U.S. Fish and Wildlife Service into consideration in setting its rates." CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 11. CRITFC/Yakama then go on to say that:

> We do not need to argue whether BPA has a "legal" obligation to consider the findings. It is prudent business practice to be fully aware of additional environmental costs during the next rate period so BPA can set its rates to meet those costs and assure Treasury repayment. It is arbitrary and capricious to ignore pertinent information . . .

Id.

CRITFC/Yakama state that they do not need to argue whether BPA has a legal obligation to consider the findings of the Report mentioned above. BPA can only conclude that CRITFC/Yakama can cite to no such legal obligation to support its allegation. Further, CRITFC/Yakama's statement that it is arbitrary and capricious for BPA to "ignore pertinent information" lacks substance or support in the record. In addition, CRITFC/Yakama do not substantiate any "additional environmental costs" that BPA is obligated to pay based on the Report.

Here again, CRITFC/Yakama have provided yet another good example of why the Principles were developed. There is no resolution yet as to the best way to ensure fish and wildlife recovery. The Principles are intended to "keep the options open" for future decisions by: (1) specifying that each of the 13 Fish and Wildlife Alternatives should be treated by BPA as equally likely to occur; and (2) establishing a high cost-recovery goal, expressed as an 88 percent/five-year TPP goal. DeWolf *et al*., WP-02-E-BPA-13, at 9.

<u>Northwest Power Act</u>

CRITFC/Yakama state that "Bonneville has specific obligations to implement the Columbia River Basin Fish and Wildlife Program developed by the Northwest Power Planning Council . . . " CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 17-18. They indicate that "[t]he current Columbia River Basin Fish and Wildlife Program was adopted by the Council in 1994, with resident fish and wildlife amendments in 1995. That Program calls for drawdowns at the four Lower Snake River dams, and John Day Dam on a schedule that called for implementing these measures before 2000. It also calls for additional flows, significant habitat restoration, and hatchery reforms." *Id.* at 18.

CRITFC/Yakama argue that "Bonneville's rate proposal does not include sufficient funds to implement the Program. This is inconsistent with the Program." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 18.

CRITFC/Yakama argue that "Bonneville unlawfully disregards the Columbia River Basin Fish and Wildlife Program that was adopted in 1994. Bonneville cannot carry out its duties under the Act by developing a different plan or by waiting for a new Program from the Council, which Bonneville apparently hopes maybe [sic] better suited to its pledge to hold rates at their current level." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 39-40.

In their brief on exceptions, CRITFC/Yakama argue that "[i]n the context of the Northwest Power Act, Bonneville has an express duty to use its fund and authorities to protect, mitigate, and enhance fish and wildlife in the Columbia Basin to the extent affected by the development and operation of hydropower in the Basin. 16 U.S.C. §839b(h)(10)(A). CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 31.

BPA agrees that it must act consistently with the NWPPC's Program as well as the other purposes of the Northwest Power Act. 16 U.S.C. §839b(h)(10)(A). However, BPA disagrees that it must implement the Program measures without considering other ways in which the Program's goals can be achieved. If BPA meets the goals of the Program, it need not necessarily fund the specific measures proposed. *See, generally, Northwest Resource Information Ctr. v.*

Northwest Power Planning Council, 35 F.3d 1371, 1378 (9th Cir. 1994), *cert. den.* 516 U.S. 806, 116 S.Ct. 50 (1995) (NWPPC can guide but not command Federal river management). *See also ALCOA v. Administrator*, *Bonneville Power Administration*, 175 F.3d 1156 (9th Cir. 1999), *cert. den.,* 120 S.Ct. 983 145 L. Ed. 2d 933 (2000).

In their brief on exceptions, CRITFC/Yakama state:

> Again, we do not plan to argue the legal issues in a forum where BPA is the decision maker, but we find no place in the record where BPA states how it plans to meet the Council's goal of restoring 5 million returning salmon and steelhead to the mouth of the Columbia River. BPA has no such alternative and its argument is simply a smoke screen.

CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 11.

CRITFC/Yakama once again do not lay out their legal issues. In fact, CRITFC/Yakama's contempt for the section 7(i) process is evident in its refusal to argue legal issues in a forum where the BPA Administrator is the decisionmaker. BPA is, therefore, unable to respond in any substantive way. CRITFC/Yakama also characterizes as "simply a smoke screen" the fact that BPA described its flexibility in meeting the goals of the Council program. Although CRITFC/Yakama imply that BPA has some obligation to state specifically how it plans to meet a particular Council goal in this section 7(i) rate proceeding, CRITFC/Yakama are mistaken. Further, CRITFC/Yakama can cite to no such obligation.

CRITFC/Yakama argue in their brief on exceptions that "Bonneville is also required to provide equitable treatment to fish and wildlife in its decision making. 16 U.S.C. §839b(h)(11)(A). Keeping rates 35 percent below the market price of electricity while not providing sufficient funding to avoid the extinction of salmon and steelhead is not equitable treatment nor does it comply with the other provisions of section 4(h) of the Act." CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 11-12. In 1997, the Ninth Circuit Court of Appeals addressed the issue of equitable treatment with respect to the Non-Treaty Storage Agreements in *Northwest Environmental Defense Center*. The court found that:

> BPA's view that it must balance power needs and wildlife needs on a systemwide basis is a reasonable reading of the Northwest Power Act. Section 839b(h)(11)(A) does not explicitly require that each action individually provide equitable treatment. Moreover, in its directive to the Council, Congress recognized the need for a comprehensive approach to fish and wildlife protection on the Columbia . . . While each power marketing action that affects the system implicates the equitable treatment provision, BPA may properly exercise its obligation by insuring equitable treatment for fish on a systemwide basis.

Northwest Environmental Defense Center v. BPA, 117 F.3d 1520, 1533-34 (9th Cir. 1997).

CRITFC/Yakama emphasize only certain provisions in the Northwest Power Act. The provisions that CRITFC/Yakama would focus on do not take precedence over other provisions in the Northwest Power Act. In addition to funding fish and wildlife recovery, BPA is also obligated under the Northwest Power Act to assure the PNW an "adequate, efficient, economic, and reliable power supply." 16 U.S.C. §839(2). BPA must balance its fish and wildlife funding obligations with its other obligations under the Northwest Power Act.

CRITFC/Yakama also state that BPA's probabilistically weighted approach gave equal weight to 12 alternatives that were inconsistent with the NWPPC's Program and one alternative that was somewhat similar to the Council's Program. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 18. CRITFC/Yakama allege that "[t]his approach does not take the Program into account at each relevant stage of decision making to the maximum extent practicable as required by the [Northwest Power] Act [16 U.S.C. §839b(h)(11)(A)]." *Id.*

The 13 Fish and Wildlife Alternatives established in the Principles development process represent, in the Clinton Administration's judgment and based on extensive regional input, a reasonable range within which the costs of eventual decisions on system reconfiguration and related operations can be expected to fall. DeWolf *et al.*, WP-02-E-BPA-13, at 9. The Principles are intended to "keep the options open" for future decisions by: (1) specifying that each of the 13 Fish and Wildlife Alternatives should be treated by BPA as equally likely to occur; and (2) establishing a high cost-recovery goal, expressed as an 88 percent/five-year TPP goal. *Id.* Thus, the 13 Fish and Wildlife Alternatives represent a set of assumptions, a forecasting convention, to establish capital investment and O&M levels, system operations assumptions, and risk analysis assumptions for purposes of setting rates. *Id.*

Decision

The fish and wildlife protection costs in revenue requirements provide the funding needed to meet applicable environmental laws. At this time, there is no consensus regarding which Fish and Wildlife Alternative should be implemented, or even which Alternative is most likely to result in better salmon recovery. This section 7(i) rates proceeding is not the appropriate forum to decide this issue, and BPA has included the range of costs for the 13 Fish and Wildlife Alternatives without prejudice or preference of one alternative over another.

Issue 2

Whether the generation revenue requirements adequately reflect the cost and risk associated with cultural resource protection.

Parties' Positions

UCUT argues that the $3.5 million amount included in the generation revenue requirements has been budgeted in years past for cultural resource protection, and this amount has historically and consistently been inadequate to complete program requirements and comply with Federal law. Osterman, WP-02-E-UC-01, at 2; UCUT Brief, WP-02-B-UC-01, at 9. Moreover, UCUT argues that it is likely that a number of unplanned cultural resource issues may arise during the five-year rate period. *Id.* Therefore, UCUT argues that BPA's cultural resource budget needs to be increased significantly even to properly come into compliance with law at existing sites and to meet the planned cultural resource needs. Osterman, WP-02-E-UC-01, at 3. Furthermore, UCUT argues that BPA's risk management should be flexible enough to cover unplanned cultural resources issues such as the discovery of the Kennewick Man, or a proper Inadvertent Discovery Fund should be in place. *Id.* In addition, UCUT introduces new evidence in its initial brief that suggests that $10.5 million per year is a reasonable sum for bringing the existing cultural resources protection program into compliance with law. UCUT Brief, WP-02-B-UC-01, at 10. UCUT also argues that an inadvertent discovery fund totaling $5 million for the rate period should be created. *Id.*

UCUT argues in its brief on exceptions that it is unreasonable for BPA to design rates which increase risk by reflecting cultural resource budgetary numbers which do not comply with Federal law and are shown to be insufficient. UCUT Ex. Brief, WP-02-R-UC-01, at 2-3.

CRITFC/Yakama and the Shoshone-Bannock Tribes support the UCUT position. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 36, 55; Shoshone-Bannock Brief, WP-02-B-SH-01, at 9. In their brief on exceptions, CRITFC/Yakama argue that implementing the measures that will begin to meet the CWA, the ESA, and treaty and trust obligations to Columbia Basin tribes will reduce the probability of paying BPA's debt to the Treasury on time and in full. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 7. CRITFC/Yakama support and incorporate by reference the exceptions filed by UCUT on this issue. *Id*. at 12.

<u>BPA's Position</u>

BPA argues that a budget level for the cultural resource protection program has not yet been determined.

> Q. While the fish and wildlife budget is assumed to be expansive enough to cover $200,000 per year in administrative expenses for cultural resources protection and that other fish and wildlife projects may have a cost component for cultural resources, no other funds are specifically budgeted for cultural resources at this time in the Revenue Requirement Study, WP-02-E-BPA-02 is that correct?
>
> A. (Mr. DeWolf) I think it is important to point out that there are no fully established budgets for fish and wildlife costs in 2002 through 2006, including any component parts having to do with cultural resources. They are [our] estimates for rate setting purposes at this point only. So there may or may not be amounts contained in--that were used in developing or building the forecasts of costs associated with the different alternatives, but it is all subject to review and change as we go forward.

Tr. 506.

BPA also argues that the determination of program levels is beyond the scope of this rate proceeding.

> Q. This treatment of the cultural resources budget is not a new policy implemented for this rate case to your knowledge. Is this level of budgeting for cultural resources consistent with past BPA policy?

> A. (Mr. DeWolf) We do not know the answer and would argue that it is beyond the scope of what we are here to sponsor as testimony.

Tr. 506.

Further, the analysis UCUT used to determine what it considered to be a "reasonable sum" for bringing the existing cultural resources protection program into compliance with law was not presented in its prior testimony. Neither BPA nor any other party had the opportunity to test the analysis underlying these numbers through discovery or cross-examination.

There may be some risk associated with unplanned cultural resource issues that arise during the FY 2002-2006 rate period. BPA adds PNRR to the generation revenue requirements to mitigate against such potential financial risks. Revenue Requirement Study, WP-02-E-BPA-02, at 39.

Evaluation of Positions

UCUT argues that the current cultural resource budget is inadequate for the known and usual cultural resources obligations. UCUT Brief, WP-02-B-UC-01, at 9. In addition, UCUT argues that the recent example of the discovery of the Kennewick Man in July 1996 demonstrates the likelihood that a number of unplanned issues will arise. Osterman, WP-02-E-UC-01, at 2; UCUT Brief, WP-02-B-UC-01, at 9. UCUT asserts that BPA's entire cultural resources budget was used to comport with cultural issues surrounding the Kennewick Man. UCUT Brief, WP-02-B-UC-01, at 9. Therefore, BPA should include additional funding for cultural resource protection. *Id.* at 10.

UCUT and CRITFC/Yakama argue that BPA should increase its program levels for cultural resources funding to $10.5 million annually (with an additional $5 million amount designated for an inadvertent discovery fund). However, the spending levels for the operations and maintenance direct funding agreements with the COE and Reclamation have already been addressed in the Cost Review.

> [T]he Cost Review recommendations and BPA's planned implementation of those recommendations have already received extensive public review. Pursuant to §1010.3(f) of *BPA's Procedures*, the Administrator directs the Hearing Officer to exclude from the record any material attempted to be submitted or arguments attempted to be made in the hearing which seek to in any way visit the appropriateness or reasonableness of BPA's decisions on spending levels, as included in BPA's test period revenue requirement for FYs 2002 through 2006.

64 Fed. Reg. 44318, 44322 (1999).

In their brief on exceptions, CRITFC/Yakama state that they believe "there is sufficient information in the record to make a reasonable estimate of Bonneville's future costs and include them in the base revenue requirements." CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 12.

UCUT's and CRITFC/Yakama's argument for supplemental program level funding is beyond the scope of this power rate proceeding.

BPA is responsible to pay the power-related costs associated with the Federal dams operated by the COE and Reclamation. If those costs are properly found to be higher, BPA will meet its financial obligations. BPA faces many risks during the FY 2002-2006 rate period. The risk of an inadvertent discovery, such as the Kennewick Man, is undoubtedly one of these risks. However, no quantification of such a risk was demonstrated by the parties. The CRITFC/Yakama assertion that implementing measures to meet certain laws will reduce BPA's TPP is not supported by evidence on the record. CRITFC/Yakama Brief, WP-02-R-CR/YA-01, at 7.

Finally, this rate proceeding is not the process that determines BPA's program levels for the fiscal years of the rate period. BPA has not yet established budgets for fish and wildlife costs for the period FY 2002 through 2006. The amounts shown for cultural resources are simply estimates at this point developed for the purpose of setting rates. These estimates are subject to review and change in the future.

Decision

Since the level of the budget for the cultural resource protection program is outside the scope of this power rate proceeding, requests for additional funds to supplement BPA's program spending levels for FY 2002-2006 will not be considered. The risk associated with those expenditures is, however, at issue in this power rate proceeding. BPA acknowledges that there may be some risk in this area. BPA has considered this risk and believes it is reasonable to conclude that BPA's PNRR are adequate to cover BPA's exposure in this area.

5.4 Implementation of Fish and Wildlife Funding Principles

5.4.1 Equal Weighting of the 13 Alternatives

Issue

Whether BPA should treat each of the 13 Alternatives in the Principles as equally likely to occur.

Parties' Positions

CRITFC/Yakama argue that equal weighting of the 13 Fish and Wildlife Alternatives in BPA's proposal is inappropriate and underestimates BPA's potential fish and wildlife cost exposure, and therefore increases risk to both BPA and Treasury. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 10-11. CRITFC/Yakama claim that BPA's risk mitigation package should be adjusted to account for the higher likelihood that these more expensive alternatives are more likely to be implemented than the low cost alternatives. *Id.* at 20. In their brief on exceptions, CRITFC/Yakama state that BPA ignored their extensive analysis on this issue. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 13.

Alcoa/Vanalco argue that BPA's equal weighting is irrational. As an example, they state that over half of the alternatives include breaching dams on the Snake River, yet there is no basis for concluding that this has been authorized, and no testimony in the record to allow any conclusion that there is a greater than 50 percent probability that it will be authorized. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 90; Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 15. They argue that BPA's position in its Draft ROD is not persuasive or sufficient to carry BPA's burden of demonstrating cost recovery. *Id*. They also argue that BPA is refusing to do exactly what Congress intended it to do: predict its future costs and then set rates to meet these costs. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 17.

The IOUs argued that "BPA should have analyzed the fish and wildlife alternatives in this rate proceeding to make the best possible determination of fish costs, rather than making an arbitrary assumption that all 13 alternatives are equally likely." Eakin *et al*., WP-02-E-AC/GE/IP/MP/PL/PS-01, at 11-12. The IOUs refer to the equal weighting as arbitrary and unrealistic. They also claim that "by assuring that dam breaching was as likely as not, BPA assumed a huge cost impact." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 91.

Northwest Requirements Utilities (NRU) argued that BPA has assigned too high a probability for the more expensive fish and wildlife alternatives. "On the expense side, there is a low probability that some of the more expensive options under the 13 alternatives for system reconfiguration will ever occur." Saven, WP-02-E-NI-01, at 6.

PPC argues that "[t]he likelihood that dam breaching will be approved and implemented . . . has been significantly reduced in recent months." PPC Brief, WP-02-B-PP-01, at 47-48. They also state that "certain other parties propose to revise BPA's risk assessment and mitigation techniques in order to accommodate isolated and high cost fish and wildlife alternatives, chosen from those that the Principles direct should be equally weighted. . . . BPA should reject such proposals for to do otherwise would violate its rate pledge and misrepresent the risk faced by the agency." *Id.* at 50.

However, CRITFC/Yakama argue that BPA's use of PPC statements on page 5-17 of the Draft ROD is indicative of BPA's unwillingness to analyze the serious risk it faces. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 13. CRITFC/Yakama claims that BPA's use of PPC's argument amounts to willful blindness and is arbitrary and capricious. *Id*.

BPA's Position

BPA is implementing the Principles in the 2002 power rates (DeWolf *et al*., WP-02-E-BPA-13, at 7), treating each of the 13 Alternatives as equally likely to occur. *Id.* at 10. This treatment is integral to the "keep the options open" strategy. *Id.* The Principles are the product of extensive regional discussion and Administration direction. *See* section 2.3 *supra*; *see also* 64 Fed. Reg. 44318, 44320-21 (1999). The guidance the Principles provide is not an issue to be addressed in this rate case. *See* Burns and Elizalde, WP-02-E-BPA-08, at 4-5. *See also* 64 Fed. Reg. 44318, 44322-23.

Additionally, equal weighting recognizes that it is unknown what will be included in a final decision on a fish and wildlife plan for the region. DeWolf *et al.*, WP-02-E-BPA-39, at 28.

The impact on the revenue requirements of including breach scenarios is very small. DeWolf *et al*., WP-02-E-BPA-13, at 20-21.

Evaluation of Positions

In arguing against equal weighting, CRITFC/Yakama stated that “the higher cost alternatives are more likely to be implemented because they are more likely to result in survival and recovery of salmon stocks listed under the ESA, whereas the lower cost alternatives are unlikely to result in survival and recovery.” *See* Sheets *et al*., WP-02-E-CR/YA-05, at 19. However, as noted above, other parties believe the higher-cost alternatives are less likely to be adopted. PPC states that “the likelihood that dam breaching will be approved by Federal agencies in 2000 and implemented prior to 2006 has been significantly reduced in the last few months.” PPC Brief, WP-02-B-PP-01, at 47-48. As Alcoa/Vanalco point out, no breaching has yet been authorized. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 90.

CRITFC/Yakama state that BPA may not argue that since some utilities (which benefit from the dams but have no responsibility to restore fish and wildlife) do not support some measures, that the restoration actions are unlikely to be implemented. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 13. However, the parties which BPA cited, PPC and Alcoa/Vanalco, did not state that they do not support breaching. Rather, they argue that there are significant questions as to whether the region and Congress will make decisions and take actions in sufficient time to affect the 2002-2006 rate period costs if a breaching decision is made. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 90; PPC Brief, WP-02-B-PP-01, at 47-48. The PPC testimony is evidence that the CRITFC/Yakama position (that the more expensive alternatives are more likely to be adopted) is far from certain. While CRITFC/Yakama have argued that not considering the higher cost alternatives under-estimates the costs and risks, *Id*. at 14; and claim that BPA has ignored their arguments, *Id*. at 13; BPA has, in fact, taken a reasonable and reasoned approach in its analysis of potential fish and wildlife costs by considering the vastly differing opinions, including CRITFC/Yakama’s, as to what decisions will be made in the future. *See* ROD sections 5.4.7.2, Issue 6, and 7.7, *infra*. CRITFC/Yakama appear to be overlooking the possibility that an approach they or others suggest as the best may not be the approach adopted by the relevant decisionmakers. In any case, BPA is not the decisionmaker. Rather, BPA must estimate the likely decisions of other entities.

At this point, there is no consensus regarding which alternative should be implemented, or even which alternative is most likely to result in better salmon recovery. DeWolf *et al*., WP-02-E-BPA-39, at 28. Additionally, there is considerable regional debate and no consensus on the economic impacts and benefits of the various alternatives, with strong opinions at both ends of the spectrum. *Id.* In the absence of clear science or regional consensus, BPA and the Administration consider it prudent to assume that all options identified in the Principles are equally likely to occur for purposes of setting rates and initiating Subscription. *Id.*

Alcoa/Vanalco argue in their brief on exceptions that "BPA first excluded all evidence from the rate case regarding the 13 Fish and Wildlife Alternatives, then stated that 'there is no consensus regarding which alternative should be implemented . . . BPA cannot have it both ways." Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 17. As explained *supra*, BPA is referring to regional consensus, not rate case consensus. The rate case is not the forum where decisions will be made regarding which alternative will be implemented.

The fact that some parties have argued that dam breaching is more likely to occur than suggested by the equal weighting, while other parties argue it is less likely, supports BPA's contention that equal weighting of all 13 Alternatives is a reasonable and balanced approach.

The region is in the process of trying to develop a fish and wildlife recovery plan, and until a plan is developed, the Principles establish a reasonable approach that keeps the options open. DeWolf *et al*., WP-02-E-BPA-39, at 29. The assumption that all 13 Alternatives are equally likely is not an 'arbitrary assumption.' Indeed, the Principles are the product of extensive regional discussion and Administration direction, and the assumption is integral to the 'keep the options open' strategy. *Id.*

Alcoa/Vanalco argue that BPA is refusing to do exactly what Congress intended it to do: predict its future costs and then set rates to meet these costs. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 17. However, BPA's approach is a reasonable one, which assumes a wide range of potential costs and uncertainties, and demonstrates a very high probability that proposed rates would recover this range of costs and other uncertainties. *See* ROD section 7.2, *infra*.

The IOUs assert a "huge cost impact" results by assuming each dam breaching scenario is equally likely to occur as other scenarios. In fact, there is very minimal impact to the revenue requirement in the FY 2002-2006 rate period by assuming each dam breaching scenario is equally likely to occur as other scenarios. If dam breaching is chosen as the strategy for system reconfiguration, Congress presumably would address BPA's repayment obligations and allocations to project purposes in some manner. Changes in assumptions for the allocations to project purposes and repayment obligations yield very little or no reduction in revenue requirements for the 2002-2006 rate period. DeWolf *et al*., WP-02-E-BPA-13, at 20-21.

<u>Decision</u>

In the absence of clear science or regional consensus on a fish and wildlife recovery plan, it is reasonable for BPA to treat each of the 13 Alternatives in the Principles as equally likely to occur.

5.4.2 <u>Range of Fish and Wildlife Costs</u>

<u>Issue</u>

Whether BPA should have changed the range of costs associated with the Principles to reflect an updated market forecast.

Parties' Positions

PPC argued that the range of costs used in the Principles ($438 million to $721 million) is adequate. Hansen *et al*., WP-02-E-PP-09, at 14. Therefore, PPC asserts, BPA should reduce the level of fish and wildlife costs included in revenue requirements for the 2002-2006 rate period to the $438 million to $721 million range per year that the Principles instructed, rather than adjusting the operational costs for an increased market forecast. PPC Brief, WP-02-B-PP-01, at 50.

CRITFC/Yakama, on the other hand, argued that BPA should update the range of fish and wildlife costs. They argued that BPA staff had stated that electricity prices would be updated when AURORA model work was completed, Sheets *et al*., WP-02-E-CR/YA-05, at 4; and that BPA has not adjusted the range inappropriately. *Id.* at 17.

BPA's Position

The Principles did not commit BPA to an exact set of costs. To the contrary, the second Principle states, in part, that "BPA will use the full range of potential fish and wildlife costs and financial impacts during the 2002-2006 rate period (currently estimated at $438 million to $721 million) for planning purposes . . . " DeWolf *et al*., WP-02-E-BPA-39, at 26-27. This means that at the time the Principles were adopted, the costs of the Alternatives were estimated to be in a range of $438 million to $721 million annually. *Id.* at 27. BPA was aware that the component of the financial impacts due to operational constraints could change as the market forecast was updated, and as BPA's ability to model the operational impacts improved. *Id.*

In its proposal, BPA has implemented the Principles using the Alternatives developed in the Principles. It assumed the costs that were used in the development of the Principles, for "other entities'" fish and wildlife O&M costs, BPA fish and wildlife O&M, and expenses for recovery of capital for historical and projected fish and wildlife investment of the COE, Reclamation, and BPA. BPA also assumed the generation effect for each of the 13 Alternatives as used in the development of the Principles. BPA then updated the 20-mill market price assumption used in the Principles to the same price forecasts used elsewhere in this rate case (*i.e.,* a projected market price which varies month-by-month). DeWolf *et al*., WP-02-E-BPA-39, at 27. This adjustment resulted in a slightly broader range of total costs ($430 million to $780 million), but did not alter the intent of the Principles. *Id.* at 27-28.

In their brief on exceptions, CRITFC/Yakama contend that BPA has not addressed their arguments that the range of fish and wildlife costs should be much higher to address new information. They take exception to BPA updating the market price of power but ignoring new information on costs. They argue this is arbitrary and capricious, and that it results in BPA not setting rates high enough to meet costs and assure payment to Treasury. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 14. This issue is addressed in ROD issue 5.4.3, *infra.*

Evaluation of Positions

BPA explained the reason for this adjustment:

> The update BPA made to the range of costs was isolated to the impacts on revenues and power purchases associated with system operations. We simply tried to reflect the market costs of power currently forecast for the rate period and more accurately model the interaction between the uncertainty over market prices and uncertainty over fish-related operational constraints.

DeWolf *et al*., WP-02-E-BPA-39, at 27.

Further, the second Principle itself states that the $438 million to $721 million was just the "currently estimated" range of costs. *Id.*

This update is simply a recharacterization of the portion of the revenue requirement that is attributable to implementation of the Principles. DeWolf *et al*., WP-02-E-BPA-39, at 28. Failure to update this range would result in failure to reflect the fish and wildlife costs that are in the revenue requirement, since purchase power is a significant component of revenue requirements. Purchase power for fish cannot be determined separately from purchase power for other reasons. *Id.* at 27. It is impossible to tell the difference between a power purchase for marketing reasons and a purchase due to an operational requirement of fish. *Id.* Power purchase costs in the revenue requirement are unchanged by this update. *Id.* at 28.

It is reasonable for BPA to update one set of data, the market prices, with the most recent data from the same sources, and not update other data (on fish and wildlife costs) where the source of that data is substantially less authoritative (*see* ROD section 5.4.4, *infra*).

As stated above, BPA was aware that the component of the financial impacts due to operational constraints could change as the market forecast was updated, and as BPA's ability to model the operational impacts improved. DeWolf *et al*., WP-02-E-BPA-39, at 27. Further, this expectation was conveyed to the parties. As CRITFC/Yakama stated, "Bonneville staff stated they would update this analysis (which assumed 20 mills) when they had completed additional analysis of the future market price of electricity using the AURORA model." Sheets *et al*., WP-02-E-CR/YA-05, at 4.

<u>Decision</u>

It was reasonable for BPA to update the range of costs associated with the Principles to reflect an updated market forecast.

5.4.3 <u>Fish and Wildlife Costs and Probabilities</u>

<u>Issue</u>

Whether BPA should use other estimates of fish and wildlife costs and probabilities rather than the fish and wildlife costs established in the Principles.

Parties' Positions

CRITFC/Yakama claim that the fish and wildlife decisions which will be made by the Federal Government "will almost undoubtedly increase Bonneville's costs . . . By not adequately addressing these costs in its proposal, Bonneville increases the risks that it will not be able to cover all of its costs or assure timely repayment to the Treasury." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 8. CRITFC/Yakama also argue that BPA has significantly underestimated the risks that it faces and has not included sufficient costs in its revenue requirements. *Id.* at 9. As a result, BPA has not set rates high enough to meet its costs and assure payment to Treasury. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 15. CRITFC/Yakama also allege that though a memorandum from William Stelle of NMFS calls for strengthening BPA's proposed contingencies [risk mitigation tools], BPA's proposal actually weakened several of them, including reducing PNRR, reducing the projected average ending reserves, and reducing the threshold for dividend distributions to BPA's customers. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 32. CRITFC/Yakama claim the direct program level of $179 million should not have been assumed to be a "high" alternative, but rather is a Columbia Basin Fish and Wildlife Authority (CBFWA) budget that should have been used as a "best estimate." *Id.* at 34-35; CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 15. They also claim BPA ignored evidence that more recent estimates were much higher than the range BPA considered, and that their evidence shows that the fishery managers believe that the more recent estimates are much more realistic. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 15. Ignoring this more realistic information was arbitrary and capricious. *Id*.

CRITFC/Yakama also state that BPA has erred by assuming a low probability for fish and wildlife alternatives that are most likely to comply with applicable Federal and environmental laws—CWA, ESA, F&WCA, and the Northwest Power Act. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 11. UCUT incorporates CRITFC/Yakama's position by reference. UCUT Brief, WP-02-B-UC-01, at 21.

In their brief on exceptions, CRITFC/Yakama contend that BPA has not addressed their arguments that the range of fish and wildlife costs should be much higher to address new information. They take exception to BPA updating the market price of power but ignoring new information on costs. They argue that this is arbitrary and capricious, and that it results in BPA not setting rates high enough to meet costs and assure payment to Treasury. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 14.

UCUT states that "[i]n its risk analysis, BPA used no objective criteria to assess its fish and wildlife costs and did not rely on expertise in fish and wildlife agencies." UCUT Brief, WP-02-B-UC-01, at 19. They claim that experts in matters of fish and wildlife and endangered species have testified that fish and wildlife options that are likely to be successful are the more costly options, and include options not listed in the 13 Alternatives. *Id.*

The Shoshone-Bannock Tribes states that "[b]oth the UCUT and Yakama Nation and CRITFC briefs point out that the risks after 2006 have not been adequately addressed by BPA's proposal. As such, the Shoshone-Bannock [sic] Tribes support and join in the positions taken by the Yakama Nation and CRITFC and the UCUT in their Initial Briefs." The Shoshone-Bannock

Tribes also agree with the suggested remedies of CRITFC/Yakama. Shoshone-Bannock Brief, WP-02-B-SH-01, at 9.

PPC argued that the range of $438-$721 million is adequate. Hansen *et al*., WP-02-E-PP-09, at 14. They also argue that certain other parties propose to revise BPA's risk assessment and mitigation techniques in order to accommodate "isolated and high cost fish and wildlife alternatives, chosen from those that the Principles direct should be equally weighted . . . BPA should reject such proposals for to do otherwise would violate its rate pledge and misrepresent the risk faced by the agency." PPC Brief, WP-02-B-PP-01, at 50. The PPC also stated that "BPA has done a reasonable job of considering the preliminary cost estimates of the fisheries agencies and tribes in evaluating the risks of high fish costs and of balancing this with other responsibilities." Hansen *et al*., WP-02-E-PP-09, at 13.

Further, PPC stated that parties' testimony in favor of increasing the range of potential costs is premature, because the fish and wildlife managers have yet to demonstrate that they can implement programs that are consistent with such benchmarks as PPC describes. Hansen *et al*., WP-02-E-PP-09, at 15.

PPC also stated:

> Even if high-cost alternatives are eventually adopted by Congress, it is not a foregone conclusion that BPA would be required to fund them all. An important consideration regarding who would pay for measures appears in section 4(h)(8)(B) of the Northwest Power Act . . . which provides that the NWPPC shall consider, in developing and adopting its fish and wildlife program, principles that include the following:
>
> > Consumers of electric power shall bear the cost of measures designed to deal with adverse impacts caused by the development and operation of electric power facilities and programs only.
>
> In view of the ongoing debates about salmon survival in the ocean, fresh water habitat measures unrelated to dams, and production and harvest measures, it is not clear which of the components of the highest cost alternatives would qualify for BPA funding under this provision of the Northwest Power Act.

Hansen *et al*., WP-02-E-PP-09, at 16.

<u>BPA's Position</u>

BPA is implementing the Principles in this rate case, DeWolf *et al*., WP-02-E-BPA-13, at 7, treating each of the 13 Alternatives as equally likely to occur. *Id.* at 10. The Principles are the product of extensive regional discussion and Administration direction. *See* section 2.3, *supra*; *see also* 64 Fed. Reg. 44318, 44320-21. The guidance the Principles provide is not an issue to be addressed in this rate case. *See* Burns and Elizalde, WP-02-E-BPA-08, at 4-5. *See also* 64 Fed. Reg. 44318, 44322-23.

While it is impossible to predict precisely BPA's fish and wildlife costs during the upcoming rate period, the range of costs represented by the 13 Fish and Wildlife Alternatives represents a reasonable range of costs given the variety of possible future alternatives for program implementation and operational impacts. DeWolf *et al*., WP-02-E-BPA-39, at 32.

Evaluation of Positions

CRITFC/Yakama claim the direct program level of $179 million should not have been assumed to be a "high" alternative, but rather is a CBFWA budget that should have been used as a "best estimate." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 35. As stated in cross-examination at Tr. 502-4, the $179 million level was an estimate that was presented to BPA during the development of the Principles, and it is prudent to consider a range as the Principles suggested when it defined the range between $100 and $179 million.

BPA's studies include estimates of the probabilities of having to sponsor a particular pattern of *costs*, including the timing of the costs (in the 2002-2006 period), not the probability of the eventual necessity of particular measures. DeWolf *et al*., WP-02-E-BPA-39, at 32. The range of costs represented by the 13 Fish and Wildlife Alternatives represents a reasonable range of costs, given the variety of possible future alternatives for program implementation and operational impacts, for the following reasons:

1. In a memorandum to the Regional Federal Executives, while discussing the "need for substantial increases in fish and wildlife program funding after 2000," William Stelle, Jr., of the NMFS stated "NMFS believes these costs have been adequately captured in the range of alternatives under analysis in the rate case." *Id*., Attachment 1, at 2.

   As CRITFC/Yakama point out, Mr. Stelle's memorandum encourages BPA to consider strengthening its risk contingencies, such as the CRAC. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 32. CRITFC/Yakama claim that BPA's proposal actually weakened several of the contingencies. *Id.* However, in BPA's rate proposal (filed subsequent to the date of Mr. Stelle's memorandum), BPA is increasing the threshold at which the CRAC would trigger, as well as increase the amount of revenue that BPA could receive under a CRAC. Additionally, BPA's starting reserves are forecast to be substantially higher than forecast at the time Mr. Stelle's memorandum was written. At the same time, BPA acknowledges that PNRR is recalibrated.

2. The range of fish and wildlife costs in the Principles is robust, in several ways.

   - Five of the 13 Alternatives include high-cost drawdown, even though it is unlikely that Congressional authorization and appropriations would occur in sufficient time for these costs to occur in FY 2002-2006.

   - Also, in implementing the Principles, BPA has assumed that Congress will appropriate capital funds consistent with the amounts and timing of investments projected in the 13 Alternatives. The level of appropriations required is nearly double the amount Congress has recently appropriated for Columbia River fish mitigation.

- Additionally, in developing the range, no test of scientific appropriateness has been applied to the activities included, and such a test might eliminate some of the activities.

DeWolf *et al*., WP-02-E-BPA-39, at 31.

3. BPA's studies assume BPA will pay all of the power-related costs contained in each of the alternatives. DeWolf *et al*., WP-02-E-BPA-39, at 30. With respect to the dam breaching alternatives, BPA has included all of the power-related costs for the breach investment, plus assumed that BPA will repay the entire original cost of the dam that is still owed. *Id.* However, following breach, power production may no longer be a project purpose for the breached dams. *Id.* Should Congress authorize dam breaching, it will necessarily look at who should pay the dam's original investment costs plus the costs for breaching. *Id.* With no power generation purpose, it is uncertain whether BPA will remain responsible for the same scope of project costs. *Id.*

4. BPA may not be responsible for all other costs contained in the 13 Alternatives. Currently the region is working to develop a Unified Regional Plan for fish and wildlife. DeWolf *et al*., WP-02-E-BPA-39, at 31. An element of this plan will include determining what BPA will be responsible for, as well as the responsibilities for the other Federal agencies, states, and local governmental bodies. *Id.* It is not a certainty that BPA will be charged for 100 percent of the costs, because the plan has not been completed or approved, and Congressional action has not been taken. *Id.*

For all these reasons, BPA agrees with the PPC that the range is adequate, Hansen *et al*., WP-02-E-PP-09, at 14; and that to revise BPA's risk assessment and mitigation techniques in order to accommodate isolated and high-cost fish and wildlife alternatives, chosen from those that the Principles direct should be equally weighted, misrepresents the risk faced by BPA. PPC Brief, WP-02-B-PP-01, at 50. CRITFC/Yakama have provided reasons they believe costs will be higher than BPA's proposal considered, CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 8, 15; and others have provided reasons they could be lower than BPA's proposal considered. BPA's proposal represents a reasonable balance between those who believe higher cost alternatives will be adopted and those who believe lower cost alternatives will be adopted. And, as pointed out by the NRU, "the financial assumption that these very high cost programs will be adopted is contrary to the 'Fish Funding Principles,' . . . and is beyond the scope of this case. The CRITFC/Yakama and NEC/SOS proposals should be rejected." NRU Brief, WP-02-B-NI-02, at 13.

UCUT states that "[i]n its risk analysis, BPA used no objective criteria to assess its fish and wildlife costs, and did not rely on expertise in fish and wildlife agencies." UCUT Brief, WP-02-B-UC-01, at 19. However, the Principles were developed in the Three Sovereigns Process, which included many individuals with expertise in fish and wildlife agencies. This process was described in an attachment to CRITFC/Yakama testimony entitled "Attachment Cost Estimates for Two Fish and Wildlife Alternatives":

> In the Spring and Summer of 1998, Federal, state, and tribal staff worked together through the Three Sovereigns Process to identify fish and wildlife alternatives. This effort identified 13 alternatives that ranged from the status quo operation with reduced river flows to modifying five dams to natural river conditions, implementing Clean Water Act (CWA) measures, increasing river flows, and adding new hatcheries to supplement natural production."

Lothrop, WP-02-E-CR-02, Attachment 3, at 5-6.

The Principles were developed "in consultation with constituents, customers, other Federal agencies, the Northwest Congressional delegation, and Columbia Basin Tribes in an extensive public involvement process." 64 Fed. Reg. 44318, 44321. As stated in the Revenue Requirement Study Documentation, Vol. 1, WP-02-E-BPA-02A, at 347, "a work group set up under the auspices of the 3 Sovereigns (now the Columbia Basin Forum) identified a list of individual actions or measures for each of the 13 Fish and Wildlife Alternatives." In the description of the System Configuration Alternatives, *Id.* at 369, it is explained that "the workgroup used as a starting point the system configuration alternatives that are being evaluated in the Plan for Analyzing and Testing Hypotheses (PATH) process and COE's Lower Snake Feasibility Study."

It is reasonable for BPA to adhere to the Principles, using the 13 Alternatives developed during the development of the Principles. If BPA were to revise BPA's risk assessment and mitigation techniques in order to accommodate isolated and high-cost fish and wildlife alternatives, chosen from those that the Principles direct should be equally weighted, it would be misrepresenting the risk faced by the agency. BPA's studies include estimates of the probabilities of having to sponsor a particular pattern of costs, including the timing of costs.

Decision

BPA will adhere to the Principles, using the 13 Alternatives developed during the development of the Principles.

5.4.4 Use of Other Fish and Wildlife Alternatives in Risk Analysis

Issue

Whether BPA should substitute or supplement its risk analysis with the analysis in the May 11, 1999, memorandum by regional staff of EPA, NMFS, USFWS, and Treasury.

Parties' Positions

CRITFC/Yakama argue that BPA should incorporate the May 11, 1999, staff level memorandum into its risk analysis. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 55-57; CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 16-18. The May 11, 1999, memorandum by regional staff of EPA, NMFS, USFWS, and a senior Treasury staff person was introduced in testimony by CRITFC/Yakama. Lothrop, WP-02-E-CR-02, at 3. They argue that the memorandum describes an "experimental management alternative for an aggressive stream of investment in fish and wildlife recovery measures during the interim period while the region and Congress consider Snake River dam removal." *Id.* They note that much higher costs are assumed with these proposals, especially during the 2002-2006 rate period. *Id.*

CRITFC/Yakama and UCUT argue in their initial briefs that an annual direct cost estimate of $325 million for fish and wildlife over the 2002-2006 rate period from the May 11 memorandum should be used; that cost assumptions as high as $390 million a year during the period should be analyzed; and these estimates are more reasonable than BPA's treatment of fish and wildlife costs over the 2002-2006 rate period. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 55-56. *See also* UCUT Brief, WP-02-B-UC-01, at 19-20. Finally, CRITFC/Yakama argue that BPA has ignored the May 11 memorandum and that BPA's failure to incorporate it into its risk analysis is arbitrary and capricious. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 18.

BPA's Position

Incorporation of the May 11, 1999, memorandum into BPA's analysis of fish and wildlife risks is unnecessary, because the fish and wildlife risks are adequately addressed by BPA's risk analysis. DeWolf *et al*., WP-02-E-BPA-39, at 31. BPA's risk analysis implements the Principles, while the May 11 memorandum lacks documentation and is contradicted, in part, by a subsequent May 26, 1999, memorandum from Mr. William Stelle, head of the Seattle office of the NMFS, which concludes that NMFS believes these costs have been adequately captured in the range of alternatives under analysis in the rate case. *Id*., Attachment 1, at 1. BPA has not ignored the May 11 memorandum in its fish and wildlife risk analysis. Rather, it has chosen to rely on a risk analysis and risk mitigation strategy which follow the Principles. BPA's actions meet the standard applicable to rate cases. *See* ROD section 1.4, *supra.*

Evaluation of Positions

Consistent with past practice and legislative mandate, BPA made substantial efforts in this rate case to enable a wide range of customers and stakeholders to participate in this process. *See e.g., BPA 2002 Proposed Wholesale Power Rate Adjustment, Public Hearing, and Opportunities for Public Review and Comment,* 64 Fed. Reg. 44318, 44323-24 (August 13, 1999); DeWolf *et al*., WP-02-E-BPA-39, at 20-24.

CRITFC/Yakama introduce the May 11, 1999, memorandum as part of a broader attack on BPA's treatment of fish and wildlife in its risk analysis. Lothrop, WP-02-E-CR-02, Attachment 3, at 1. *See also* DeWolf *et al*., WP-02-E-BPA-39, Attachment 1, at 1. The May 11 memorandum was authored by regional staff at EPA, NMFS, USFWS and senior staff at the U.S. Treasury. The Hearing Officer, following Motions to Strike by BPA and the PPC, limited use of the May 11 memorandum to "test or challenge a party's risk analysis." WP-02-O-14. Rather than comparing the information in the May 11 memorandum with BPA's Risk Analysis Study Documentation, WP-02-E-BPA-03A, and cross-examination testimony regarding risk analysis (Tr. 735-832, 1902-1949), CRITFC/Yakama argue that BPA should adopt in its risk analysis the contents of the May 11 memorandum. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 29-30. That is neither a test nor a challenge of BPA's risk analysis, as limited by the Hearing Officer. CRITFC/Yakama provide no explanation or citation to testimony for their assertions that, where Mr. Stelle's memorandum calls for strengthening the proposed contingencies, BPA actually weakened its risk package in its initial proposal. *Id.* at 32.

The May 11 memorandum is contradicted by the May 26, 1999, memorandum of Mr. Stelle, which states, "The timing of the rate case is out of sync with the timing of decisions regarding fish and wildlife operations through 2006. Options for those decisions are being examined currently through a number of regional processes, including the Federal Caucus. In the absence of final decisions, BPA has committed to setting its rates in a way that would not foreclose any of the options being considered." DeWolf *et al*., WP-02-E-BPA-39, Attachment 1, at 1. Mr. Stelle noted that while fish and wildlife costs might be higher after 2006, it is difficult to "pin down with accuracy" the range of out-year costs. *Id.* at 2. Mr. Stelle then stated, "NMFS sees no reason to conclude that BPA will not be able to cover anticipated costs." *Id.*

Mr. Stelle also contradicts the May 11 memorandum's claim that BPA's draft proposal (which was shared with representatives of the Federal agencies prior to commencement of the rate case) was inadequate. *See* DeWolf *et al*., WP-02-E-BPA-39, Attachment 1, at 1. The May 11 memorandum did not represent a Federal consensus on the issues it addresses, nor did the memorandum present new, reliable information.

CRITFC/Yakama attempt to repudiate the equal weighting of the 13 Fish and Wildlife Alternatives BPA has included in its rate proposal, but their effort is not supported by the record. Mr. Stelle's May 26 memorandum accepts BPA's ". . . firm and explicit assurances that it will meet these costs across a wide range of assumptions, with substantive supporting documentation. We see no basic remaining disagreement about these analyses or conclusions." DeWolf *et al*., WP-02-E-BPA-39, Attachment 1, at 1. Further, "BPA has committed to setting its rates in a way that would not foreclose any of the options being considered." *Id*. Mr. Stelle states, "Although it is impossible to predict with precision at this time what a fish and wildlife budget agreement thorough 2006 would look like, the range of costs BPA could cover with its contingent funding proposal appears adequate to cover the likely range of fish and wildlife costs through 2006." *Id.* at 2.

Further, CRITFC/Yakama's efforts to argue against the equal weighting of the 13 Fish and Wildlife Alternatives through the May 11 memorandum is outside the scope of the rate case as described in the Federal Register and as limited by the Hearing Officer, and should be disregarded. BPA's Rules of *Procedure Governing Rate Hearings*, §1010.11(a)(2); §1010.13(b) and §1010.13(c); Hearing Officer Order, WP-02-O-14.

Finally, the May 11 memorandum cited by CRITFC/Yakama lacks substance and reliability on its face. It is unsigned. It has not been finalized. It was not authenticated and was outside the public records exception to hearsay rules. Federal Rules of Evidence 801 and 803(8). *See also* DeWolf *et al*., WP-02-E-BPA-39, Attachment 1, at 2.

Each of the participants who offer alternatives for BPA to consider as it meets its fish and wildlife obligations offers choices that conflict with other choices. BPA must balance these alternatives with other interests and obligations to produce its rates. This is consistent with BPA's statutory charge. 16 U.S.C. §839e(i). However, BPA is forced by the ratesetting process and its obligations to the region to accept some positions and reject others. *See, e.g., Association* *of Public Agency Customers v. Bonneville Power Administration (APAC v. BPA)*, 126 F.3d 1158, 1174-76 (9th Cir. 1997). Congress has granted BPA an unusually expansive mandate to operate with a business-oriented philosophy, and courts have found it wise to defer to BPA in matters such as these, "especially when the agency is responding to unprecedented changes in the market resulting from deregulation." *APAC v. BPA*, at 1, 171. These changes continue to confront BPA and the wholesale electric power industry. *See, e.g.*, Burns and Elizalde, WP-02-E-BPA-08, at 2-8. Changes include implementation of FERC's functional separation orders (*Id.* at 2), changing market conditions (*Id.* at 2-3), and implementation of the Principles (*Id.* at 4-6). BPA's risk analysis, including its decision not to revise its risk analysis and to retain a "keep the options open" fish and wildlife strategy, reflects a reasonable approach to these changes in the industry and the Columbia River Basin. The decision not to modify BPA's risk analysis by including values and concepts presented in the May 11, 1999, memorandum was appropriate, because BPA's risk analysis keeps the fish and wildlife options open. Thus, BPA has not ignored the May 11 memorandum; it has chosen to rely on a risk analysis and risk mitigation strategy which follow the Principles, in light of the obvious limitations of the May 11 memorandum. BPA's decision not to revise its risk analysis to reflect information contained in the May 11 memorandum is reasonable given the current business environment.

BPA's fish and wildlife risk analysis and risk mitigation, including its treatment of the May 11 memorandum, are supported by substantial evidence and are not arbitrary and capricious. *See* ROD, section 1.4, *supra*.

Decision

BPA made appropriate judgments when it did not revise its risk analysis to reflect the information contained in the May 11, 1999, unsigned, draft memorandum by regional staff of EPA, NMFS, USFWS, and a senior Treasury staff person.

5.4.5 Fish and Wildlife Obligations

Issue

Whether BPA has inappropriately included funds to cover costs and risks, including fish and wildlife costs and risks, that might be incurred in a subsequent rate period (i.e., post-2006).

Parties' Positions

The IOUs claim that BPA is improperly accumulating excess reserves in this case in order to pay for fish costs for the post-2006 rate period. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 52. They claim, in their brief on exceptions, that BPA's Draft ROD fails to reconcile its conclusion with BPA's prior statements to NEC/SOS that its "unprecedented expected reserves of $1.4B by 2006 positioned it to cover most of the 18 fish cost scenarios post-2006." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 40. "While the [IOUs] would like to believe that BPA is not improperly accumulating reserves, BPA's assurances that it is not so doing--in the face of its unprecedented ending reserves--offer no comfort when BPA has made statements to others that reveal a different agenda." *Id.*

CRITFC/Yakama argued that BPA is not including post-2006 costs. "The proposed rates are designed to cover Bonneville's costs and maintain a high Treasury payment probability in this rate period and next. It is common practice for a business to position itself to address future risk by creating reserves necessary to accommodate that future risk." Sheets *et al*., WP-02-E-CR/YA-05, at 10.

CRITFC/Yakama also assert that fishery managers agree that fish and wildlife costs will increase significantly after 2006. A significant portion of this added cost will be paying the long-term debt service on fish and wildlife protection measures that are implemented during the 2002-2006 rate period. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 46-47.

BPA's Position

BPA's rates are being set to recover costs for the FY 2002-2006 period. DeWolf *et al*., WP-02-E-BPA-39, at 20. Adopting a mechanism to distribute during the FY 2002-2006 period some of the revenue generated by those rates if circumstances show that it is not all needed does not shift any post-2006 costs into the FY 2002-2006 period. *Id.* Post-2006 costs are not driving the 2002 rates. *Id.*

Evaluation of Positions

Only projected costs for this rate period are included in revenue requirements. Only risks in these years are included in the risk analysis. The risk mitigation tools (starting reserves, PNRR, and CRAC) are all designed to address only the risks in this rate period. And the 88 percent TPP that the tools are designed to meet are applicable to this rate period only. While it is true that the expected value of reserves at the end of 2006 is higher than BPA is starting with, this is not an argument or demonstration that BPA is pulling costs forward. *See* ROD section 7.2. The fact that BPA has observed and discussed the expected value of reserves at the end of 2006 that result from implementing BPA's risk mitigation strategy does not disprove BPA's assertion that the high ending reserves result from the risk mitigation strategy and not from an intention to accumulate "excess reserves in this case in order to pay for fish costs for the post-2006 rate period," as the IOUs claim. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 52.

In their brief on exceptions, CRITFC/Yakama take exception to BPA's inadequate treatment of its obligation to position itself to meet higher environmental costs after 2006. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 19. The result will likely be that BPA will not be able to meet its costs and assure repayment to Treasury in the next rate period. *Id*. This is not consistent with Principle 4, or BPA's Treaty and trust obligations. *Id*. This issue is addressed in ROD section 5.4.7, *infra.*

Decision

BPA has not included funds to cover costs and risks, including fish and wildlife costs and risks, that might be incurred in a subsequent rate period (i.e., post-2006).

5.4.6 Principles Nos. 1, 3, and 5

Issue 1

Whether BPA's 2002 rates meet both Principle 1 ("Bonneville will meet all of its fish and wildlife obligations once they have been established, including its trust and treaty responsibilities") and Principle 3 ("Bonneville will demonstrate a high probability of Treasury payment in full and on time over the 5-year rate period").

Parties' Positions

CRITFC/Yakama argue that the lowest-cost alternatives are unlikely to meet ESA standards and to ensure sustainable harvests or populations. CRITFC/Yakama claim that breach alternatives provide a significantly higher likelihood of recovery, and hence, sustainable harvest for Tribal fisheries. CRITFC/Yakama state that these alternatives also have a higher likelihood of meeting Principle No. 1. CRITFC/Yakama argue that BPA's risk mitigation package should be adjusted to account for the higher likelihood that these more expensive alternatives are more likely to be implemented than the low-cost alternatives. Sheets *et al*., WP-02-E-CR/YA-05, at 20.

CRITFC/Yakama state that Alternative 13, if chosen, would put BPA's TPP at about 65 percent, which would violate Principle No. 3. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 21. It would also mean that BPA would be unable to fully fund the fish and wildlife measures, which violates Principle No. 1. *Id.* at 21-22. CRITFC/Yakama claim that because BPA's proposal does not address the risk that Alternative 13 is the most likely to provide for fish and wildlife recovery, the proposal is deficient and should be changed to comply with Principles Nos. 1 and 3. *Id.* at 22.

In their brief on exceptions, CRITFC/Yakama take exception to BPA's assertion that it is meeting these Principles. They argue that their brief clearly demonstrates that BPA cannot meet the alternatives that are likely to address Treaty and legal obligations and still meet its repayment probability for Treasury. They claim that BPA has not addressed the substance of these comments. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 10.

On the other hand, PPC stated that BPA's proposed rates for the 2002-2006 rate period are not intended to collect revenues that will recover the costs associated with any single alternative. Hansen *et al*., WP-02-E-PP-09, at 13.

CRITFC/Yakama also state that BPA appears to be saying that its rate scheme meets the Principles as long as BPA does not have to fulfill Treaty and trust obligations and meet its responsibilities under the CWA. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 45.

The Shoshone-Bannock Tribes support and join in the positions and remedies suggested by CRITFC/Yakama and UCUT, and assert that CRITFC/Yakama:

> . . . have successfully shown that the Principles cannot be met through BPA's scheme. Further, they have successfully shown the deficiencies of BPA's

> proposal with meeting their treasury repayments and the inconsistency with the Fish and Wildlife MOA. Both the UCUT and Yakama Nation and CRITFC briefs point out that the risks after 2006 have not been adequately addressed by BPA's proposal.

Shoshone-Bannock Brief, WP-02-B-SB-01, at 9.

BPA's Position

BPA's 2002 rates meet both Principles Nos. 1 and 3. As a Federal agency, BPA shares the Government's trust responsibility to Indian tribes. BPA fulfills its trust responsibility by working with the PNW region's tribes in the manner prescribed by DOE and BPA tribal policies and by fully complying with the laws governing its activities, including the Northwest Power Act, ESA, and NEPA. DeWolf *et al*., WP-02-E-BPA-39, at 33. *See also,* ROD section 18.2.2.

For purposes of the 2002 rates, BPA is implementing Principle No. 1 by ensuring that rates and risk mitigation measures are sufficient to recover the costs of future decisions on system reconfiguration and associated operations. DeWolf *et al*., WP-02-E-BPA-13, at 11. This is accomplished by:

- ensuring that revenue requirements, the repayment schedule, and the risk analysis take into account the full range of potential fish and wildlife costs represented by the 13 Fish and Wildlife Alternatives, without prejudice of one alternative over another;

- identifying and modeling all significant risks, and by adopting a very high standard for recovering costs on time and in full; and

- designing risk mitigation measures that meet the standard.

See DeWolf *et al.*, WP-02-E-BPA-13, at 11, and Volume 1, Revenue Requirement Study Documentation, WP-02-E-BPA-02A, at 346.

The risk mitigation tools in this rate period are designed to achieve an 88 percent probability that all payments to the U.S. Treasury will be made on time and in full over the five-year rate period. DeWolf *et al*., WP-02-E-BPA-39, at 11.

Evaluation of Positions

CRITFC/Yakama argue that BPA's proposal does not meet Principles Nos. 1 and 3. They contend that the more expensive, breaching alternatives are more likely to meet Principle No. 1, and BPA is not giving those alternatives a sufficiently high probability of occurring in its risk analysis. Therefore, they assert, BPA is not meeting Principle No. 1. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 21. They also argue that BPA's proposal fails to meet Principle No. 3 because, for the Alternatives CRITFC/Yakama believe are most likely to meet treaty and trust obligations, the TPP is lower than 88 percent. *Id*. at 22.

However, PPC notes that BPA has stated that it is committed to meeting its future fish and wildlife expenses whatever they are. Hansen *et al*., WP-02-E-PP-09, Attachment B, at 1. BPA believes it is implementing Principle No. 1 by modeling the 13 Alternatives as called for in the Principles. BPA has committed itself clearly and publicly, with the express endorsement of the Administration, to meeting its fish and wildlife obligations once they have been determined, without qualifications as to the magnitude of the obligations. Volume 1, Revenue Requirement Study Documentation, WP-02-E-BPA-02A, at 361; Hansen *et al*., WP-02-E-PP-09, at Attachment B. The 13 Alternatives represent a set of assumptions, a forecasting convention, to establish assumptions for purposes of setting rates. DeWolf *et al*., WP-02-E-BPA-13, at 10. These assumptions are intended to establish a reasonable range for a specific set of future costs, consistent with statutory directives that govern BPA's ratemaking. DeWolf *et al.,* WP-02-E-BPA-39, Attachment 2. Such a forecast, however, does not define or circumscribe the actual obligations that will be created in the upcoming rate period, regardless of the source of those obligations or how they may arise. *Id.* Nor does such a forecast prevent or preclude BPA from meeting its future obligations. *Id*. And, even if BPA misses a payment to Treasury, it does not mean that funding for fish and wildlife programs or measures is being reduced. DeWolf *et al.*, WP-02-E-BPA-13, at 14. Rather, it means that repayment or reimbursement is delayed for funding that already has been expended. *Id*.

BPA also believes it is meeting Principle No. 3. BPA's modeling of forecasted costs and revenues, risks, and risk mitigation tools results in an 88 percent TPP. "The 88 percent Treasury payment probability standard is based on a complete package of risks and risk mitigation tools as well as the rest of the PBL rate proposal." Tr. 500.

CRITFC/Yakama misunderstand Principle No. 3. It commits BPA to achieve a high TPP in the proposal; it does not commit BPA to maintaining that same TPP no matter what events occur subsequent to the rate case. When CRITFC/Yakama state that under a particular alternative "Bonneville's TPP probability would reduce to 65 percent," CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 27; it is referring to an analysis that BPA and other Federal agencies considered prior to BPA's initial proposal. Sheets, WP-02-E-CR/YA-01, Attachment 1, at 5-6. The analysis is entitled "Approximate 2002-2006 and 2007-2011 Impacts of 13 (18) F&W Alternatives" and includes the 'Conditional TPPs' for 2002-2006 associated with each of the 13 Fish and Wildlife Alternatives. *Id.* The Conditional TPP for Fish and Wildlife Alternative 13u shows a Conditional TPP of 65 percent. *Id.* These Conditional TPPs together average 88 percent, but vary depending upon the severity of the mitigation measures encompassed by different Fish and Wildlife Alternatives, some higher and some lower. *Id.* BPA applies its 88 percent TPP standard to the full range of uncertainties that are observable at the time the rate case studies are conducted, Volume 1, Revenue Requirements Study Documentation, WP-02-E-BPA-02A, at 280; not to an individual alternative. *See* ROD section 7.2, Issue 4, *infra*.

As PPC states, BPA's rates for the 2002-2006 rate period are not intended to collect revenues that will recover the costs associated with any single alternative. Hansen *et al*., WP-02-E-PP-09, at 13. Applying an 88 percent TPP standard to a single alternative would not be consistent with the Principle wherein the TPP goal is associated with 13 equally weighted alternatives. "If, for instance, we know for sure one of those particular measures was going to be the fish and wildlife plan, that would be a very substantial change to Bonneville's risk profile and if Bonneville made no change in its risk mitigation package it's very likely the treasury payment probability would no longer be 88 percent. That's true for each of the 13 alternatives, however . . . [i]f we knew for sure one of them would be chosen, that uncertainty then is eliminated and if no other adjustments were made the treasury payment probability would probably be quite different." Tr. 501. PPC also states that "BPA would further violate its rate pledge goal if it implemented certain parties' recommendations that BPA increase its rates in order to afford high cost fish and wildlife alternatives." Hansen *et al.*, WP-02-E-PP-09, at 18. "The witness [CRITFC/Yakama] is effectively proposing a 15-28 percent increase over BPA's initial proposal which means that BPA would further violate its rate pledge and power customers would see a significant increase in power costs for fish and wildlife costs that have not yet been adopted as BPA's budget." *Id.* at 20. Given what we know now, and taking into account the uncertainties, risks and risk mitigation tools, BPA is proposing rates with an 88 percent TPP.

Decision

BPA's 2002 power rates meet both Principle 1 ("Bonneville will meet all of its fish and wildlife obligations once they have been established, including its trust and treaty responsibilities") and Principle 3 ("Bonneville will demonstrate a high probability of Treasury payment in full and on time over the 5-year rate period"). BPA is reflecting the 13 Alternatives and assuming each is equally likely to occur, and thus is keeping the options open. BPA is setting rates to recover the range of costs associated with the 13 Alternatives, and is demonstrating an 88 percent TPP.

Issue 2

Whether Principles 1, 3, and 5 are jointly incompatible and pose a mathematical dilemma.

Parties' Positions

In their brief on exceptions, Alcoa/Vanalco argue that there is a mathematical dilemma created by BPA: it may not be possible to meet an 80 percent TPP [Principle No. 3], meet every fish and wildlife cost that may be imposed on BPA during the rate period [Principle No. 1], and keep the rate pledge by setting the PF rate at 1996 levels [Principle No. 5]. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 16. Alcoa/Vanalco argue that BPA has not attempted to clarify whether it will be able to meet Treasury payments if fish and wildlife costs exceed the highest of the 18 fish and wildlife scenarios. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 16. Therefore, they contend, BPA cannot prove its proposed rates will allow it to meet its Treasury payments, and FERC cannot then make the affirmative findings necessary to approve rates proposed. *Id*. at 16-17.

BPA's Position

Principles Nos. 3 and 5, meeting a high TPP (88 percent) (*see* ROD section 7.2) and keeping 2002-2006 rates at the same average level as current rates (*see* ROD section 2.2), will be satisfied upon conclusion of this rate case. Principle No. 1, that BPA will meet its fish and wildlife obligations, is a long-term commitment that will be satisfied as BPA's fish and wildlife obligations are determined and as they are met throughout the 2002-2006 rate period. *See* Issue 1, *supra*. Because the three Principles refer to different points in time, there is no mathematical dilemma.

Evaluation of Positions

The first factor listed by Alcoa/Vanalco is TPP, Principle No. 3, which will have been determined by the conclusion of the power rate case. BPA's proposal does demonstrate that BPA will have an 88 percent TPP. *See* Volume 1, Chapter 12, Revenue Requirement Study Documentation, WP-02-E-BPA-02A. The third factor listed by Alcoa/Vanalco is the rate pledge, Principle No. 5. Satisfaction of this Principle will also have been made at the conclusion of the power rate case. BPA's proposal does satisfy Principle No. 5. *See* ROD section 2.2. At the point the TPP and the rates are determined, the fish and wildlife costs are still uncertain, and BPA will not yet have had to make any payments to the Treasury for the 2002-2006 period. At a later time, a fish and wildlife plan may be adopted and BPA will have to meet its fish and wildlife obligations, and at other times BPA will need to pay the Treasury. These times will all be after the conclusion of the rate case, and by then Principles Nos. 3 and 5 will have been satisfied.

BPA does not need to prove that its rates will enable it to meet all Treasury payments; according to the TPP standard that BPA has been applying with FERC's approval to its rates since the 1993 rate case, BPA needs to establish that its rates are sufficient to achieve a specified *probability* of meeting all of its payments, in light of many uncertainties. *See* Volume 1, Revenue Requirement Study Documentation, WP-02-E-BPA-02A, at 275. In this rate case, BPA will keep the rate pledge while achieving an 88 percent TPP, which explicitly acknowledges that subsequent events such as regional adoption of an extremely expensive Fish and Wildlife plan or the occurrence of several dry years in a row could result in a Treasury payment deferral. However, even with a deferral, BPA will still meet its fish and wildlife obligations. But there is an 88 percent probability that a Treasury payment deferral will not occur in even one of the five years in the 2002-2006 rate period.

A Treasury payment deferral during 2002-2006 would not retroactively violate Principles Nos. 3 or 5, which are satisfied at the end of this rate case, nor would it cause a violation of Principle No. 1 by preventing BPA from meeting its fish and wildlife obligations. "Inasmuch as payments to Treasury represent the lowest priority in BPA's priority of payments, the average amount of these payments is large, and the level of TPP is very high, these higher priority costs [*e.g.*, fish and wildlife expenses] are virtually guaranteed to be recovered, which is to say, the availability of cash to fund these costs is certain." DeWolf *et al.* WP-02-E-BPA-13, at 13.

What can appear to be a dilemma if only one time point is assumed can be seen to be free of logical contradictions once the distinctions among different points in time are recognized.

Decision

Principles Nos. 1, 3, and 5 are mutually compatible and do not pose a mathematical dilemma.

5.4.7 Principle No. 4

Principle No. 4 states "Given the range of potential fish and wildlife costs, BPA will design rates and contracts which will position BPA to achieve similarly high Treasury payment probability for the post-2006 period by building financial reserve levels and through other mechanisms." Volume 1, Revenue Requirement Study Documentation, WP-02-E-BPA-02A, at 355.

5.4.7.1 Change Risk Mitigation Package to Achieve 90 Percent Probability of $500 Million Ending Reserves

Issue

Whether BPA should change its risk mitigation package to achieve a 90 percent probability of having at least $500 million in reserves at the end of FY 2006 in order to meet increasing fish and wildlife funding uncertainty and to meet Principle No. 4.

Parties' Positions

The Oregon Public Utility Commission (OPUC) argues that to handle increasing uncertainties that carry over into the next rate period, and satisfy Principle No. 4, BPA needs to adopt final rates, including a risk mitigation package, that collect revenues sufficient to demonstrate a 90 percent probability of having about $500 million in ending reserves in FY 2006. OPUC Brief, WP-02-B-OP-01, at 9.

BPA's Position

BPA believes its rate proposal "positions BPA's power function reasonably well to be able to obtain a 'similarly high' TPP for the post-2006 period, through such mechanisms as potential rate increases, a planned build-up of reserves, potential rate adjustment mechanisms, and other actions that can be taken between now and 2007." DeWolf *et al.*, WP-02-E-BPA-39, at 34-38.

BPA's proposal implies a 70 to 80 percent chance of having at least $500 million in reserves at the end of 2006. *Id*. at 38. Increasing this probability would require: (1) abandoning the 88 percent standard; and (2) either: (a) making the CRAC significantly more powerful, which would increase the frequency of CRAC triggering and the magnitude of the CRAC revenue increases; or (b) raising rates significantly. *Id*. Either of these would reduce rate stability. *Id.* Rate stability is a key BPA goal in this rate case. *Id*.

BPA's long-standing risk mitigation standard is an 88 percent TPP. DeWolf *et al.*, WP-02-E-BPA-39, at 22.

Evaluation of Positions

OPUC claims that BPA's proposed risk mitigation package allows an expected value of reserves under $600 million 30 percent of the time, which imperils Principle No. 4 by leaving reserves too low too often. They argue that BPA has offered no substitute objective criteria. OPUC

Ex. Brief, WP-02-R-OP-01, at 4. However, BPA's 2002 rates have sufficient risk mitigation tools to meet increasing fish and wildlife funding uncertainty as well as to meet Principle No. 4. *See* ROD section 5.4.7.2, Issue 6, *infra*. BPA measures the ability of its rates to meet its obligations with its longstanding risk mitigation standard of 88 percent TPP. DeWolf *et al.*, WP-02-E-BPA-13, at 21. The 2002 rates, designed under this standard, will produce unprecedentedly high TPP, *Id.* at 12, and the expected value of ending reserves is also very high. DeWolf *et al.*, WP-02-E-BPA-39, at 15. OPUC's proposal, however, would result either in a significant rate increase or a significantly more powerful CRAC, and therefore more rate instability. *Id*. at 38. The parties have proposed a new risk mitigation criterion, but have failed to demonstrate that BPA's position is unreasonable.

See also ROD section 7.7, *infra*.

<u>Decision</u>

BPA's 2002 power rates meet Principle No. 4, and result in lower and/or more stable rates than OPUC's proposal. BPA will not change its risk mitigation package, which achieves an 88 percent TPP, in favor of adopting a goal of having a 90 percent probability of having $500 million in ending reserves in FY 2006.

5.4.7.2 <u>Treasury Payment Probability (TPP) "Policy"</u>

<u>Issue 1</u>

Whether BPA's 1993 10-Year Financial Plan requires that BPA demonstrate in its 2002 rate case that it can achieve a 77 percent TPP for a 10-year period.

<u>Parties' Positions</u>

Several parties argue that BPA has a policy or standard requiring BPA to demonstrate that it can meet a 10-year TPP of 77 percent, and that this requires BPA to demonstrate in this rate case that it will be able to achieve an 88 percent TPP for 2007-2011. OPUC states that "the ability to meet the 10-year 77% TPP requires that BPA will be freely able to increase rates between rate periods to achieve an 88% TPP . . ." OPUC Brief, WP-02-B-OP-01, at 3. OPUC claims that BPA refuses to address the real point of OPUC's argument to measure the post-2006 financial viability of its rate proposal by using the 77 percent 10-year TPP "standard" "intended" by BPA's long-standing 1993 financial policy, and they urge BPA to use this "standard" as a measure to judge whether it has met Principle No. 4. OPUC Ex. Brief, WP-02-R-OP-01, at 5.

NEC/SOS state that "[t]he 1993 policy standard (which in turn came from BPA's June 1992 10-year Financial Plan), which BPA is using in this rate proceeding, requires that rates must result in a 77 percent Treasury Payment Probability ("TPP") over a ten year period." NEC/SOS Brief, WP-02-B-NA/SA-01, at 2. "For this 5-year rate case, as in 1996, Bonneville is again proposing setting rates for the first of two 5-year rate periods, each of which must meet an 88 percent TPP to be equivalent to the 10-year standard." *Id.* NEC/SOS argue that BPA can no longer simply assume--like it could in 1993--that it will be able to establish rates sufficient to meet the 88 percent TPP standard for the second rate period. BPA must instead produce credible evidence that this will be possible. *Id.* at 13; NEC/SOS Brief, WP-02-B-NA/SA-01, at 3. NEC/SOS argue that BPA's denial of this criterion capriciously flies in the face of substantial testimony by "OPUC, CRITFC and ourselves, and numerous admissions to the contrary by BPA . . ." NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 6.

CRITFC/Yakama state that BPA's proposal "has adopted the 1993 Bonneville policy of a 77 percent Treasury Payment Probability over a ten-year period." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 9. "CRITFC and the Yakama Nation hereby incorporate by reference the analysis and arguments of [NEC/SOS] and [OPUC], WP-02-B-NA-01 and WP-02-B-OP-01 respectively, concerning Bonneville's treatment of the 1993 standard for assurance of Treasury repayment." *Id.*

BPA's Position

This is an issue that was initially raised in the NEC/SOS brief. Neither BPA nor the parties had an opportunity to test NEC/SOS's evidence through discovery or cross-examination.

The 10-Year Financial Plan standard adopted in the 1993 ROD stated "[a]s a long-term policy, BPA will plan to set its rates to maintain financial reserves sufficient to achieve a 95 percent probability of meeting Treasury payments in full and on time for each two-year rate period. Thus, in subsequent rate cases . . . BPA will establish rates consistent with the long-term policy of achieving the 95 percent Treasury payment standard for each 2-year rate period." *See* 1993 ROD, WP-93-A-02, at 72. In developing this standard, BPA examined the numeric significance of adopting the 95 percent rate period standard over a 10-year period. "This standard *results in* the probability of continued success over 10 years (five 2-year rate periods) of $(.95)^5$, or a 77 percent probability of meeting all payments over 10 years" (emphasis added). *Id.* at 69. In the 1996 rate case, this 95 percent two-year standard was converted to an equivalent 88 percent probability of making all five U.S. Treasury payments in a five-year period. 1996 Revenue Requirement Study, WP-96-FS-BPA-02A, at 555-556.

BPA's position is that there is no 77 percent standard; BPA's TPP standard applies to a single rate period.

Evaluation of Positions

The record is sparse on this issue because it was introduced for the first time in the parties' briefs. Neither BPA, nor other parties have had an opportunity to test this new evidence through discovery or cross-examination. However, there is nothing in the record of this rate case or previous ones indicating that 77 percent has been treated by BPA or the parties as anything except: (1) an illustration of the long-term impact of the 95 percent two-year standard; and (2) a number useful in translating the 95 percent standard to rate periods of lengths other than two years. Note that the cite above from the 1993 ROD, wherein the standard was adopted, states that the 95 percent two-year standard *results in* the probability of success over 10 years. 1993 ROD, WP-93-A-02, at 69. The standard set in the 10-Year Financial Plan was for a two-year period. In the 1996 case where it was converted to a five-year standard, there was no mention of a calculation for a 10-year TPP.

The 95 percent TPP Standard adopted in the 1993 rate case was a standard that applied to a single rate period. BPA illustrated the long-term meaning of such a policy by means of the calculation that five statistically independent consecutive rate periods would have a combined 10-year TPP of 77 percent. BPA did not ever suggest that this illustration bound BPA in each rate case to prove that it would be able to achieve comparable TPPs throughout the remainder of the 10-year period that begins with the rate period under consideration. Nothing in the record indicates that BPA or any party undertook calculations of 10-year TPPs in any previous rate case, or that BPA or any party interpreted the 77 percent 10-year number as a criterion to be applied to the question of the adequacy of rates, contrary to OPUC's contention that the 10-year 77 percent TPP was an intended standard. The 77 percent 10-year figure has been used only as an illustration of the long-term impact of the TPP standard, and as a means for determining for rate periods of other than two years what TPP level would be equivalent to the 95 percent two-year TPP standard for ensuring payments to the Treasury.

From the 10-Year Financial Plan:

> BPA's Financial Plan includes a long-term financial policy that BPA shall establish rates to maintain a level of financial reserves sufficient to achieve a 95 percent probability of making its U.S. Treasury payments in full and on time for each two-year rate period. 1993 Revenue Requirement Study, WP-93-E-BPA-02, at C12. The 95 percent probability policy provides that, in achieving the 95 percent probability standard, rates will be set to include recovery of any inherent downward bias in BPA's expected cash-flow distribution, taking into account normal operating risks. *Id.;* Marshall and Armstrong, WP-93-E-BPA-10, at 4. This long-term Treasury payment standard recognizes BPA's responsibility to act in a manner that ensures its ability to fulfill its legally mandated responsibilities required under the Northwest Power Act in a sound and business-like manner. *Id.* Meeting these responsibilities necessitates that a very high priority be placed on ensuring BPA's ability to meet its annual payments to Treasury with a high level of certainty in order that BPA is able to ensure its continued access to the financial resources needed to carry out its responsibilities. *Id.* The Financial Plan provides that during the FY 1994-95 rate period, the 95 percent long-term probability standard will be phased in on a one-time-only basis. 1993 Revenue Requirement Study, WP-93-E-BPA-02, at C12. Thus, it is BPA's intent that for rate periods subsequent to FY 1994-95, the long-term policy standard will be applied and implemented to result in rates that achieve the full 95 percent probability standard.
>
> In developing a long-term Treasury payment standard, BPA considered the long-term implications of establishing a Treasury payment standard that would be applied to each two-year rate period. *Id.* at 5. In doing so, BPA examined the numeric significance of adopting the 95 percent rate period standard over a 10-year period. "This standard results in the probability of continued success

> over 10 years (five two-year rate periods) of (.95)5, or a 77 percent probability of meeting all payments over 10 years." *Id.* BPA believes that the 77 percent long-term Treasury payment result is reasonable given its intent to evaluate and establish rates every two years, and that selection of this long-term standard balances the Treasury's interest in receiving its payments in full and on time and BPA's customers' desire for the lowest rates possible. *Id.* at 5-6.
>
> First, the Joint Customers' claim that BPA has adopted a "new interpretation" of the 95 percent probability Treasury payment standard is simply incorrect. The BPA testimony cited by the Joint Customers contains no such characterization of the 95 percent probability standard as a "new interpretation." Marshall and Armstrong, WP-93-E-BPA-20, at 6. "On the contrary, BPA's Proposed 10-Year Financial Plan, published in June 1992, stated the 95 percent probability standard as follows: '*BPA proposes that the 95 percent Treasury repayment standard over each 2-year rate period that was selected for the current 1992-93 rate period be continued and that it be applied to each relevant rate period.*"' *Id.* In that same document, "BPA further explained the interpretation of the 95 percent rate period Treasury payment standard, stating that '[a]pplication of this repayment probability standard would result in BPA making its full annual Treasury payments in both years in at least 95 out of 100 2-year rate periods."' *Id.*
> In addition, in the Proposed 10-Year Financial Plan, BPA explained the long-term statistical significance of adopting the 95 percent probability rate period standard. *Id.* at 7. "BPA stated that '[a]pplying the 95 percent standard over different time periods significantly affects the probability that BPA would meet its Treasury payments in any single year, and in all 10 years of any consecutive 10-year period."' *Id.* "Under BPA's proposal, the probability of continued success over a 10-year period of timely Treasury payment with a target 2-year rate period probability of 95 percent is 77 percent. By contrast, the probability of continued success of timely Treasury payment over a 10-year period decreases to only 60 percent with a target annual probability of 95 percent." *Id.* Thus, the Proposed 10-Year Financial Plan (June 1992) clearly represented the 95 percent standard as a two-year *rate period standard*, not an average standard, and laid out the statistical significance of that standard over a 10-year period.

1993 ROD, WP-93-A-02, at 69-70.

In the 1996 rate proposal, BPA stated:

> The Long-Term Financial Risk Mitigation Policy sets a standard of achieving a 95 percent probability of making all Treasury payments during a two-year rate period. The reasonableness of this standard was assessed in the 1993 Final Rate Proposal, Administrator's Final ROD, WP-93-A-02 at pages 70-72. In applying this standard over a 10-year period (five two-year rate periods), BPA would achieve a 77 percent probability of making all 10 payments. This is illustrated by the calculation of .95 * .95 * .95 * .95 * .95 = .77.

> For this five-year rate proposal, the 95 percent (two-year) standard was translated into a five-year standard by determining what probability of making all payments in a five-year period would be needed to yield a 77 percent probability over a 10-year period. In other words, if a 10-year period consisting of two five-year rate periods were to have an overall probability of 77 percent of making all payments, what probability for *each* five-year rate period would be required? This required five-year probability is 88 percent. Like the 95 percent (two-year) standard, this 88 percent (five-year) standard would result in a 77 percent probability of making all payments in a 10-year period. This is illustrated by the calculation of .88 * .88 = .77. Thus, the five-year percentage standard that is equivalent to the 95 percent standard of the 10-Year Plan is shown to be 88 percent. Unless noted otherwise, later references in this testimony to "Treasury payment probability" will mean the probability of making all five payments within the FY 1997-2001 rate period.

Arnold *et al*., WP-96-E-BPA-15, at 3.

The only TPP *standard* or *policy* is for a single rate period; the references to 10-year periods and to 77 percent are clearly illustrations of the long-term impact of the single rate period standard, and not intended as standards or policies. NEC/SOS argue that it was not the policy of the 1993 ROD to establish simply one two-year rate period. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 6. However, as explained *supra*, the policy established in 1993 was that, during any ratesetting process, a TPP for the rate period at issue should meet the standard, and that this should be done long-term, *i.e.*, during each rate case in the next 10 years.

NEC/SOS points out that BPA's assumption that there is no serial correlation between rate periods is not completely correct; that is, it is a simplifying assumption. Weiss, WP-02-E-NA-02, at 9. Recognizing Mr. Weiss's point, it can be observed that a 77 percent 10-year TPP can be obtained from two five-year rate periods if the "successful" sequences of years one to five have an 88 percent probability of success in years 6 to 10, even if the "unsuccessful" sequences of years one to five have a 0 percent probability of success in years 6 to 10. That is, with the incorporation of the serial correlation Mr. Weiss points out, it is possible to obtain a 77 percent 10-year TPP even if the second five-year rate period has a 77 percent TPP. Therefore, it would not be necessary for BPA to raise rates in 2006 in order to achieve an 88 percent TPP.

<u>Decision</u>

Since there is no 10-year 77 percent TPP standard, BPA is not obliged to demonstrate that it is met.

<u>Issue 2</u>

Whether Principle No. 4 requires that BPA demonstrate quantitatively that it can achieve an 88 percent TPP for the post-2006 rate period.

Parties' Position

NEC/SOS state that BPA must produce credible evidence that it will be able to establish rates sufficient to meet the 88 percent TPP standard for the second rate period. NEC/SOS Brief, WP-02-B-NA/SA-01, at 13.

OPUC argues that "[t]he statutory standard of "substantial evidence" has not been met, . . . and tends to undermine BPA's positions that Fish Funding Principle No. 4 is met." OPUC Brief, WP-02-B-OP-01, at 4. OPUC contends that in refusing to be tied to a quantitative demonstration, BPA has unnecessarily rejected the merit of any quantitative analysis in determining whether Principle No. 4 is met because there is no perfect analysis. OPUC Ex. Brief, WP-02-R-OP-01, at 5.

The Shoshone-Bannock Tribes support and join by reference the positions and suggested remedies of CRITFC/Yakama related to deficiencies in BPA's proposal with meeting TPP. Shoshone-Bannock Brief, WP-02-B-SB-01, at 9.

BPA's Position

Principle No. 4 requires that BPA design rates and contracts which will position BPA to achieve similarly high TPP for the post-2006 period by building financial reserve levels and through other mechanisms. "Principle No. 4 does not say that BPA will take actions now that result in an 88 percent TPP for the post-FY 2006 period calculated as of today or calculated as of FY 2006, but rather that BPA will *position* itself (now) to be able to achieve *similarly high* TPPs post-2006 period [sic]." DeWolf *et al.*, WP-02-E-BPA-39, at 37 (emphasis in original).

Principle No. 4 only calls for positioning to achieve a "similarly high" TPP, that is, 80 percent to 88 percent for the post-2006 period, not 88 percent. Volume 1, Revenue Requirement Study Documentation, WP-02-E-BPA-02A, at 355.

Evaluation of Positions

Principles No. 3 and No. 4 require that BPA position itself to achieve a similarly high (*i.e.*, 80 to 88 percent) TPP post-2006. The Principles are silent on the issue of the manner of demonstration. BPA has identified analytical obstacles that make impossible an analysis of post-2006 TPP with the rigor required by TPP analysis. *See* BPA's position in Issue 3, *infra*. BPA has determined, therefore, that the question of satisfaction of Principle No. 4 must be settled judgmentally, with quantification serving a supporting role. DeWolf *et al*., WP-02-E-BPA-39, at 37. OPUC argues that BPA's reliance on its "judgment," rendered largely on subjective and secret factors, to meet Fish Principle No. 4, in the face of countervailing quantitative evidence, is arbitrary and capricious. OPUC Ex. Brief, WP-02-R-OP-01, at 5. However, BPA has provided extensive discussion explaining its judgmental analysis, as well as two informal quantitative analyses, which BPA used to conclude that it is meeting Principle No. 4. *See* Issue 6, *infra*. BPA has also provided extensive discussion explaining why the quantitative analysis OPUC refers to is not convincing. *See* Issues 3, 4, and 5, *infra*.

There are several features of BPA's 2002 rates that contribute to BPA's confidence that it is positioning itself reasonably well to achieve a high TPP in the post-2006 years. *See* DeWolf *et al*., WP-02-E-BPA-39, at Attachment 4. They include the facts that BPA can set rates again in 2007, and can raise the rates substantially if necessary, as it has in the past; that any Slice customers will be taking on many risks that BPA has previously borne, and would be committing themselves to 10-year contracts; and that BPA is offering three-year contracts, as well as five-year contracts, giving BPA the opportunity to adjust rates in 2005, if necessary. *Id.* The expected values of BPA's annual financial reserves are projected in the 2002 rate case to increase quite substantially, though there is very large uncertainty in these projections. *Id.* This planned increase is on top of a healthy level of starting reserves, and BPA has designed a CRAC that could raise hundreds of millions of dollars of additional revenues if needed. *See* Response to NA-BPA:004, *Id*., for a more complete list. *See also* DeWolf *et al.*, WP-02-E-BPA-13, Section 4; Volume 1, Chapter 12, Revenue Requirement Study Documentation, WP-02-E-BPA-02A.

The wording of Principle No. 4 (*e.g.*, "position itself" and "similarly high Treasury payment probability") is essentially qualitative, and does not suggest that the drafters of the Principles had a quantitative definition in mind.

<u>Decision</u>

Satisfaction of Principle No. 4 does not require a <u>quantitative demonstration</u> proving that BPA will be able to achieve a post-2006 TPP of 88 percent, only a <u>showing</u> that BPA is positioning itself well at this time to be able to achieve a post-2006 TPP that is similar in security to the 80-88 percent TPP pledged in the Principles.

<u>Issue 3</u>

Whether BPA should have assessed the post-2006 TPP, and whether its lack of such assessment is a serious flaw in its rate proposal.

<u>Parties' Positions</u>

UCUT, CRITFC/Yakama, and NEC/SOS contend BPA must do, and has not done, a detailed analysis for the 2007-2011 period. UCUT Brief, WP-02-B-UC-01, at 20-21; CRITFC/Yakama Brief, WP-02-B-CR/YA-02, at 46; NEC/SOS Brief, WP-02-B-NA-01, at 23-24.

CRITFC/Yakama argue that they have provided analysis that the projected average ending reserve in BPA's initial proposal is too low to meet Principle No. 4. Sheets *et al*., WP-02-E-CR/YA-05, at 7. "BPA could have used Standsim to measure ability to meet Principle No. 4." Sheets, WP-02-E-CR/YA-01, at 3-4. NEC/SOS incorporates by reference the OPUC and CRITFC/Yakama briefs. NEC/SOS Brief, WP-02-B-NA/SA-01, at 36. NEC/SOS also assert that BPA "admits it has not employed a reasoned analysis," WP-02-B-NA/SA-01, at 14; in concluding that Principle No. 4 is being satisfied. CRITFC/Yakama claim that "Bonneville has asserted that it has met Principle No. 4 without any analysis." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 44. NEC/SOS submitted a quantitative analysis of its own that purports to show that BPA has not positioned itself to meet the 88 percent TPP goal for the post-2006 period. OPUC also uses the NEC/SOS analysis, terming it "unrebutted," to claim that quantitative analysis of the post-2006 TPP is, in fact, possible. OPUC Brief, WP-02-B-OP-01, at 3. CRITFC/Yakama assert that analyses performed by other parties indicate that quantitative analysis of post-2006 TPP is possible. CRITFC/Yakama Brief, WP-02-CR/YA-01, at 46. These three parties go on to argue that BPA's omission of a quantitative analysis of post-2006 TPP is a grave error.

UCUT claims BPA has not shown how its 2002 rates will meet Principle No. 4. UCUT Brief, WP-02-B-UC-01, at 20. UCUT argues that BPA should do detailed analysis for the 2007-2011 rate period and incorporate conservative outcomes of that analysis into this rate period's assumptions. *Id*. Or, UCUT claims, corresponding and more conservative risk mitigation measures should be incorporated into the rates. *Id*.

The Shoshone-Bannock Tribes support and join by reference the positions and suggested remedies of CRITFC/Yakama related to deficiencies in BPA's proposal with meeting TPP and adequately addressing the risks after 2006. Shoshone-Bannock Brief, WP-02-B-SB-01, at 9.

<u>BPA's Position</u>

Analysis at this time of the post-2006 TPP is not possible with the rigor that TPP analyses require. As stated in testimony:

> The technical problems associated with modeling and quantitative analysis of BPA's power business post-2006 are greater than implied by the Parties. A non-exhaustive list of such challenges is given here. The simplest of these difficulties have to do with the data:
>
> - The risk distributions from Risk Analysis Model (RiskMod) that represent operating risks are not available for the post-2006 period. The operational constraints for the 13 Fish and Wildlife Alternatives have not been analyzed, and are not available for use by RiskMod. The forecasts of gas and electricity prices that far in the future are far more uncertain than the forecasts for the FY 2002-2006 period.
>
> - BPA's Fish and Wildlife costs themselves for that period are far less certain. By FY 2007, it is possible that uncertainty over these costs will have been resolved; for example, by adoption of a regional plan or by Congressional action, or by spontaneous recovery of the fish stocks due to changes in ocean conditions. The range of future Fish and Wildlife costs may also have increased by FY 2007. Agreements about funding plans quite different from those under discussion today may have been reached. But at this time (December 1999), the post 2006 Fish and Wildlife costs would have to be considered to be highly uncertain, more uncertain than the FY 2002-2006 Fish and Wildlife costs are today.
>
> - BPA program costs have not been projected out that far with the rigor of those for the FY 2002 through 2006 period. The projections are developed consistently among the

programs and are sufficient for the 7(b)2 rate test purposes, where the significance is the cost categories that are excluded from the program case to produce the 7(b)(2) case.

- Other uncertainties are yet more complex. Some of the major structural uncertainties are:
  - National and state electricity industry restructuring plans--what will have happened by then?
  - Technological change--will generating supplies and loads be substantially the same, or will major changes have taken place on one or both sides of the supply and demand equation?
  - Congressional and FERC directions for BPA--what changes in BPA's responsibilities might be made by then?
  - How will financial markets have changed the ways that financial risks can be managed?

DeWolf *et al.*, WP-02-E-BPA-39, at 35-37.

The assessment of the TPP is the last step in the process of determining qualitative and quantitative assumptions in the analysis of proposed rates (*see*, *generally*, Volume 1, Chapter 12, Revenue Requirement Study Documentation, WP-02-FS-BPA-02A; Lovell *et al.*, WP-02-E-BPA-14; Conger *et al*., WP-02-E-BPA-15). In one sense the whole of BPA's rate case a description of the input assumptions and numbers for the TPP calculations. This set of inputs has been completed for the 2002-2006 period, but not for the post-2006 period.

BPA does not consider NEC/SOS's "analysis" unrebutted. BPA's rebuttal testimony addressed why BPA believes its rates do meet Principle No. 4, and why a rigorous quantitative analysis is not possible. DeWolf *et al*., WP-02-E-BPA-39, at 34-35. A rebuttal of the *possibility* that NEC/SOS's analysis might be meaningful in the current context is surely a stronger rebuttal than one that merely finds flaws with the details of the analysis.

The question is whether BPA is positioning itself appropriately now so that it will be able to take actions in the future resulting in similarly high TPPs after FY 2006. *Id*. at 37. In the face of the massive uncertainty facing BPA over the next seven years (12 years if we assume a five-year rate period starting in FY 2007), to define "well-positioned" so accurately as to permit meaningful statistical assessments would be impossible. *Id*. This uncertainty ensures that any analysis will contain so many assumptions as to be an essentially judgmental analysis. *Id*.

<u>Evaluation of Positions</u>

NEC/SOS acknowledged that its analysis was not consistent with BPA's models. Weiss, WP-02-E-NA-01, at 12. BPA presented substantial evidence that the post-2006 TPP cannot be assessed with enough rigor to make the results meaningfully comparable to the series of TPP analyses BPA provided in the initial proposal and previous rate cases. DeWolf *et al.,* WP-02-E-BPA-39, at 35. CRITFC/Yakama have argued that BPA is asserting it is meeting

Principle No. 4 but has not analyzed it. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 19. This is an incorrect characterization. BPA stated it is not relying primarily on quantitative analyses. Two analyses were used informally, and in addition BPA relied on judgmental analysis. DeWolf *et al.*, WP-02-E-BPA-39, at 37. CRITFC/Yakama also contend that failing to conduct quantitative analysis is arbitrary and capricious. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 19. They state "[t]he only logical explanation for Bonneville's failure to analyze this issue is that the problem will fall during the watch of another Administrator." *Id*. at 20. BPA strongly objects to this characterization. BPA has argued that TPP calculations for years so far in the future, with such a large number of assumptions necessary, are neither comparable to the calculations of 2002-2006 TPP presented in this rate proposal nor meaningful in their own right. *See* Issues 4 and 5, *infra*. BPA has a very robust risk mitigation package, and a higher TPP goal than ever before, and projects a high expected value of ending reserves, which positions BPA well for the subsequent rate period. *See* ROD chapter 7, *infra*. BPA's proposal is reasoned and reasonable, and meets Principle No. 4. *See* Issue 6, *infra*.

NEC/SOS concludes that this analysis should be done, because it has concluded that BPA's 10-Year Financial Plan requires a 10-year 77 percent TPP. This is not the case. *See* Issue 1, *supra*.

BPA mentions the importance of assumptions in determining the outcome of any analysis of post-2006 TPP. The record contains many examples of assumptions that would have to be made:

- The portion of the regional fish and wildlife plan that BPA would be required to fund. UCUT Brief, WP-20-B-UC-01, at 18-19.

- Whether BPA would be required to continue servicing debt on projects that no longer serve a power purpose in the event some dams are breached. DeWolf *et al.*, WP-02-E-BPA-39, at 30.

- How much uncertainty there will be about post-2006 fish and wildlife costs--the range may have broadened or shrunk, and may have increased or decreased in average cost. DeWolf *et al.*, WP-02-E-BPA-39, at 36. There is currently no clear scientific consensus on how to save the salmon (DeWolf *et al.*, WP-02-E-BPA-39, at 28), but the science may be more conclusive five years hence.

- What BPA's program costs will be after 2006. DeWolf *et al.*, WP-02-E-BPA-39, at 36.

- What the range of uncertainty about post-2006 market prices will be--the uncertainty *now* about post-2006 market prices is greater than the uncertainty *now* about market prices for 2002-2006. DeWolf *et al.*, WP-02-E-BPA-39, at 36.

- What additional financial risk management tools will be available to BPA to use in reaching its TPP goal. DeWolf *et al.*, WP-02-E-BPA-39, at 37.

- How national and state electricity industry restructuring plans will have affected the make-up of BPA's customer groups or the mechanisms through which BPA sells power to its customers. DeWolf *et al.*, WP-02-E-BPA-39, at 36.

- What the impacts will be of ocean conditions on the vitality of the threatened and endangered stocks. DeWolf *et al.*, WP-02-E-BPA-39, at 36.

- Whether BPA will selling power at cost-based rates or market rates. Saven, WP-02-E-NI-01, at 8.

The fact that the post-2006 period is so much more distant than is the 2002-2006 period means that many assumptions regarding issues of the sort just listed that are not only reasonable to make but unreasonable *not* to make for the nearer period are not nearly as safe to rely on for the post-2006 period. Any quantitative analysis will be strongly influenced or even determined by the assumptions on which it is based. Thus, any quantitative analysis of the post-2006 TPP will be an essentially judgmental analysis. DeWolf *et al.*, WP-02-E-BPA-39, at 37.

Decision

Any quantitative assessment of post-2006 TPP would be essentially judgmental; therefore, BPA is not obliged to perform such an assessment, nor is the lack of such an assessment a flaw in BPA's rate proposal.

Issue 4

Whether NEC/SOS's analysis of BPA's post-2006 rates and TPP should be treated as a minimum criterion for Principle No. 4.

Parties' Position

NEC/SOS asserts that BPA's claim that there are so many uncertainties as to make an analysis not meaningful is not a reason for ignoring NEC/SOS's analysis, but instead a strong argument for treating NEC/SOS's analysis as a *minimum* standard that must be met. NEC/SOS Brief, WP-02-B-NA/SA-01, at 22.

In their brief on exceptions, NEC/SOS argue that BPA reveals its lack of understanding of statistical methods when it asserts that an analysis which contains massive uncertainties cannot possibly be relied on for quantitative conclusions. NEC/SOS Ex. Brief, WP-02-R-NEC/SOS-01, at 7-8. NEC/SOS contend that statistics is the discipline most suited for dealing with uncertainties, and claiming that a set of data contains many uncertainties--even perhaps more than was originally assumed--does not always invalidate that study's conclusions. *Id*.

BPA's Position

The idea of treating the NEC/SOS analysis as a minimum standard was introduced in the NEC/SOS initial brief. NEC/SOS has misinterpreted both BPA's TPP policy (*see* Issue 1, *supra*) and Principle No. 4 (*see* Issue 2, *supra*), neither of which requires demonstration of an 88 percent TPP in the post-2006 period.

"In the face of the massive uncertainty facing BPA over the next seven years (12 years if we assume a five-year rate period starting in FY 2007) to define 'well-positioned' so accurately as to permit meaningful statistical assessments would be impossible. This uncertainty ensures that any analysis will contain so many assumptions as to be an essentially judgmental analysis." DeWolf *et al.*, WP-02-E-BPA-39, at 37.

<u>Evaluation of Positions</u>

The NEC/SOS analysis is not readily comparable to BPA's TPP analyses. *See* Issue 5, *infra*. NEC/SOS has not demonstrated that when analysis matching BPA's rate case standards cannot be performed, an analysis with "other assumptions and simplifications," Weiss, WP-02-E-NA-01, at 12; ought to be adopted as a "minimum," and be relied on to raise rates.

The uncertainties, *i.e.*, market price and reserve levels, that NEC/SOS cite make it difficult to be confident of any quantitative conclusions, even those of a "minimum" level. NEC/SOS claim that assuming more uncertainty in their analysis than was initially used does not invalidate the conclusion but instead strengthens it, and that statistics is the discipline most suited for dealing with uncertainty. NEC/SOS Ex. Brief, WP-02-R-NEC/SOS-01, at 7-8. This may be true when the uncertainty is of a statistical nature, such as the uncertainty over the supply of runoff available to drive hydropower generation, for which there is an extensive statistical history. However, the uncertainties cited by BPA as factors making statistical analysis of Principle No. 4 virtually meaningless are not of this nature. In Issue 3, *supra*, there are many assumptions listed that reflect political uncertainty:

- The portion of the regional fish and wildlife plan that BPA would be required to fund. UCUT Brief, WP-20-B-UC-01, at 18-19.

- Whether BPA would be required to continue servicing debt on projects that no longer serve a power purpose in the event some dams are breached. DeWolf *et al.*, WP-02-E-BPA-39, at 30.

- How national and state electricity industry restructuring plans will have affected the make-up of BPA's customer groups or the mechanisms through which BPA sells power to its customers. DeWolf *et al.*, WP-02-E-BPA-39, at 36.

- Whether BPA will selling power at cost-based rates or market rates. Saven, WP-02-E-NI-01, at 8.

There are assumptions listed in Issue 3, *supra*, that reflect uncertainty over the speed at which human knowledge or financial creativity will progress:

- How much uncertainty there will be about post-2006 fish and wildlife costs--the range may have broadened or shrunk, and may have increased or decreased in average cost.

DeWolf *et al.*, WP-02-E-BPA-39, at 36. There is currently no clear scientific consensus on how to save the salmon, DeWolf *et al.*, WP-02-E-BPA-39, at 28, but the science may be more conclusive five years hence.

- What additional financial risk management tools will be available to BPA to use in reaching its TPP goal. DeWolf *et al.*, WP-02-E-BPA-39, at 37.

The assertion by NEC/SOS that *statistics* ought to be used to assess uncertainty over the future actions of political bodies or uncertainty over the pace of scientific progress and financial engineering progress vastly overstates the power of statistics.

<u>Decision</u>

NEC/SOS's analysis of BPA's post-2006 rates and TPP need not be treated as a minimum criterion for Principle No. 4. The analysis contains so many assumptions that it cannot be persuasive.

<u>Issue 5</u>

Whether either NEC/SOS's analysis or CRITFC/Yakama's analysis demonstrates that BPA has not met Principle No. 4.

<u>Parties' Positions</u>

NEC/SOS, CRITFC/Yakama and OPUC contend that there is analysis that indicates Principle No. 4 is not met with BPA's proposal.

CRITFC/Yakama argue that they have provided analysis, using Strandsim, that demonstrates that the projected average ending reserve in BPA's initial proposal is too low to meet Principle No. 4. Sheets, WP-02-E-CR/YA-05, at 7. On the other hand, NRU states that the CRITFC/Yakama testimony presents an incomplete description of the NWPPC report on BPA costs and revenues. NRU Brief, WP-02-B-NI-01, at 13-14. CRITFC/Yakama used a NWPPC report entitled "Analysis of the BPA's Potential Future Costs and Revenues" and the Council's "Strandsim" model to justify CRITFC/Yakama argument that BPA should establish a $1.6 billion ending reserve target. CRITFC/Yakama's argument fails to acknowledge the other risk mitigation tools the report references (which BPA has, in effect, adopted), or the higher reserves in BPA's proposal compared to those in the NWPPC's study. "His [CRITFC/Yakama's] conclusions go well beyond any that may be fairly drawn from that study. His recommendations should be rejected." NRU Brief, WP-0-B-NI-01, at 13-14.

CRITFC/Yakama also argue that NEC/SOS's analysis shows that BPA's probability that it can maintain rates after 2006 that are less than market rates is less than 88 percent. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 45.

NEC/SOS state that "[g]iven the variance in the market price forecast and ending reserve levels, BPA's ability to raise rates high enough to meet its expected costs is well below 88 percent in the second rate period." NEC/SOS Brief, WP-02-B-NA/SA-01, at 24. "NWEC's analysis, in brief, calculated how high BPA's rates would have to be raised after 2006 given different ending (2006) reserve levels. Using only data provided by BPA, it then calculated the probability of those rates being under the market forecast, given the variance of that market forecast and the variance of the ending reserve level. The result was that probability was substantially lower than the 88 percent level demanded by the 1993 policy standard (and Principle No. 4)." *Id.* at 19. NEC/SOS also assert that "BPA must be able to reset rates post-2006 in order to meet its 1993 Policy and Principle No. 4. However, Bonneville cannot raise its rates above market without causing customers to leave its service. No party, including Bonneville, has demonstrated in any objective fashion that this condition can be met with a high probability. The only attempt was a single-point analysis by BPA which suggests that probability is only 50 percent, well below the standard required." *Id.* at 37.

OPUC incorporates NEC/SOS and CRITFC/Yakama's positions on compliance with Principle No. 4. OPUC Ex. Brief, WP-02-R-OP-01, at 3-4.

BPA's Position

It is impossible to do this analysis with the rigor that TPP analyses require. DeWolf *et al.*, WP-02-E-BPA-39, at 35. There are many severe technical and assumptive problems besetting any attempt to assess the post-2006 TPP. *See* list of problems under BPA Position for Issue 3, *supra*.

NEC/SOS have misinterpreted Principle No. 4, which does not require demonstration of an 88 percent TPP in the post-2006 period. *See* Issue 2, *supra.*

Evaluation of Positions

Principle No. 4 requires that BPA design rates and contracts which will position BPA to achieve similarly high TPP for the post-2006 period by building financial reserve levels and through other mechanisms. Volume 1, Revenue Requirement Study Documentation, WP-02-E-BPA-02A, at 355. "Principle No. 4 does not say that BPA will take actions now that result in an 88 percent TPP for the post-FY 2006 period calculated as of today or calculated as of FY 2006, but rather that BPA will *position* itself (now) to be able to achieve similarly high TPPs post-FY 2006 period [sic]." DeWolf *et al.*, WP-02-E-BPA-39, at 37. Principle No. 4 only calls for positioning to achieve a "similarly high" TPP, that is, 80 percent to 88 percent, for the post-2006 period, not 88 percent. *See* Issue 2, *supra*.

BPA has submitted a reasoned analysis of the issue of whether Principle No. 4 has been satisfied by BPA's 2002 rates. This reasoned analysis did not rely primarily on quantitative analysis, but two quantitative analyses were provided that support the satisfaction of Principle No. 4. The quantitative analysis of TPP is an especially rigorous analysis. Neither the rough approximation provided by BPA nor the NEC/SOS analysis match the rigor that BPA demands of TPP studies. BPA rebutted the NEC/SOS analysis in DeWolf *et al*., WP-02-E-BPA 39, at 34-39. In their brief on exceptions, NEC/SOS argue that they have submitted a meaningful assessment, "so evidently it is possible--it is only a question of whether it is correct. BPA must not be allowed to arbitrarily ignore the quantitative demonstration our expert witnesses presented which shows principle 4 is not being met by BPA's rates." NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 7. However, BPA has argued that the NEC/SOS analysis is not meaningful and does not demonstrate that BPA's proposal does not meet Principle No. 4. *See* Issue 4, *supra*. NEC/SOS also argue that their analysis is the test BPA put forward in its "Implementation of the Principles" table, Volume 1, Revenue Requirement Study Documentation, WP-02-E-BPA-02A, at 366. They contend that BPA is arbitrary and capricious by claiming it used this test to show it is implementing Principle No. 4, but then walking away from it when a more complete analysis shows that conclusion to be incorrect. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 8.

BPA has said that its two analyses, while rough and inexact, support, not prove, BPA's position, and that NEC/SOS's analysis does not disprove it. "In the face of the massive uncertainty facing BPA over the next seven years (12 years if we assume a five-year rate period starting in FY 2007) to define 'well-positioned' so accurately as to permit meaningful statistical assessments would be impossible. This uncertainty ensures that any analysis will contain so many assumptions as to be an essentially judgmental analysis." DeWolf *et al.*, WP-02-E-BPA-39, at 37.

CRITFC/Yakama claim their analysis demonstrates that BPA's projected ending reserve is too low to meet Principle No. 4. Sheets, WP-02-E-CR/YA-05, at 7. CRITFC/Yakama's analysis was done using a model developed by the NWPPC and assumptions developed by CRITFC/Yakama. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 21. However, as with the NEC/SOS analysis, the analysis used different modeling and assumptions than BPA used. Sheets, WP-02-E-CR/YA-01, at 4. "This makes the results very difficult to compare meaningfully, especially in light of the enormous uncertainty, . . . both between now and FY 2006 and during the post-FY 2006 period." DeWolf *et al.*, WP-02-E-BPA-39, at 39. CRITFC/Yakama also argue that NRU's criticism of their conclusion is inaccurate, and provides no new analysis that suggests that a reserve would not reduce potential rate increases in 2006 and improve repayment to the Treasury. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 21. "This fails the test of reasonableness." *Id.* BPA has not argued that higher reserves would not improve probability to the Treasury, but rather that BPA's rate proposal demonstrates a sufficiently high TPP. *See* ROD section 7.2, *infra*.

Analysis at this time of the post-2006 TPP is not possible with the rigor that TPP analyses require. "The technical problems associated with modeling and quantitative analysis of BPA's power business post-2006 are greater than implied by the Parties." DeWolf *et al.*, WP-02-E-BPA-39, at 37; *see also* Issue 3, *supra*.

There are several reasons why BPA is well positioned for the post-2006 period:

1. The range of fish and wildlife costs in the Principles is robust, in several ways.

    - Five of the 13 Alternatives include high-cost drawdown, even though it is unlikely that Congressional authorization and appropriations would occur in sufficient time for these costs to hit FY 2002-2006.

- Also, in implementing the Principles, BPA has assumed that Congress will appropriate capital funds consistent with the amounts and timing of investments projected in the 13 Alternatives. The level of appropriations required is nearly double the amount Congress has recently appropriated for Columbia River Fish Mitigation.

- Additionally, in developing the range, no test of scientific appropriateness has been applied to the activities included, and such a test might eliminate some of the activities.

DeWolf *et al*., WP-02-E-BPA-39, at 31.

2. BPA's studies assume BPA will pay all of the power-related costs contained in each of the alternatives. DeWolf *et al.*, WP-02-E-BPA-39, at 30. With respect to the dam breaching alternatives, BPA has included all of the power-related costs for the breach investment, plus assumed that BPA will repay the entire original cost of the dam that is still owed. *Id.* However, following breach, power production may no longer be a project purpose for the breached dams. *Id.* Should Congress authorize dam breaching, it will necessarily look at who should pay both the dam's original investment costs and the costs for breaching. *Id.* With no power generation purpose, it is uncertain whether BPA will remain responsible for the same scope of project costs. *Id.*

3. BPA may not be responsible for all other costs contained in the 13 Alternatives. Currently the region is working to develop a unified regional plan for fish and wildlife. DeWolf *et al.*, WP-02-E-BPA-39, at 31. An element of this plan will include determining what BPA will be responsible for, as well as the responsibilities for the other Federal agencies, states, and local governmental bodies. *Id.* It is not a certainty that BPA will be charged for 100 percent of the costs, because the plan has not been completed or approved, and Congressional action has not been taken. *Id.*

CRITFC/Yakama contend that in the above discussion, BPA appears to be arguing that there are a number of reasons why the more expensive alternatives will not happen, and that this is contrary to BPA's arguments elsewhere that it does not know which alternative will be implemented. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 19. NEC/SOS state that "BPA argues that it does not really think all alternatives are equally likely, that all costs are not likely to fall on BPA, and that "no test of scientific appropriateness has been applied to the activities" to assert that its financial fortunes will be better than modeled by NEC. NEC/SOS Ex. Brief, WP-02-R-NEC/SOS-01, at 13. NEC/SOS claim that it is disingenuous and capricious, however, for BPA to make such arguments. *Id*. NEC/SOS claim that in other contexts, BPA argues strongly that other parties' attempts to "second guess" the alternatives' probability of being implemented and costs are not appropriate. *Id*. at 13-14. CRITFC/Yakama and NEC/SOS appear to have misunderstood BPA's statements. BPA certainly does not know which alternative will be implemented, is including the full range of Alternatives, and is modeling the assumption that each of the 13 Alternatives is equally likely to occur. BPA recognizes that the more expensive alternatives could happen. CRITFC/Yakama and NEC/SOS have argued strenuously that they will. The discussion of why BPA considers its range robust is intended to indicate that there are also some reasons why they may not, and therefore BPA's proposal takes a balanced approach, considering the wide range of possibilities and uncertainties.

CRITFC/Yakama also contend that BPA appears to believe that some of the environmental costs will be paid for from Federal appropriations, and that it is not appropriate to assume changes in Federal law that would require Congress to provide funding for Bonneville when its rates have been substantially below market rates for the last 60 years. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA, at 20-21. They argue that such an assumption would be arbitrary and capricious. *Id.* Again, CRITFC/Yakama appear to have misunderstood BPA's statements. First, fish and wildlife capital costs of the COE and Reclamation, and O&M costs of USFWS are already funded by Federal appropriations. DeWolf *et al.*, WP-02-E-BPA-13, at 13. This would not be a change from current statute or practice. BPA's obligation for these investments is to repay Treasury for funding that Congress provided earlier through the annual appropriations process, not provide the initial funding. Second, BPA's rate proposal does not assume that BPA would directly receive any appropriations, nor does BPA expect that it would get any Federal appropriations for fish and wildlife costs. BPA's point is that this proposal assumes BPA would fully repay the currently applicable power portion of both the existing debt and the capital costs of breaching dams. Since the power portion of any dam would likely change with breaching, it is possible that Congress would reapportion the power purpose, or otherwise not require BPA to repay appropriations already spent on dam breaching. So though BPA recognizes the possibility that it may not retain these obligations, BPA's consideration of whether its rates do provide sufficiently for fish funding makes a conservative assumption--that all of the costs of a regional fish plan will be assigned to the FCRPS and that BPA will be granted no relief from these or other costs by Congress.

Part of the regional plan design will be the determination of what part of the funding will be BPA's responsibility. UCUT Brief, WP-20-B-UC-01, at 18-19. There is no evidence that the NEC/SOS analysis considered this.

NEC/SOS presented evidence that the NEC/SOS analysis is not readily comparable to BPA's TPP analyses. Weiss, WP-02-E-NA-01, at 10-12. NEC/SOS has not demonstrated that when analysis matching BPA's rate case standards cannot be performed, an analysis with "other assumptions and simplifications," *id*. at 12, ought to be relied on to raise rates.

As BPA has pointed out, quantitative analyses of post-2006 TPP require the making of a great many assumptions. *See* Issue 3, *supra*. The arguments by the parties that BPA will not be able to achieve an 80 to 88 percent post-2006 TPP require assuming that BPA's post-2006 fish and wildlife costs will be very high, which in turn requires assuming that the annual levels of appropriations that BPA would have to repay would vastly exceed current or historical levels approved by Congress. Congress has not authorized appropriations even as high as planned in the MOA for the current rate period. Lovell *et al*., WP-02-E-BPA-40, at 22. An analysis that makes assumptions about future decisions of Congress could just as well assume that Congress would not only approve record levels of appropriations but would also allow BPA significant flexibilities in its repayment planning in order to ensure that such repayment does not cause economic disruptions in the PNW, thereby producing a result indicating a lack of financial problems for BPA. This demonstrates clearly that the result of any such analysis depends critically on political assumptions and is therefore essentially judgmental.

Decision

Neither NEC/SOS's nor CRITFC/Yakama's analysis demonstrates that BPA has not met Principle No. 4.

Issue 6

Whether BPA has met Principle No. 4.

Parties' Positions

NEC/SOS, CRITFC/Yakama, UCUT, and OPUC all claim that BPA has not demonstrated that its proposal meets Principle No. 4. OPUC states that NEC/SOS presented unrebutted testimony that quantitative analysis is possible and that even rudimentary analysis demonstrates that BPA has not met Principle No. 4. OPUC Brief, WP-02-B-OP-01, at 3. "BPA's proposed CRAC revenues of $125 million to $175 million per year will be insufficient to meet Principle No. 4 if BPA experiences several successive bad water years or incurs high costs." *Id*. at 9-10.

OPUC incorporates the NEC/SOS and CRITFC/Yakama positions on compliance with Principle No. 4. OPUC Ex. Brief, WP-02-ROP-01, at 3-4.

UCUT asserts that "if fish and wildlife costs are at the high end of the assumptions made by BPA in this rate case, it may not be able to fund fish and wildlife in the next rate period and make treasury payments without exceeding the market price of power." UCUT Brief, WP-02-B-UC-02, at 21. With an 88 percent TPP, there is a 12 percent chance that there will be no reserves and a failure to meet Treasury payment. *Id*.

The DSIs state that nothing in the record supports a judgment that Principle No. 4 would be undermined by adopting an 80 percent TPP. DSI Brief, WP-02-B-DS-01, at 50.

The Shoshone-Bannock Tribes support and join by reference the positions and suggested remedies of CRITFC/Yakama related to deficiencies in BPA's proposal with meeting TPP and adequately addressing the risks after 2006. Shoshone-Bannock Brief, WP-02-B-SH-01, at 9.

BPA's Position

BPA has met Principle No. 4.

BPA interprets Principle No. 4 to mean that BPA must position itself reasonably well for, or position itself to have a reasonable expectation of, achieving a similarly high TPP post-2006. BPA asserts that the 2002 rates position BPA's power function reasonably well to be able to obtain a "similarly high" TPP for the post-2006 period through such mechanisms as potential rate increases, a planned build-up of reserves, potential rate adjustment mechanisms, and other actions that can be taken between now and 2007. DeWolf *et al*., WP-02-E-BPA-39, Attachment 4, at 1. Meeting Principle No. 4 does not require that BPA demonstrate a certainty of 88 percent TPP for FY 2007-2011, when calculated in FY 2000.

BPA considers that Principle No. 4 is either satisfied or violated as of the time of the release of the 2002 power rate case ROD. At the time of that release, BPA either has or has not positioned itself reasonably well to achieve a similarly high TPP for the post-2006 period. Subsequent good or bad luck (*i.e.*, high or low ending FY 2006 reserves) will not change that. Cross-Examination Exhibit, WP-02-E-NA/OP/CR/YA-11.

In addition, there are reasons why future fish and wildlife costs may not necessarily be entirely BPA's responsibility. Current debt repayment obligations for dams are not certain to continue if the breaching of those dams is authorized. DeWolf *et al*., WP-02-E-BPA-39, at 31. The Direct Program budget from CBFWA has not been approved by the NWPPC yet.

In its brief on exceptions, OPUC argues that BPA has interpreted Principle No. 4 as if compliance with the principle is entirely governed by BPA's discretion, and OPUC takes exception to BPA's determination that it has met Principle No. 4. OPUC Ex. Brief, WP-02-R-OP-01, at 6. However, BPA believes its proposal meets Principle No. 4 though it does not rely primarily on quantitative analysis.

If BPA misses a payment to Treasury, it does not mean that funding for fish and wildlife programs or measures is being reduced. DeWolf *et al*., WP-02-E-BPA-13, at 14. Rather, it means that repayment or reimbursement is delayed for funding that already has been expended. *Id*. Fish and wildlife costs that do not take the form of payments to Treasury are higher in the priority of payments. *Id*. Inasmuch as payments to Treasury represent the lowest priority of payments, these higher priority costs are virtually guaranteed to be recovered, which is to say, the availability of cash to fund these costs is certain. *Id*. at 14-15.

<u>Evaluation of Positions</u>

The quantitative criteria cited by the parties have been rejected. *See* Issues 1-5, *supra*. BPA has submitted a reasoned analysis of the issue of whether Principle No. 4 has been satisfied by BPA's 2002 power rates. This reasoned analysis did not rely primarily on quantitative analysis, but two quantitative analyses were provided that support for the satisfaction of Principle No. 4. DeWolf *et al*., WP-02-E-BPA-39, at 35. The quantitative analysis of TPP is an especially rigorous analysis. Neither the rough approximation provided by BPA, nor the NEC/SOS or CRITFC/Yakama analyses match the rigor that BPA demands of TPP studies. BPA rebutted the NEC/SOS analysis in DeWolf *et al*., WP-E-02-BPA-39, at 34-39.

"BPA has not performed Strandsim analyses of this issue." DeWolf *et al*., WP-02-E-BPA-39, at 39. As CRITFC/Yakama's testimony admits, Strandsim is not one of the models used by BPA in its rate case. Sheets, WP-02-E-CR/YA-01, at 4. There are many differences in data, scope, and analytical assumptions. This makes the results very difficult to compare meaningfully, especially in light of the enormous uncertainty, described above, both between now and FY 2006 and during the post-FY 2006 period." DeWolf *et al.*, WP-E-02-BPA-39, at 39.

Current science is highly uncertain; other parties have testified that the costs BPA is using are excessive, not inadequate. In the face of this uncertainty, the Administrator must still finish a power rate case in time to sell the Federal power when the rates currently in effect expire at the end of FY 2001.

There are several features of BPA's 2002 power rates that contribute to BPA's confidence that it is positioning itself reasonably well to achieve a high TPP in the post-2006 years. *See* DeWolf *et al.*, WP-02-E-BPA-39, Attachment 4. They include the facts that BPA can set rates again in 2007, and can raise the rates substantially if necessary, as it has in the past; that any Slice customers will be taking on many risks that BPA has previously borne and would be committing themselves to 10-year contracts; and that BPA is offering three-year contracts, as well as five-year contracts, giving BPA the opportunity to adjust rates in 2005, if necessary. *Id.* The expected values of BPA's annual financial reserves are projected in the 2002 rate case to increase quite substantially, though there is very large uncertainty in these projections. *Id.* This planned increase is on top of a healthy level of starting reserves, and BPA has designed a CRAC that could raise hundreds of millions of dollars of additional revenue if needed. *See* Response to NA-BPA:004, *id.*, for a more complete list. *See also* DeWolf *et al.*, WP-02-E-BPA-13, section 4; Volume 1, Chapter 13, Revenue Requirement Study Documentation, WP-02-E-BPA-02A.

Parties have claimed that BPA's 2002 power rates do not meet Principle No. 4 because BPA does not demonstrate an 88 percent TPP for post-2006, but Principle No. 4 does not require this. *See* Issues 2 and 3, *supra*. Parties also have claimed that the NEC/SOS and CRITFC/Yakama analyses demonstrate that BPA's proposal does not meet Principle No. 4; however, the NEC/SOS analyses contain so many assumptions that they are not persuasive. *See* Issue 5, *supra*. BPA has provided reasoned analysis showing that its proposal meets Principle No. 4. *See* Issues 2-5, *supra* for arguments that demonstrate that BPA is meeting Principle No. 4.

Decision

BPA has met Principle No. 4.

5.5 Functionalization of BPA's Fiber Optic Communication Equipment

Issue

Whether BPA's investment in fiber optic communications equipment is appropriately assigned to the TBL.

Parties' Positions

The IOUs/Enron argued that BPA should not be allowed to assign the investment in fiber optic communications equipment to TBL, because TBL has the opportunity to minimize its costs and exposure to financial risk by negotiating an agreement with a private telecommunications company whereby BPA could allow its infrastructure to be used for a fiber optic network in exchange for access to a portion of the fiber optics cable. Hornby, WP-02-E-AC/GE/IP/MP/PL/PS/EN-06, at 6. In the alternative, they argued that BPA should be required to turn over the financial responsibility for the investment to date, and future investments, to the PBL. *Id.* at 6. The IOUs/Enron also contended that BPA has effectively entered the fiber optics market by making this massive investment and leasing the resulting excess fiber optic cable to third parties. *Id*. at 7. Therefore, if BPA wishes to participate in this competitive market, it should functionalize its fiber optic cable costs to the PBL, which operates in a competitive, wholesale power market. *Id*. at 7-8. Further, any marketing advantage resulting from BPA's leasing of fiber optic cable will inure to the PBL, not the TBL. *Id*. at 8; Hogan, WP-02-E-AC/GE/IP/MP/PL/PS/EN-07, at 6. The IOUs also assert that as a matter of law under sections 7(a) and 7(g) of the Northwest Power Act, BPA's investment in fiber optic equipment must be allocated to power rates. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 76.

PPC contended that "it is entirely appropriate for the costs associated with investment in fiber optics [to] be functionalized to TBL." Hansen *et al.*, WP-02-E-PP-09, at 24. They cite that "fiber optic communication spending to date has been appropriate and part of the normal TBL communications system upgrade process; that the incremental cost of dark fiber is minimal compared with the fixed cost of installation; that installation of additional dark fiber over and above current need is a sound business practice; and that the IOUs' concerns about risk to TBL and its transmission customers are unfounded." *Id.* WPAG also responded to the IOU proposal, arguing that "it runs directly contrary to cost causation principles. The fiber optic system was installed for the purpose of maintaining and improving reliable operation of the transmission system." Cross *et al*., WP-02-E-WA-02, at 10.

<u>BPA's Position</u>

BPA's communications equipment, including fiber optic cable, is used in the operation of the Federal Columbia River Transmission System (FCRTS). DeWolf *et al.*, WP-02-E-BPA-39, at 47. Functionalization should be based on use and cost causation. *Id.* at 48. The overall investments in fiber optic cable have been and are being made ultimately for transmission system usage. *Id.*

<u>Evaluation of Positions</u>

The IOUs/Enron contended that BPA's fiber optic investments are "at the risk of its TBL customers" and that "the private sector has demonstrated it can provide this type of service at significantly lower cost . . . " Hogan, WP-02-E-AC/GE/IP/MP/PL/PS/EN-07, at 5. In fact, the IOUs/Enron asserted that the appropriate cost to BPA's transmission customers for upgrading the communication system is zero, citing a 1992 proposal to BPA from a private telecommunications company that allegedly demonstrated that the TBL could have received fiber optic communications service at no cost in exchange for the use of transmission rights-of-way for installing fiber optic cable. *Id.* at 2-3. The IOUs/Enron also argued that there is the potential risk that "fiber optics are rendered obsolete or reduced in value by new communications technologies." Hornby, WP-02-E-AC/GE/IP/MP/PL/PS/EN-06, at 6-7. Therefore, ". . . if TBL has the opportunity to minimize its costs and exposure to financial risk by outsourcing a function or buying a resource, it should do so. The TBL has an opportunity to do just that with respect to fiber optic cable." *Id*. at 6. In general, the IOUs/Enron state, the Government should not invest in risky new technologies when private sector companies will accept the risk and can do the job at a lower cost. *Id.* at 7.

BPA disagrees with the IOUs/Enron assertion that BPA should be foreclosed from making a business decision to install fiber optic cable on its own transmission system for its own communications purposes just because there may be a private company somewhere who also deals in fiber optic cable installations (allegedly at a lower cost). The IOUs/Enron argued that a private company can do it at lower cost, but the only evidence they provided is an anecdotal discussion about a proposal submitted to BPA in 1992 by Touch America that BPA decided not to accept as proposed. Hogan, WP-02-E-AC/GE/IP/MP/PL/PS/EC-07, at 2-3. "In August 1994, BPA decided that it wanted to own the entire cable and lease a portion of the cable to Touch America. BPA replaced the Touch America proposal with a lease agreement." *Id.* at 4. The IOUs/Enron then stated that "[t]his was obviously a significant departure from what had been discussed previously" and alleged that this act "indicated BPA's decision to enter the dark fiber business for more than the use of its transmission customers." *Id.* However, there is no evidence in the record to substantiate this assertion. Coincidentally, this piece of testimony is sponsored by the general manager of operations with Touch America, a wholly owned telecommunications subsidiary of the Montana Power Company (MPC), one of the parties sponsoring this testimony. *Id.* at 1.

PPC argued that "the IOUs' concerns about risk to TBL and its transmission customers are unfounded." Hansen *et al.*, WP-02-E-PP-09, at 24. They asserted that, concerning transmission rates, customers "will have sufficient opportunity on the record to influence this classification process so as to ensure that revenues to cover TBL costs are allocated appropriately" in the Northwest Power Act's section 7(i) process and by the fact that BPA "has voluntarily submitted itself to FERC review of TBL rates, terms and conditions similar to standards applicable to other transmission owners." *Id.* at 28.

In the alternative, the IOUs/Enron argued that BPA should be required to turn over the financial responsibility for the investment to date, and future investments, to the PBL. Hornby, WP-02-E-AC/GE/IP/MP/PL/PS/EC-06, at 7. The IOUs/Enron contended that BPA has effectively entered the fiber optics market by making this massive investment and leasing the resulting excess fiber optic cable to third parties. *Id.* at 7. Therefore, if BPA wishes to participate in this competitive market, it should functionalize its fiber optic cable costs to the PBL, which operates in a competitive, wholesale power market. *Id*. at 7-8. Further, the IOUs/Enron state, any marketing advantage resulting from BPA's leasing of fiber optic cable will inure to the PBL, not the TBL. *Id.* at 8; Hogan, WP-02-E-AC/GE/IP/MP/PL/PS/EN-07, at 6.

BPA disagrees with the IOUs/Enron allegation that the costs of BPA's investment in fiber optics must be functionalized to power:

> BPA's communication equipment, including fiber optic cable, is used in the operation of the FCRTS. In previous rate cases, BPA functionalized between generation and transmission the investment in the Dittmer Control Center and supporting communications equipment needed to perform the resource dispatch and control operations. The portion needed for dispatch and control of the Federal resources were assigned to power. Now that transmission entities are required to provide ancillary services, which include dispatch and control, and the

> power function is required to take these services at the same rates charged to others, what previously had been the generation portion of these investments is now appropriately assigned entirely to the transmission function. In BPA's transmission rate case, these costs will be allocated to transmission or ancillary services. Should it be determined that the PBL is responsible for costs associated with any incidental uses of communications plant other than for transmission or ancillary services, [the functionalization of] those costs will be represented by a user charge from the TBL to the PBL. An assumption concerning such a charge is reflected in the inter-business line expenses in the generation revenue requirements. In the subsequent transmission rate case, we expect that incidental uses will be appropriately accounted for in the transmission revenue requirement.

DeWolf *et al.,* WP-02-E-BPA-39, at 47-48.

In addition, "[f]unctionalization should be based on use and cost causation. The overall investments have been and are being made ultimately for transmission system usage." *Id.* at 48.

The PPC agreed that the intent of BPA's fiber optic investment was for transmission. They stated that "BPA's fiber optic investment is communication for the support and reliability of its transmission system. Therefore, it is reasonable for BPA to functionalize equipment primarily for that purpose to the TBL." Hansen *et al.*, WP-02-E-PP-09, at 25. WPAG also agreed concerning the intent of these investments. They stated that the IOU/Enron "proposal to charge the entire cost of the fiber optic system to PBL runs directly contrary to cost causation principles. The fiber optic system was installed for the purpose of maintaining and improving reliable operation of the transmission system." Cross *et al.*, WP-02-E-WA-02, at 10. PPC further disagreed that PBL's customers are the intended recipients of the excess capacity. "The intended recipients . . . are private companies, non-profit entities and BPA's public agency customers. . . . [S]ome BPA utility customers . . . that place very little generation load on BPA . . . may potentially benefit from this service." Hansen *et al.,* WP-02-E-PP-09, at 26.

The IOUs argue that ". . . these huge expenditures [in fiber optic cable] should not be assigned to TBL because private sector companies in the fiber optic business have been willing to install fiber optic cable on BPA's transmission lines at no cost to BPA." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 74. "Because BPA's fiber optic capital costs could have been completely avoided, . . . they were not incurred for the transmission function and should not be functionalized to transmission and should not be collected in transmission rates." *Id.* at 76. The IOUs also argue that under section 7(a) of the Northwest Power Act, BPA's transmission rates must equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system. *Id.* They cite *U.S. Department of Energy-Bonneville Power Admin.*, 25 FERC ¶ 61,140, 61,375 (1983), for the proposition that BPA's power costs and transmission costs be separately accounted for and that "costs assigned to transmission are only transmission related costs . . ." *Id.* "Further, Section 7(g) of the Northwest Power Act requires that all costs not otherwise allocated by law shall be equitably allocated to power rates. Therefore, BPA's fiber optics capital costs, which cannot be allocated to transmission rates, must be allocated to power rates under Section 7(g) of the Northwest Power Act." *Id.*

The IOUs' argument fails because it is based on an incorrect premise that BPA's fiber optic capital costs have been incorrectly assigned to transmission. This fragile line of reasoning rests solely on the contention that, because BPA chose not to exchange access to certain transmission rights-of-way for some fiber optic communication service, there was an ulterior motive having nothing to do with upgrading BPA's transmission communication system. As stated above, "[f]unctionalization should be based on use and cost causation. The overall investments have been and are being made ultimately for transmission system usage." DeWolf *et al.,* WP-02-E-BPA-39, at 48.

In their brief on exceptions, the IOUs/Enron stated that "BPA misunderstands our position and fails to address the principal argument of the Northwest Investor-owned Utilities, that BPA's transmission customers should not bear the cost of investments that are not intended to benefit or to provide service to transmission customers." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 55. Unfortunately, this specific conclusion from their initial brief was inadvertently omitted from the discussion of the issue in the Draft ROD. They further stated in their brief on exceptions that "it is our position, supported by the testimony of Richard Hornby and Patrick Hogan, that BPA has not made a business decision merely to install fiber optic cable for its own communications purposes, but has made a business decision to enter the highly competitive and risky fiber optic telecommunications business, and the captive customers of TBL's monopoly transmission system should not bear the risk or expense of this new BPA business venture." *Id*. at 55-56.

The IOUs/Enron referred to the testimony of their witness to support their characterizations of BPA's motives pertaining to the installation of fiber optic cable. They contended that "Mr. Hornby's testimony demonstrates that BPA has invested a substantial amount of money in a fiber optic cable network that BPA does not currently need," *id*., at 56; a contention that manipulates the words of their witness to imply that the communications network itself is beyond BPA's needs rather than the full capacity of fiber optic cable being installed. Hornby, WP-02-E-AC/GE/IP/MP/PL/PS/EN-06, at 5. They further contended that the witness' testimony demonstrates that this network is above and beyond what BPA can be "reasonably be expected to use to meet its future transmission or generation-related needs." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 56. Unfortunately, Mr. Hornby's testimony makes no such demonstration or even pronouncement on this point. They further offer as support to their position that, "Mr. Hornby demonstrates that it is unrealistic and unreasonable for BPA to assume that it will be able to recall this leased capacity." *Id*. at 56-57. Mr. Hornby's testimony provides no such demonstration; he merely opines that BPA would be unable to recall the leased capacity once it was relied on by rural communities, but then immediately undercuts that conclusion by saying that rural communities do not "necessarily lack economically viable options from commercial providers." Hornby, WP-02-E-AC/GE/IP/MP/PL/PS/EN-06, at 5.

The IOUs/Enron further stated that "[u]ncontroverted evidence, in the form of Mr. Hogan's testimony, demonstrates that a specific, identified company was willing and able to pay for and install fiber optic cable to meet BPA's communications needs at no cost to BPA, in exchange for the use of BPA's rights-of-way. Instead, BPA spent $103 million since 1993 for equipment and services that BPA could have obtained for free." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 56. Mr. Hogan's testimony in no way addresses or substantiates whether this proposal, which was discussed earlier, was sufficient to meet BPA's needs and requirements concerning communications facilities. However, this proposal and Mr. Hornby's testimony give the IOUs/Enron the basis to state that since "the costs of fiber optic facilities were avoidable, and because the vast majority of expenditures was for facilities not currently used and that may never be used to provide transmission service, the associated costs cannot be assigned to TBL and must be functionalized to PBL, as a matter of law." *Id.* at 57. They contended that, in the Draft ROD, "BPA beats the drum of cost causation without addressing the central and undisputed factual tenet of the Northwest Investor-owned Utilities' argument that BPA's excessive expenditure for fiber optic communications equipment is not justified or "caused" by TBL's communication needs." *Id*. Such loose characterization of "undisputed factual tenet" concerning whether the expenditures truly are excessive or not justified by TBL's needs is a stretch of reasoning that is not, as discussed, definitively supported in the cases of the witnesses. In fact, the Hearing Officer recognized that "Mr. Hornby and Mr. Hogan have difficulty focusing on the issues in this case and stray in and out of their answers to areas that are not allowed under the FRN. . . . [T]he testimony overreaches by revisiting history and second-guessing BPA's policy decisions concerning fiber optic investment which are not at issue in this proceeding. Any discussion of cost functionalization appears as a "tack-on" item in an effort to save what would otherwise be inadmissible testimony." Order Granting In Part and Denying In Part Motions to Strike Testimony, WP-02-O-14, at 12.

BPA asserted, as earlier cited, that the installation of fiber optic cable was ultimately for transmission system usage and, as earlier cited, that position was supported by PPC and WPAG. Most importantly, the IOUs/Enron offer no evidence that BPA would not recover the cost associated with the excess capacity through the leases, which would be reflected as revenue credits in developing transmission rates, thus achieving the end state they argue for, that transmission rates not bear those costs. Without consideration of the revenue from the excess capacity leases, the IOUs/Enron contention that the "allocation of excess capacity fiber optic cable costs is not governed by the Transmission Act . . . or any provision of law other than Section 7(g) of the Northwest Power Act. Therefore, the bulk of BPA's investment in fiber optics cannot be allocated to transmission rates and must be allocated to power rates under Section 7(g) of the Northwest Power Act." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 59; is an incomplete view of the issue. This is also true for their argument that "FERC policy does not permit utilities to include in transmission rates the costs of facilities that are not caused by and are not used to provide transmission services. Costs of fiber optic cable that are intended to benefit customers of BPA's new telecommunications business, rather than TBL's transmission customers, and that are excess to TBL's real current and future needs are not used to provide transmission services and cannot be recovered through transmission rates." *Id.* at 58.

Decision

BPA's investment in fiber optic communications equipment is appropriately assigned to the TBL. In BPA's transmission rate case, communications equipment costs will be assigned to transmission or ancillary services. Should it be determined that the PBL is responsible for costs associated with any incidental uses of communications plant, the functionalization of those costs will be represented by a user charge from the TBL to the PBL.

5.6 Functionalization of the Costs of Energy Conservation and Renewable Resources

Issue

Whether BPA appropriately functionalized energy conservation and renewable resource costs entirely to the generation function.

Parties' Positions

WPAG argues that, because BPA's energy conservation and renewable resource programs provide certain benefits to the transmission system, BPA should functionalize a portion of the costs of these programs to transmission. Cross *et al.*, WP-02-E-WA-01, at 22-23. WPAG argues that BPA should assign a percentage of the conservation and renewable resource programs to transmission equal to the percentage that the TBL revenue requirement constitutes of BPA's total revenue requirement. *Id.* at 23; WPAG Brief, WP-02-B-WA-01, at 13.

Various parties rebutted WPAG's proposed functionalization. The IOUs state that WPAG's proposal did not comply with the treatment of conservation directed by the Northwest Power Act and that "renewables are power generating resources and should therefore be included in generation revenue requirements." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 72-73. The Joint DSIs contended that WPAG provided no basis of support for its proposal. Schoenbeck and Bliven, WP-02-E-DS/AL/VN-06, at 29. PP&L Montana LLC (PPLM) added that WPAG's proposal "reflects neither how costs were incurred nor how benefits from these programs accrue. It therefore violates the fundamental ratemaking principle that rates should reflect cost causation." PPLM Brief, WP-02-B-PM-01, at 12. PPLM further argues that "any reductions in transmission demand incidental to conservation or renewable programs are very location-specific," which WPAG did not consider. *Id.*

BPA's Position

BPA stated that this issue, with respect to conservation, was raised by WPAG and resolved in the 1993 rate case, wherein the decision was made "that section 7(g) of the Northwest Power Act requires conservation costs to be assigned to power rates and, while that did not preclude the costs from being functionalized to transmission, the transmission component would still need to be assigned to power rates." DeWolf *et al.*, WP-02-E-BPA-39, at 46. In addition, since transmission rates under FERC's open access provisions no longer create separate rates for wheeling and transmission of Federal power, there is less ability to functionalize conservation costs to transmission. *Id.* Further, renewable resources are clearly power-generating resources and, for ratemaking purposes, their costs should be included in the generation, not transmission, revenue requirements consistent with the ratemaking provisions of the Northwest Power Act. *Id.* at 47.

Evaluation of Positions

Under the Northwest Power Act, BPA can acquire energy conservation and renewable resources. 16 U.S.C. §839d. The Northwest Power Act defines the term "resource" as "electric power, including the actual or planned electric power capability of generating facilities, or actual or planned load reduction resulting from direct application of a renewable energy resource by a consumer, or from a conservation measure." 16 U.S.C. §839a(19). The costs of conservation and renewable resources are components of the generation revenue requirements. For ratemaking purposes, energy conservation costs are included in the conservation resource pool. The costs of renewable resources can be included in any of the resource pools depending on BPA's determination of the character of the resource.

WPAG contended that BPA's conservation and renewable energy programs benefit both generation and transmission systems by reducing the need for new transmission facilities. Cross *et al.*, WP-02-E-WA-01, at 22-23. Consequently, "BPA should assign a percentage of the conservation and renewable resource programs to transmission equal to the percentage that the TBL revenue requirement constitutes of BPA's total revenue requirement." *Id.* Otherwise, BPA's "proposed functionalization will result in the PBL customers being unfairly saddled with conservation and renewable resource costs which provide benefits to the TBL." WPAG Brief, WP-02-B-WA-01, at 13.

However, this issue, with respect to conservation, was raised by WPAG and resolved in the 1993 rate case, wherein the decision was made "that section 7(g) of the Northwest Power Act requires conservation costs to be assigned to power rates and, while that did not preclude the costs from being functionalized to transmission, the transmission component would still need to be assigned to power rates." DeWolf *et al.*, WP-02-E-BPA-39, at 46. The fact that Subscription products are primarily undelivered power further reduces the possibility of assigning conservation costs to transmission. *Id.* In addition, since transmission rates under FERC's open access provisions no longer create separate rates for wheeling and transmission of Federal power, there is less ability to functionalize conservation costs to transmission. *Id.* Further, renewable resources "are clearly power-generating resources and, for ratemaking purposes, their costs should be included in the generation, not transmission, revenue requirements consistent with the ratemaking provisions of the Northwest Power Act." *Id.* at 47.

WPAG responded to the 1993 rate case resolution of the issue, arguing that "the fact that an issue was addressed in a prior rate proceeding does not prohibit BPA from addressing the issue on its merits in a subsequent proceeding." WPAG Brief, WP-02-B-WA-01, at 13-14. WPAG also asserts that:

> Section 7(g) of the Regional Act deals with the allocation of costs not otherwise allocated under other provisions of the law. Section 7(g) does not speak to the functionalization of costs. The functionalization step normally occurs before the allocation step in the rate setting process. As a consequence, section 7(g) only deals with the allocation of costs that have been properly functionalized to the power function. Section 7(g) poses no impediment to the proper functionalization

> of conservation and renewable resources costs between TBL and PBL prior to allocation pursuant to section 7(g).

Id. at 14*.*

WPAG also offered the unsupported statement that "many costs that were previously allocated to power rates under section 7(g) have now been functionalized to transmission." *Id.* at 15.

BPA disagrees with WPAG 's assertion that the use of the term "allocation" in section 7(g) specifically refers to the step in utility ratemaking following functionalization and, thereby, only addresses those costs functionalized to generation. As stated in the 1993 ROD, BPA believes that the Northwest Power Act does not speak to functionalization. Section 7(g) of the Northwest Power Act requires that all of the costs of energy conservation, regardless of functionalization, must be allocated to power rates. 1993 ROD, WP-93-A-02, at 40.

The IOUs also addressed the ratemaking directives of the Northwest Power Act, arguing that WPAG's proposal "is inconsistent with the Northwest Power Act, which treats conservation as a resource. Moreover, renewable resources are power-generating resources and should therefore be included in generation, not transmission, revenue requirements." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 72-73. Others addressed the technical merits of WPAG's proposal. The Joint DSIs contended that WPAG "provided no basis to determine that its proposed allocation of costs between functions is reasonable. WPAG must present a basis for determining any savings in transmission costs due to conservation and renewables before any allocations could even be considered." Schoenbeck and Bliven, WP-02-E-DS/AL/VN-06, at 29. PPLM argued that "BPA's conservation and renewable resource programs are generally designed, evaluated, and developed to provide energy savings and, thereby, reduce or defer the need for additional generation resources and power purchases. Any reduction that such programs have caused in the need for investment in transmission facilities has been merely incidental to BPA's decision to acquire conservation and renewable resources." PPLM Brief, WP-02-B-PM-01, at 11-12. PPLM concluded from this that WPAG's proposal "violates the fundamental ratemaking principle that rates should reflect cost causation." *Id.* Moreover, any reductions in transmission demand incidental to conservation or renewable programs are very location-specific. This fact would necessitate that both calculation of the assignable percentages and determination of the transmission segment appropriate for assignment be made on a resource-by-resource basis. *Id.* at 12. PPLM concludes that "WPAG's proposal fails to address or even recognize this issue." *Id.*

WPAG has supported their proposed functionalization of renewable energy programs with the contention that new renewable resource technologies such as fuel cells "will allow generation to be placed close to load, thereby easing constraints on the transmission system" and that "solar photovoltaic generators . . . hold the promise of serving remote rural loads at a much lower cost than building transmission lines to serve those loads." Cross *et al.*, WP-02-E-WA-01, at 23. However, they fail to even link these technologies with BPA's renewable resources program, which consists primarily of funding for the development of geothermal and wind resources. Volume 1, Revenue Requirement Study Documentation, WP-02-E-BPA-02A, at 34-36.

WPAG concludes that "BPA should recognize the uncontroverted fact that conservation and renewable resources provide benefits to both the power and transmission systems, and should functionalize to the TBL a portion of the costs of the conservation and renewable resource programs based on the benefit that each derives from such programs." WPAG Brief, WP-02-B-WA-01, at 15. Yet the WPAG proposal does not link its functionalization percentages to any demonstration of benefits, only to overall costs. As the Joint DSIs argue, WPAG did not present any basis for determining savings in transmission costs from conservation or renewable energy projects. Schoenbeck and Bliven, WP-02-E-DS/AL/VN-06, at 29.

Decision

BPA appropriately functionalized the costs of energy conservation and renewable resources to the generation function.

5.7 Segmentation and Cost Assignment of U.S. Army Corps of Engineers (COE) and Bureau of Reclamation (Reclamation) Transmission Facilities

Issue

Whether BPA should include COE and Reclamation generator step-up transformers (GSU) in the Generation Integration Segment; segment COE and Reclamation transmission facilities to Generation Integration (GI), Integrated Network and Delivery Segments respectively; and assign all GI Segment costs to generation to be recovered in power rates and assign annual costs of COE and Reclamation transmission facilities to Network and Delivery Segments to be recovered in transmission rates.

Parties' Positions

PPLM supports BPA's proposal to recover GSUs in the GI Segment and assign all GI costs to generation to be recovered in power rates. Brooks, WP-02-E-PM-01, at 11-14. WPAG supports BPA's proposal to assign COE and Reclamation transmission costs to the Network and Delivery Segments. Cross *et al.*, WP-02-E-WA-01, at 21.

BPA's Position

BPA proposed to include all of the COE and Reclamation investment and associated annual costs in the generation revenue requirement and generation repayment study, including the costs formerly functionalized to transmission. DeClerck *et al.*, WP-02-E-BPA-27, at 2. BPA proposed to assign the investment for the COE and Reclamation transmission facilities to the GI, Network, or Delivery Segments, and include the cost for COE and Reclamation GSUs in the GI Segment. *Id*. at 2-3. BPA's proposal assigned all of the GI Segment costs to generation to be recovered through power rates, with the remaining COE and Reclamation transmission costs assigned to the Network and Delivery Segments to be recovered through transmission rates. *Id.* at 2-4.

Evaluation of Positions

BPA proposed to include all COE and Reclamation investments in the generation revenue requirement and repayment studies. DeClerck *et al.*, WP-02-E-BPA-27, at 2. BPA's proposal then identified the COE and Reclamation investment in GSUs and transmission facilities and assigns them to transmission segments so that the annual cost associated with these facilities can be developed and assigned to generation or transmission for cost recovery. *Id*. BPA's proposal assigned the investment for the COE and Reclamation transmission facilities to the GI, Network, or Delivery Segments, and includes the cost for COE and Reclamation GSUs in the GI Segment. *Id.* at 2-3. BPA assigns all of the GI Segment costs to generation to be recovered through power rates, and assigned the remaining COE and Reclamation transmission costs to the Network and Delivery Segments to be recovered through transmission rates. *Id.* at 2-4. PPLM supports BPA's proposal to include GSUs in the GI Segment and assign costs to the generation function to be recovered through power rates. Brooks, WP-02-E-PM-01, at 11-14; PPLM Brief, WP-02-B-PM-01, at 10. PPLM claims that all GI costs for Federal generation should be directly assigned to the generation revenue requirement. Brooks, WP-02-E-PM-01, at 12. PPLM concludes that this treatment ensures that non-Federal generation is put on equal terms with Federal generation. Brooks, WP-02-E-PM-01, at 12. PPLM claims that such treatment is consistent with FERC policy articulated in *Kentucky Utilities Co.*, 85 FERC ¶ 61,274 (1999). PPLM Brief, WP-02-B-PM-01, at 10.

BPA's proposal assigned the remaining COE and Reclamation transmission costs to the Network and Delivery Segments to be recovered through transmission rates. DeClerck *et al.*, WP-02-E-BPA-27, at 2, 4. BPA credits the annual cost of the COE and Reclamation Network and Delivery investments (O&M, depreciation, and interest expense) to the generation revenue requirement, and assigns them to BPA's transmission revenue requirement as an expense for the appropriate segment. *Id.* at 4-5. WPAG supports BPA's proposal to assign COE and Reclamation transmission costs to the Network and Delivery Segments. Cross *et al.*, WP-02-E-WA-01 at 21. No party in this rate proceeding raised any legal, policy, or factual issues regarding this proposed treatment in their initial briefs. BPA's Rules of Procedure provide that if a party does not raise and fully develop its position on an issue in its initial brief, then it shall be deemed to take no position on the issue. *Procedures Governing Bonneville Power Administration Rate Hearings*, §1010.13(b).

Decision

BPA has segmented the costs of the COE and Reclamation transmission facilities to GI, Network and Delivery Segments. All GI Segment costs, including COE and Reclamation GSU costs, have been assigned to the generation function. The annual cost for the COE and Reclamation transmission investments and associated costs will be assigned to the Network and Delivery Segments as a transmission expense and recovered in transmission rates.

6.0 RISK ANALYSIS

6.1 Introduction

The objective of the Risk Analysis Study is to identify, model, and analyze the impact that key risks have on BPA's net revenue (revenues less expenses) risk exposure. The impacts of operational risks are quantified through the use of the RiskMod and non-operational risks through the use of the Non-Operating Risk Model (NORM). The results from the Risk Analysis Study are subsequently used in the ToolKit model to evaluate the impact that certain risk mitigation measures have on reducing BPA's net revenue risk, so that BPA can develop rates that cover all its costs and provide a high probability of making its Treasury payments on time and in full during the rate period. In addition to its use in the Risk Analysis Study, WP-02-E-BPA-03, RiskMod is used to calculate the average surplus energy revenues and power purchase expenses reported in the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-02-E-BPA-05.

6.2 RiskMod Model

The RiskMod model quantifies the impact that various Federal load, Federal resource, and wholesale spot market price conditions have on BPA's net revenue risk. Included in these operating risks are the hydro generation impacts of the alternative hydro operations incorporated in the 13 Fish and Wildlife Alternatives under various water supply conditions.

The RiskMod model calculates net revenues (revenues less expenses) using monthly data for HLH and LLH electricity generation, firm loads, surplus energy sales, and power purchases. Monthly HLH and LLH energy values are calculated using load and resource data from the Loads and Resources Study, WP-02-E-BPA-01; HLH and LLH load and resource data not in the Loads and Resources Study, but which are provided by analysts who perform the Loads and Resources Study and the Revenue Forecast component of the Wholesale Power Rate Development Study; and hydro generation data for alternative hydro operations incorporated in the 13 Fish and Wildlife Alternatives. Monthly HLH and LLH hydro generation for each of the 50 water years is estimated by the Hourly Operating and Scheduling Simulator (HOSS) model, which estimates the ability of the FCRPS to shape hydro generation between HLH and LLH under system operational constraints.

Net revenues are calculated using PNW HLH and LLH spot market prices estimated by the AURORA model, WP-02-E-BPA-04; expense data and PF and Industrial Firm Power (IP) rates computed by the Rate Analysis Model (RAM), WP-02-E-BPA-05; and various revenue data from the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-02-E-BPA-05. Monthly HLH and LLH PNW spot market prices from AURORA for the months of April-June under high hydro generation conditions are adjusted downward in RiskMod to better reflect the amount of surplus energy revenues that BPA analysts believe it would receive. Risk Analysis Study Documentation, WP-02-E-BPA-03A.

Issue 1

Whether BPA appropriately estimated the upper price parameters for its linear price adjustment algorithm in RiskMod.

Parties' Positions

The Joint DSIs identified a discrepancy in the prices BPA uses for the upper price parameters in the price adjustment algorithm in RiskMod. This price adjustment algorithm estimates surplus energy prices during high hydro generation conditions in the months of April through June. The Joint DSIs claim that this discrepancy lowers the prices estimated for surplus energy below the prices that would be estimated if BPA correctly implemented the pricing methodology described in BPA's direct testimony. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-03, at 26-27.

BPA's Position

Although no party raised the issue in its initial brief, BPA agreed in its rebuttal testimony to revise its methodology to address the discrepancy identified by the Joint DSIs. Conger *et al.*, WP-02-E-BPA-41, at 5-7.

Evaluation of Positions

BPA revised its methodology to address the discrepancy identified by the Joint DSIs.

Decision

BPA has made changes in the final rates to correct the discrepancy identified by the DSIs to appropriately estimate the upper price parameters for the linear price adjustment algorithm in RiskMod.

6.3 Heavy Load Hour (HLH) and Light Load Hour (LLH) Surplus Energy Sales

Issue 1

Whether it is reasonable for BPA to adjust the AURORA monthly marginal spot market prices downward for the April-June period.

Parties' Positions

The DSIs argue:

> [BPA] staff casts the AURORA prices aside in favor of a "linear price algorithm in RiskMod" (BPA-41, at 6), suggesting that during high water conditions, "it is likely that market participants will understand that [BPA] is limited to the PNW market and has not [sic] alternative load. The seller (BPA) will therefore receive less than marginal clearing prices." *Id.* at 8-9. There is no evidence that this has ever really happened, even in the record water year of 1997. Staff is being unreasonably conservative.

DSI Brief, WP-02-B-DS-01, at 59. The DSIs also suggest that BPA's position in its Draft ROD (at 6-4) is that energy markets do not operate consistent with economic theory. DSI Ex. Brief, WP-02-R-BPA-DS-01, at 12.

<u>BPA's Position</u>

AURORA monthly marginal spot prices for the Q2 (April through June) period are adjusted downward, based upon surplus quantities produced in each month of the 50 water years of record in the April-June period, to account for the impact that large amounts of surplus energy sales have on the prices that BPA receives. Conger *et al*., WP-02-E-BPA-15, at 16. The AURORA prices far exceed prices BPA has received. Tr. 760-61.

Historical data support BPA's adjustments. Conger *et al*., WP-02-E-BPA-41, at 9. The adjustments yield, on average over the 50 water years, reasonable estimates of the prices and resulting surplus energy revenues that BPA will receive during April-June for FY 2002-2006. *Id*. at 10.

<u>Evaluation of Positions</u>

BPA explained the limitations of the AURORA model:

> The AURORA model economically determines resources to be dispatched based on price and thus effectively displaces non-hydro resources as the supply of hydro generation increases. However, the AURORA model makes no distinction of specific suppliers (entities such as BPA) when dispatching resources to meet demand. Under high water conditions during the April, May, and June months, entities such as BPA, that have large portions of the regional hydro supply, cannot sell every megawatt (MW) at the hourly marginal price.

Conger *et al*., WP-02-E-BPA-15, at 16.

BPA further noted that BPA's inability to sell every MW at the hourly marginal price under high water conditions during the months of April-June is primarily due to the following:

- the inability to move large amounts of electric power on an hour-to-hour basis at marginal cost given the absence of a marginal hourly market in the Northwest;

- during high water conditions in the Northwest, the Interties to the Southwest are capacity-constrained, capping access to the California Power Exchange (CalPX), thereby limiting sales from the Northwest that receive hourly marginal prices; and

- during extremely high water conditions, market saturation may occur and water will have to be spilled due to lack of market and inability to store.

Conger *et al*., WP-02-E-BPA-15, at 16-17.

Additional discussion of market limitations can be found in the DSIs' cross-examination of a BPA witness:

> Q. (Mr. Uda) Let us suppose a scenario where you have a lot of short-term energy available, and you cannot get it down through the southern intertie because the intertie is constrained. Under those conditions, how would you describe how the market reacts to what BPA does?
>
> A. (Mr. Lamb) So in that instance, parties are aware of the fact that BPA has a large amount of power to sell, knows that BPA has to move that power, has to move it, cannot, has limited storage capability in which to wait out for prices to recover and will hold out for the lowest price offerings in whatever markets, be it the hourly, the next day, the within month, knowing that we have to move that water and preferably through turbines. Does that --
>
> Q. (Mr. Uda) That was a good answer.

Tr. 817-18.

BPA also noted during cross-examination that competitors and customers know that during April-June, under high water conditions, BPA has a lot of surplus energy to sell, so they can wait until prices drop. Tr. 780-81. BPA staff stated that BPA would prefer to run water through the turbines rather than spill the water over the dams. Tr. 781. AURORA perfectly dispatches the resources by project and simply spills if there is excess generation. Tr. 781. The result is that during these times, the marginal costs estimated by AURORA do not accurately reflect BPA sales of surplus energy and the revenue it will receive. *Id*. at 776-77, 780-81. The downward adjustments of AURORA prices in RiskMod yield, on average over the 50 water years, reasonable estimates of prices and resulting surplus energy revenue that BPA will receive for FY 2002-2006 during the April-June or Q2 period. *Id*. *See also* Conger *et al.*, WP-02-E-BPA-41, at 10. This is not a concession that AURORA does not follow economic theory.

<u>Decision</u>

The downward adjustments made in RiskMod to the monthly marginal spot market prices estimated by AURORA under high streamflows in April-June are reasonable.

<u>Issue 2</u>

Whether BPA's observation is reasonable that it receives reduced prices for its surplus energy sales under high streamflow conditions during the months of April-June because BPA cannot make large anonymous sales.

Parties' Positions

The DSIs argue that "[u]pon cross-examination, [BPA] staff acknowledged that BPA can and does use brokers to buy and sell power anonymously, Tr. at 819-20; so that the market would not necessarily perceive all power to be sold by a "single supplier." DSI Brief, WP-02-B-DS-01, at 59, footnote 26.

BPA's Position

The DSIs have waived this issue, since it is not fully developed in their brief. *Procedures*, §1010.13(b). BPA however, responds to the claim.

BPA uses brokers to buy and sell power, but notes the limitations of such use, particularly with respect to anonymity:

> [Mr. Lamb:] There is a broker market out there . . . They [brokers] do not take ownership, but they do match party to party anonymously.
>
> Now in the real world, when you are marketing power, large amounts of power are being marketed, quickly parties know that there are only a few entities out there marketing. . . . [T]here is a lot of information on the net the parties can see with respect to Chief Joseph and Grand Coulee and make some assumptions that, "Gee, Bonneville has to move power."
>
> In the event of trying to move large amounts anonymously, in my experience, . . . [BPA has a] very limited ability and potential . . . to do so without it being known that [BPA is] out in the market . . . .

Tr. 819-20.

Evaluation of Positions

The DSIs' argument challenges the "single supplier theory." However, the DSIs provide no description of the theory, cite no authority, and do not offer their own description and evidence of market effects that result from BPA, a large supplier of hydroelectric energy, being in the market during the high flow months of April-June. Consequently, the DSIs have waived their argument, since they have not fully developed their argument in their brief. *Procedures*, §1010.13(b).

As BPA noted, "[t]he AURORA model makes no distinction of specific suppliers (entities such as BPA) when dispatching resources to meet demand." Conger *et al.*, WP-02-E-BPA-15, at 16. This is problematic for BPA because "[u]nder high water conditions . . . entities such as BPA, that have large portions of the regional hydro supply, cannot sell every MW at the hourly marginal price." *Id*.

BPA's witness, Mr. Lamb, was "responsible for managing the market-based bulk power product pricing, development of BPA's near-term (up to two years out) forward price curves, market price analysis, near-term inventory tracking, secondary energy revenue analysis, and development of the trading floor technical systems supporting Bulk Power Marketing." WP-02-Q-BPA-40, at 3. In Mr. Lamb's expert professional judgment, "In the event of trying to move large amounts anonymously, in my experience, ...[BPA has a] very limited ability and potential . . . to do so without it being known that [BPA is] out in the market . . ." Tr. 819-20.

BPA's expert judgment is that its ability to market large amounts of surplus power anonymously during its high streamflow conditions during April-June is very limited. Whether or not this refutes the "single supplier" theory, BPA accurately described the basis for which it adjusted AURORA prices in RiskMod, including describing the impacts of the market on BPA's surplus energy revenues under these conditions.

Decision

BPA exercised its expert judgment to conclude that its ability to market large amounts of surplus power anonymously is limited during high streamflow periods (April-June). This assumption was used in part to justify BPA's downward modification of prices during high streamflow conditions. This assumption is reasonable.

Issue 3

Whether BPA should increase predicted revenues by taking account of trading floor activity.

Parties' Positions

The DSIs propose that BPA increase predicted revenues by taking account of trading floor activity. DSI Brief, WP-02-B-DS-01, at 59, footnote 25; DSI Ex. Brief, WP-02-R-DS-01, at 14. In their brief on exceptions the DSIs argue that BPA should take into account both the revenue and the risk associated with trading floor activity. *Id*. at 14.

BPA's Position

The trading floor activities are accounted for by the spot market surplus energy sales and power purchases calculated in RiskMod. Tr. 739-42. Predicted revenues should not be increased, because the DSIs' assumption is erroneous that trading floor activity produces any additional reliable source of revenue not otherwise accounted for in RiskMod. *Id*.

Evaluation of Positions

The DSIs propose that BPA should increase predicted revenues by taking account of trading floor activity. DSI Brief, WP-02-B-DS-01, at 59, footnote 25. BPA disagrees with this proposal. The trading floor activities are adequately accounted for by modeling the spot market surplus energy sales and power purchases calculated in RiskMod. Tr. 739-42. This is not to say that the forward purchases and sales done by the trading floor are without benefit. However, this additional revenue potential carries with it additional supply risk. Thus, surplus net revenues are not understated. Assuming higher revenues and no additional risk as suggested is imprudent, because the size and timing of any additional transactions have not been determined, and BPA could suffer substantial losses as well as gains from such activities. Tr. 746-48. Thus, forecasting revenues from such activities is speculative. Therefore, they are not a source of reliable revenues. BPA has accurately estimated its surplus energy revenues for the FY 2002-2006 rate period using a reasonable and consistent methodology.

Decision

Surplus energy revenues are not understated, and an increase in predicted revenues based on additional speculative trading floor activity is inappropriate.

Issue 4

Whether BPA understates its short-term surplus energy revenues during FY 2002–2006.

Parties' Positions

The DSIs claim that BPA has understated its short-term surplus energy revenues by overestimating the proportion of LLH surplus energy sales and understating the likely prices from its surplus energy sales. DSI Brief, WP-02-B-DS-01, at 56-57; DSI Ex. Brief, WP-02-R-DS-01, at 14. The DSIs make these claims by comparing historical (FY 1997-1999) and forecasted (FY 2002-2006) HLH and LLH energy sales, prices, and revenues. DSI Brief, WP-02-B-DS-01, at 57-60.

BPA's Position

The DSIs have waived this argument, since it is not fully developed in their brief or supported by the evidence in this rate proceeding. *Procedures*, §1010.11(a); and §1010.13(b) and (c). BPA, however, responds to the DSI claim.

BPA has accurately estimated the proportion of LLH surplus energy sales and the likely prices from its surplus energy sales for the FY 2002-2006 rate period. Conger *et al.*, WP-02-E-BPA-41, at 2-11. The DSIs have introduced new analysis that is not part of the record, and erroneously ascribed to the HOSS model the differences between historical HLH and LLH surplus energy sales and forecasted HLH and LLH surplus energy sales calculated in RiskMod. Conger *et al.*, WP-02-E-BPA-41, at 5; Tr. 749-50.

Evaluation of Positions

The Joint DSIs sponsored direct testimony (Schoenbeck *et al.*, WP-02-E-DS/AL/VN-03, at 19-36), but no rebuttal testimony, regarding BPA's estimates of the proportion of LLH and HLH surplus energy sales, BPA's adjustments to prices estimated by the AURORA model during the months of April through June, and the accuracy of hydro generation shaped between HLH and LLH by the HOSS model. The DSI initial brief, WP-02-B-DS-01, does not cite their own analyses or the analyses of other parties. Instead, the DSIs introduce new comparisons not previously on the record. They perform these new comparisons using both data in BPA's rebuttal testimony, Conger *et al.*, WP-02-E-BPA-41; and data provided in data responses that are not part of the rate case record. BPA responds to the DSIs' new comparisons, although their non-compliance with rules of the hearing results in their waiver of all arguments which depend on evidence that is not part of the rate case record. *Procedures*, §1010.11(a); 1010.13(b) and (c).

The DSIs note that actual HLH surplus energy sales averaged 61 percent of surplus energy sales from FY 1996-1999, whereas BPA is forecasting an average of 46 percent of surplus energy sales during HLH during FY 2002-2006. DSI Brief, WP-02-B-DS-01, at 57. The DSIs indicate that BPA staff stated that HLH firm sales are "materially different" during the FY 2002-2006 rate period compared to FY 1996-1999. *Id.* at 58. Also, the DSIs indicate that BPA states that some of the HLH and LLH difference arises from future changes in dam operations for fish during the rate period. But, based on the testimony of BPA's witness, Tr. 849, these operational changes are of lesser magnitude and began in 1995 and 1998, so that they are reflected in much of the historical period with higher percentages of HLH sales. *Id.*

The DSIs claim that BPA's explanation for these differences does not account for the magnitude of the predicted changes in BPA's forecast for FY 2002-2006. *Id.* In support of their claim, the DSIs compare actual LLH surplus energy sales under very high streamflow conditions in FY 1997 (January-July runoff of 159.0 million acre feet (MAF) and forecasted LLH surplus energy sales in FY 2004 for water year 1974 (January–July runoff of 157.0 MAF). The DSIs note that the forecasted LLH sales in FY 2004 for water year 1974 are roughly 3,000 aMW higher. DSI Brief, WP-02-B-DS-01, at 58. The DSIs note that differences between the HOSS-predicted LLH generation and actual historical sales are significant. *Id.* Thus, the DSIs ascribe these differences to the way that the HOSS model shapes hydro generation between HLH and LLH.

In addition to claiming that BPA is underpredicting the proportion of HLH surplus energy sales, the DSIs argue that BPA is using lower prices for LLH surplus energy sales than either AURORA or recent history would predict. DSI Brief, WP-02-B-DS-01, at 58; DSI Ex. Brief, WP-02-R-DS-01, at 12-13. The DSIs note that from 1997-1999, BPA earned an average of $49 million per year from second quarter LLH sales compared with BPA forecasts of just $38 million per year from second quarter LLH sales during the current rate period. DSI Brief, WP-02-B-DS-01, at 58-59; DSI Ex. Brief, WP-02-R-DS-01, at 13. Also, they argue that BPA projects average second quarter LLH sales of 5,633 aMW at an average LLH price of $7.30, yet in 1999 and 1997, with sales of 5,605 and 7,415 aMW, prices averaged $11.40/MWh and $7.90/MWh. DSI Brief, WP-02-B-DS-01, at 59. Based on this comparison, the DSIs argue that BPA's LLH price adjustments in RiskMod result in average LLH prices for second quarter LLH sales that are below the LLH prices it obtained in the wettest year of record. DSI Brief, WP-02-B-DS-01, at 59; DSI Ex. Brief, WP-02-R-DS-01, at 13.

Based on these comparisons, the DSIs disagree with the price adjustments BPA makes in RiskMod that modify the prices forecasted by AURORA during April-June, which lower BPA's estimates of surplus energy revenues during these months relative to what would have been forecasted without these adjustments to prices from AURORA. DSI Brief, WP-02-B-DS-01, at 59. The downward adjustment of prices is also addressed *supra*, at Issue 1. The DSIs downplay BPA's statement that AURORA does not take into account the effect of a single supplier with respect to the disposition of inventory under high hydro generation conditions. *Id.* at 59-60. They claim that there is no evidence that this really happened, and that BPA does use brokers to buy and sell power anonymously, so the market would not necessarily perceive all power to be sold by a single supplier. *Id.* Also, the DSIs propose that BPA should increase predicted revenues by taking account of trading floor activity, which they claim was not reflected in BPA's risk modeling. *Id.* at 59. *See* Issue 3, *supra*.

The DSIs argue that their claims are supported by a comparison of the differences between annual surplus energy revenues and power purchase expenses (which they refer to as "net revenues") in FY 1998 and 1999 and average annual "net revenues" for the 50 water years for FY 2002-2006. DSI Brief, WP-02-B-DS-01, at 60. The DSIs argue that the forecasted "net revenues" are more than $100 million less per year than recent experience. *Id*. The DSIs indicate that it is inappropriate to base rates on rising purchase power costs while, at the same time, depressing the credit for short-term surplus energy revenues. *Id*.

The DSIs' initial brief addresses only one of several explanations that BPA provides regarding the reasons for the differences in the proportion of historical and forecasted HLH and LLH surplus energy sales they identify. Conger *et al*., WP-02-E-BPA-15, at 16-17. By ignoring BPA's complete set of explanations, the DSIs' assessment is incomplete and flawed. These omissions cause the DSIs to erroneously attribute the differences between historical HLH and LLH surplus energy sales and forecasted HLH and LLH surplus energy values calculated in RiskMod to the HOSS model and the way it shapes hydro generation between HLH and LLH. *See* Issue 4, *supra*. The DSIs inappropriately compare historical (FY 1997-1999) and forecasted average HLH and LLH sales, prices, and revenues during FY 2002-2006 to argue against BPA's adjustments to the prices estimated by AURORA during the months of April-June. Further, the DSIs' citation of BPA's resources panel testimony at Tr. 849 does not support their position, because the resources panel was not able to make any statements regarding the impact of changes in hydro operations in 1995 and 1998 on the proportion of HLH and LLH hydro generation when the DSIs raised the issue for the first time during cross-examination. Tr. 848-61. Accordingly, the assertion attributed to BPA is not in evidence. *Compare* DSI Brief, WP-02-B-DS-01, at 58, *with Procedures*, §1010.11.

BPA's rebuttal testimony, Conger *et al.*, WP-02-E-BPA-41, at 4-5; direct testimony, Conger *et al.*, WP-02-E-BPA-15, at 16-17; and cross-examination, Tr. 761-62 and 779-83, describe several different elements that explain why the percentage of HLH surplus energy sales is forecasted to be lower for the FY 2002-2006 rate period than during FY 1996-1999. First, more shaped firm loads during FY 2002-2006 are being served with additional flat energy resources, *i.e.,* flat system augmentation purchases and increased flat energy output from the WNP-2 nuclear plant. Conger *et al.,* WP-02-E-BPA-41, at 4. Second, there have been reductions (since 1998) in hydro generation due to changes in hydro operations that result in operational spill. *Id*. Third, changes in hydro operations (since 1998) reduce the capability of the hydrosystem to shape hydro generation into HLH. *Id.* at 5. Fourth, unlike the surplus and deficit energy values calculated by RiskMod, the historical data for FY 1996-1999 reflect the impact of the reduction in hydro generation from spilling water due to market saturation conditions (market saturation spill), which occurs mostly during LLH. Conger *et al.*, WP-02-E-BPA-41, at 4; Tr. 761-62, 779-83.

The DSIs' initial brief introduces a new comparison between actual LLH surplus energy sales under very high streamflow conditions in FY 1997 (January-July runoff of 159.0 MAF) and forecasted LLH surplus energy sales in FY 2004 for water year 1974 (January-July runoff of 157.0 MAF). DSI Brief, WP-02-B-DS-01, at 58. According to the DSIs, the way the HOSS model shapes hydro generation between HLH and LLH explains why forecasted LLH surplus energy sales in FY 2004 for water year 1974 (during the months of April-June) are roughly 3,000 aMW higher. *Id.* This comparison was not made by the parties during either direct or rebuttal testimony and is waived. *Procedures,* §1010.11 and 1010.13.

The DSIs' claim that HOSS is the source of the difference of 3,000 aMW during LLH is waived and also erroneous. HOSS is a hydroregulation model that estimates the amount of HLH and LLH hydro generation that can be produced by the Federal System under various streamflow conditions based on hydro operation constraints. Tr. 856. As a hydroregulation model, HOSS does not take into account whether or not there is a market for all the HLH and LLH surplus energy that can be produced by the Federal System. RiskMod does not reflect the impact of market saturation spill conditions on surplus energy revenues. Tr. 779. The HOSS input to RiskMod is similar in that it describes only potential generation, not market limitations or revenue. Tr. 782; Risk Analysis Study Documentation, WP-02-E-BPA-03A, at 9.

The HLH and LLH surplus energy values calculated in RiskMod for water year 1974 include loads and resources (including WNP-2 output under biennial maintenance schedules) documented in the Loads and Resources Study, WP-02-E-BPA-01, at 32-43; Federal Hydro Generation for the 50 water years from the Hydroregulation, Loads and Resources Study Documentation, WP-02-E-BPA-01A, at 34-36; and HLH and LLH hydro generation ratios from the HOSS model, Risk Analysis Study Documentation, WP-02-E-BPA-03A, at 12. The surplus energy values calculated by RiskMod reflect materially different firm loads and resources during FY 2002-2006 than during the current rate period (which includes FY 1997) and do not reflect spillage of energy due to market limitations. Conger *et al.*, WP-02-E-BPA-41, at 3-5; Tr. 761-62, 779-83.

The DSIs note that streamflow conditions during January-July in FY 1997 are the highest on record. DSI Brief, WP-02-B-DS-01, at 60. This conclusion is supported by data from 1929-1999. *See* Conger *et al*., WP-02-E-BPA-41, Attachment 1, at 18. Accordingly, actual LLH surplus energy sales during April-June of FY 1997 should closely approximate the maximum amount of LLH energy that can be marketed, with the remaining potential generation being spilled. The DSIs fail to account for this phenomenon in their assessment.

Instead, the DSIs emphasize the 3,000 aMW more LLH surplus energy calculated by RiskMod in FY 2004 for water year 1974 during the months of April-June than LLH surplus energy sales in FY 1997 during the months of April-June. The DSIs fail to note that BPA's initial proposal showed that HLH surplus energy calculated by RiskMod in FY 2004 for water year 1974 during the months of April-June is also approximately 740 aMW higher than the HLH surplus energy sales during April-June in 1997. Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A. Additionally, the higher HLH surplus energy sales of 740 aMW during April-June in FY 2004 for water year 1974 include the impact of changes in firm loads and resources stated in BPA's testimony that reduce HLH surplus energy sales during FY 2002-2006 relative to the current rate period (which includes FY 1997). Conger *et al*., WP-02-E-BPA-41, at 3-5.

Both HLH and LLH surplus energy values calculated in RiskMod for water year 1974 (which are based on lower January-July streamflows than in 1997) are higher during both HLH and LLH periods. The additional 3000 aMW of LLH surplus energy sales that the DSIs use as the foundation of their argument that HOSS overstates LLH hydro generation at the expense of HLH hydro generation is flawed, because lower streamflow conditions during water year 1974 produce more HLH and LLH surplus energy sales in RiskMod. Thus, how HOSS shapes hydro generation between HLH and LLH is irrelevant, because market saturation spill and differences in firm loads and resources explain the difference in LLH surplus energy sales. These factors were discussed by BPA, but ignored by the DSIs.

BPA adjusts the prices estimated by AURORA downward under high streamflow conditions during the months of April-June, when the Federal system is awash with power, to reflect that all surplus energy calculated in RiskMod cannot be sold, but energy will be spilled due to lack of market. Conger *et al*., WP-02-E-BPA-15, at 16-17; Conger *et al*., WP-02-E-BPA-41, at 7-11; Tr. 759-67, 779-83. Also, BPA becomes a single supplier and cannot earn the prices forecasted by AURORA under high hydro generation conditions, because BPA cannot sell such large quantities anonymously. *See* Conger *et al*., WP-02-E-BPA-15, at 16-17; Conger *et al*., WP-02-E-BPA-41, at 8-9; Tr. 818-20.

In BPA's experience, the power marketing group sometimes uses brokers to sell small amounts of power anonymously. Tr. 819. In the real world when large amounts of power are marketed during high streamflow conditions, parties quickly know that BPA is one of a very few entities likely to have such large volumes of power available for sale. Tr. 819-20. *See also* Issue 2, *supra*. Parties are able to see the status of BPA resources such as Chief Joseph and Grand Coulee, make assumptions, and wait for BPA to reduce the price of power (below the marginal cost). Tr. 819-20. The DSIs suggest that BPA can sell large amounts of power anonymously through brokers, DSI Brief, WP-02-B-DS-01, at 59, but this has not been BPA's experience. Tr. 819-20.

The DSIs' observation that there is 3,000 aMW more LLH surplus energy, and BPA's observation that there is 740 aMW more HLH surplus energy, calculated by RiskMod in FY 2004 for water year 1974 during the months of April-June than LLH and HLH surplus energy in FY 1997 during the months of April-June requires that BPA either adjust the amount of energy and/or the prices for its surplus energy sales when calculating surplus energy revenues under high hydro generation conditions. Otherwise, BPA would substantially overstate its surplus energy revenues. For instance, BPA testified, Tr. 759-67, 779-83, that it is inconceivable that BPA could sell 11,000-15,000 aMW of LLH surplus energy at the AURORA price of approximately $12 megawatthour (MWh) in June of 2002. *See* Conger *et al*., WP-02-E-BPA-41, Attachment 1, at 7, describing the amount of LLH surplus energy and the associated AURORA price in June. BPA sold 7,415 aMW of LLH surplus energy at $7.90/MWh during April-June in

1997 (the highest January-July streamflows from 1929 through 1999). *Id.*, Attachment 1, at 16. Both the price and the quantity for LLH surplus energy sales during April-June of 1997 are substantially below the $12/MWh estimated by AURORA and the 11,000-15,000 aMW of LLH surplus energy calculated in RiskMod. Accordingly, BPA would substantially overstate the surplus energy revenues that it could earn under such high streamflow conditions unless adjustments are made to either the amount of surplus energy calculated by RiskMod (which does not account for market saturation spill and WNP-2 displacement) and/or the prices estimated by AURORA. Tr. 759-67, 779-83.

BPA's adjustments to AURORA prices in RiskMod are made because the adjustments yield reasonable forecasted surplus energy revenues under high hydro generation conditions. *See* Conger *et al.*, WP-02-E-BPA-41, at 9-11; Tr. 759-67, 779-83. Using the example from the DSIs' initial brief, between April-June in FY 1997 and FY 2004 for water year 1974, actual total surplus energy revenues for April-June in FY 1997 were $140.6 million, Conger *et al*., WP-02-E-BPA-41, Attachment 1 at 16; and forecasted total surplus energy revenues reported in tables in the Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 196, 199 during April-June in FY 2004 for water year 1974 are $158.7 million. The increase in forecasted surplus energy revenues of $18.1 million during April-June of FY 2004 under such high water conditions is reasonable.

The DSIs also claim that BPA uses lower prices for LLH surplus energy sales than recent history would predict. DSI Brief, WP-02-B-DS-01, at 58. In their initial brief, the DSIs argue for the first time that from 1997-1999, BPA earned an average of $49 million per year from second quarter LLH sales compared with BPA's forecasts of an average of $38 million per year from second quarter LLH sales during the rate period. *Id.* at 58-59. In their initial brief, the DSIs also note for the first time that BPA's LLH price adjustments in RiskMod result in average LLH prices for second quarter LLH sales that are below the LLH prices it obtained in the wettest year of record. DSI Brief, WP-02-B-DS-01, at 59; *see also*, DSI Ex. Brief , WP-02-R-DS-01, at 13. This comparison was not made during either direct or rebuttal testimony and is waived. *Compare* DSI Brief, WP-02-B-DS-01, at 58-60, with *Procedures*, §1010.11 and §1010.13.

Since rates are calculated using total (HLH and LLH) surplus energy revenues, rather than just LLH surplus energy prices and revenues, BPA's criterion for making adjustments to HLH and LLH surplus energy prices in RiskMod was that the HLH and LLH price adjustments, in total, produced reasonable total surplus energy revenues under high streamflow conditions during April-June in FY 2002-2006. Conger *et al*., WP-02-E-BPA-41, at 10. BPA demonstrated that forecasted average surplus energy revenues (HLH and LLH) in FY 2002-2006 during April-June are roughly 2 percent ($3 million) lower than the average total surplus energy revenues during 1997-1999. The forecasted average surplus energy revenues (an average for the 50 Water Years) during FY 2002-2006 are reasonable, since the forecasted average surplus energy revenues are indicative of surplus energy revenues for average January through July runoff volumes (the mean of the January through July runoff volume for the hydro study Water Years 1929 through 1978), while the historical surplus energy revenues are based on much higher January through July runoff volumes for years 1997, 1998, and 1999 that were 154, 101, and 120 percent of the average January through July runoff volumes. *Id.*

BPA also compared forecasted average surplus energy revenues during April-June in FY 2002-2006 with average surplus energy revenues during April-June in year 1998 (when January to July runoff volume was 101 percent of average) and found that forecasted surplus energy revenues were $15 million higher, a reasonable value. Conger *et al*., WP-02-E-BPA-41, at 11. Additionally, the surplus energy revenues are reasonable given that surplus energy revenues during FY 2002-2006 are based on lower proportions of HLH surplus energy sales (which receive higher prices) and higher proportions of LLH surplus energy sales relative to the current rate period (which includes 1998), for reasons previously discussed in Issue 4, *supra*. BPA's forecasted total surplus energy revenues for April-June in FY 2002-2006 are reasonable when they are reviewed in their entirety, rather than focusing on piecemeal and incomplete comparisons between historical and forecasted LLH prices and revenues, as the DSIs have done. *Id*.

In their initial brief, the DSIs introduce for the first time a table that compares the difference in annual surplus energy revenues and power purchase expenses in FY 1998 and FY 1999 and average annual "net revenues" for the 50 water years for FY 2002-2006. DSI Brief, WP-02-B-DS-01, at 60. Based on this comparison, they indicate that the forecasted "net revenues" are more than $100 million less per year than recent experience. *Id.* This comparison was not made during either direct or rebuttal testimony and is waived. *Compare* DSI Brief, WP-02-B-DS-01, at 60, *with Procedures*, §1010.11 and §1010.13.

The DSIs' analysis is based on BPA responses to data requests (DS-BPA 113SS, 114SS, 115SS, and 116SS) that are not a part of the rate case record. DSI Brief, WP-02-B-DS-01, at 60. The DSIs attribute the data used in their analysis to BPA data. *Id.* BPA included in its rebuttal testimony only Data Responses DS-BPA 115S and DS-BPA 116S. Conger *et al.*, WP-02-E-BPA-41, Attachments 2 and 3. The data responses with the double letters "SS" mentioned above are data responses that include updated data that was consistent with information provided previously in "S." However, the DSIs could have included the BPA data responses with "SS" (DS-BPA 113SS, 114SS, 115SS, and 116SS) in their testimony or even submitted them for admission as part of the cross-examination of BPA witnesses. *Procedures*, §1010.11 and §1010.12. They did neither. Instead, the DSIs introduce them in their initial brief. This portion of the DSIs' argument is waived. *Procedures*, §1010.11 and §1010.12. Should the DSIs argue that either a scrivener's error or excusable oversight has occurred, they are no better off. The surplus energy revenues in FY 1999, based on the DSIs' cite to BPA's testimony, Conger *et al*., WP-02-E-BPA-41, Attachment 2-3, are $250.65 million less than that reported in the DSIs' initial brief. Thus, the data attributed to BPA's evidence by the DSIs shows that their analysis is flawed. *See*, DSI Brief, WP-02-B-DS-01, at 60; Conger *et al*., WP-02-E-BPA-41, Attachment 2-3; and *Procedures*, §1010.11 and §1010.13.

The DSIs' analysis is also flawed because it ignores major differences in loads and resources between year-specific data for FY 1998-1999 and average data for FY 2002-2006. The amounts of annual surplus energy sales and the proportion of HLH and LLH surplus energy sales during these years are materially different between FY 1998-1999 and FY 2002-2006. Surplus energy revenue during FY 1998-1999 should be much higher, since both the amount of annual average surplus energy sales and the proportion of surplus energy sales during HLH is substantially higher during FY 1998-1999 than in FY 2002-2006. Conger *et al*., WP-02-E-BPA-41, Attachment 1, at 1. The DSIs' analysis ignores the changes in firm loads and resources for FY 2002-2006. They also make a faulty comparison of "net revenues" by comparing atypical recent conditions (wetter than average, January-July streamflow conditions) in FY 1998-1999 with typical average conditions (lower January-July streamflows conditions reflected in the 50 water years) in FY 2002-2006. Conger *et al*., WP-02-E-BPA-41, Attachment 1, at 18.

The DSIs also make a new argument that it is inappropriate to base rates on rising purchase power costs while depressing the credits for surplus energy revenues. DSI Brief, WP-02-B-DS-01, at 61. However, the DSIs' analysis, DSI Brief, WP-02-B-DS-01, at 60, does not support this argument. A table in the DSIs' brief shows that for FY 2002-2006, forecasted surplus energy revenues rise by $81.1 million (from $443.5 million to $524.6 million), while power purchase costs rise by $2.1 million (from $94.8 million to $96.9 million). *Id.* Because surplus energy revenues are forecasted to rise substantially more than power purchase costs, the conclusion that BPA is depressing credits for surplus energy revenues while basing rates on rising power purchase costs is not borne out by the information the DSIs employ. Their argument is without merit.

Decision

BPA accurately estimated its surplus energy revenues for the FY 2002-2006 rate period using a reasonable and consistent methodology. Surplus energy revenues are not understated.

Issue 5

Whether the failure to disclose BPA's proprietary HOSS model to parties invalidates the risk analysis panel's evidence and, therefore, the 2002 rates.

Parties' Positions

In their initial brief, the DSIs argue for the first time that BPA's failure to share its proprietary HOSS model (which estimates the amount of HLH and LLH hydro generation that the FCRPS can produce under various streamflow conditions) results in insufficient evidence to support BPA's risk analysis and, therefore, to set BPA's rates. DSI Brief, WP-02-B-DS-01, at 57. "Unless and until the model and its inputs are produced, BPA will not have put forth evidence in the record on which it can lawfully set rates. The DSIs and all customers are entitled pursuant to section 7(i) to test staff's assertions." *Id*. The DSIs suggest that BPA's "explanations do not cover the magnitude of predicted changes." *Id*. at 58. Finally, the DSIs suggest that BPA has denied the parties an opportunity to rebut its evidence. DSI Ex. Brief, WP-02-R-DS-01, at 16.

BPA's Position

The DSIs have waived this issue, since the DSIs did not seek disclosure of the model under existing rate case procedures and they did not fully develop their argument in their brief. *Procedures*, §1010.8(b), (e), and (f), and §1010.13(b). Moreover, the parties received sufficient information to overcome any limitations in their inability to access and assess BPA's proprietary

HOSS model. Risk Analysis Study Documentation, WP-02-E-BPA-03A, at 9; Conger *et al*., WP-02-E-BPA-41, at 2-5. Nevertheless, BPA responds to the DSIs' claim.

<u>Evaluation of Positions</u>

The HOSS model estimates the ability of the FCRPS to shape average monthly hydro generation into HLH hydro generation under various streamflow conditions (the 50 water years). Risk Analysis Study Documentation, WP-02-E-BPA-03A, at 92. This ability is measured as ratios or the proportion of average energy that can be shaped into HLH. *Id.* It is reported in a 50 x 12 table. *Id*. at 12.

Although the DSIs requested HOSS as part of their discovery, BPA asserted that it is proprietary, which is a response permitted by the rules. *Procedures*, §1010.8 (e), (f), and (g). However, BPA provided the DSIs and other parties alternative data, which allowed adequate analysis of BPA's risk analysis, including whether BPA's use of HOSS produced the differences between historical and forecasted outcomes that the DSIs attempt to exploit or, more generally, whether HOSS produced unreasonable results which might invalidate the risk analysis. Little of this data has been made a part of the rate case record, because the DSIs did not address the issue during the evidence-gathering portion of the rate case as the discovery rules require. *Procedures*, §1010.8(b), (e), and (f). Instead, the DSIs attempt to circumvent the rate case procedures by arguing late, and with little support, that, "[u]nless and until the model and its inputs are produced, BPA will not have put forth evidence in the record on which it can lawfully set rates. The DSIs and all customers are entitled pursuant to section 7(i) to test staffs [sic] assertions." DSI Brief, WP-02-B-DS-01, at 57.

The DSIs cited many BPA data request responses, but none explicitly related to HOSS, its operation or output. Data Responses in DSI Testimony, WP-02-E-DS/AL/VN-05. The Risk Analysis uses HOSS to produce monthly HLH hydro generation (50 water year) data. In turn, BPA derives HLH and LLH Federal hydro generation ratios. Risk Analysis Study Documentation, WP-02-E-BPA-03A, at 12. Historical data BPA provided and more precise questions might have been asked given the extended open discovery that has characterized this rate case. Information available and accessible to the DSIs could easily have been used to evaluate whether HOSS estimates of HLH and LLH generation follow historical patterns (under comparable water conditions) or whether they produce reliable results for the risk analysis. The DSIs could have used such information to evaluate BPA's explanations in rebuttal testimony, Conger *et al*., WP-02-E-BPA-41, at 2-5; Conger *et al*., WP-02-E-BPA-15, at 7; Tr. 750, 760-84.

BPA specifically addressed the DSIs' suggestion that HOSS accounts for differences in BPA's forecasted HLL and LLH surplus energy sales for FY 2002-2006 and historical HLH and LLH surplus energy sales. Conger *et al*., WP-02-E-BPA-41, at 5. Moreover, BPA has addressed the differences the DSIs raise respecting BPA's forecasted HLH and LLH surplus energy sales. *Id.;* Tr. 750, 760-84. The Parties including the Joint DSIs received adequate information to test the risk analysis element of BPA's rate case. Finally, BPA's evidence also established that the use of HOSS in the risk analysis is reasonable. *See* Issues 2-4, *supra.*

The rate case discovery rules directly address the issue the DSIs raise for the first time here:

- Motions to compel. Anyone whose data request or clarification question is not answered may file a motion with the hearing officer to compel an answer. The movant must certify that it first attempted to resolve the objection informally with the objecting party. Motions to compel must be made within the time specified in the procedural schedule.

- Privileged Information. The hearing officer may issue protective orders or make in camera inspection of documents as necessary to protect copyrighted, proprietary, or otherwise privileged information. The hearing officer may not order release of documents in BPA's possession withheld on the basis of exemptions to the *Freedom of Information Act,* 5 U.S.C. §552, or the *Trade Secrets Act*, 18 U.S.C. §1905.

- Sanctions. The hearing officer may remedy any refusal to comply with an order compelling answer to a data request or clarification question by:

  (1) Striking the testimony or exhibits to which the question or request relates; or

  (2) Limiting discovery or cross-examination by the party refusing to answer or respond; or

  (3) Recommending to the Administrator that an appropriate adverse inference be drawn against the party refusing to answer or respond.

Procedures, §1010.8(e), (f), and (g).

Since the DSIs made a tactical choice to ignore the rules, BPA's data and analysis, they cannot argue that BPA's failure to deliver its proprietary model HOSS invalidates the Risk Analysis Study. *Id.*

HOSS is proprietary. BPA unequivocally noted this status to the DSIs and other parties. Because this issue is being raised for the first time in the DSI brief, BPA's ability to mount an especially complete defense is limited to arguments and comparisons of data which can be gleaned from information on the record. That record shows BPA's consistent treatment of the HOSS information as proprietary. It shows disclosure of compiled historical HLH and LLH surplus energy sales and revenues and HOSS outputs. The record also provides reasonable explanations for differences in HLH and LLH surplus energy sales to establish that these differences are not attributable to HOSS. Tr. 750, 760-84. On the whole, this information allows parties to confirm the accuracy of the risk analysis, including the HOSS related elements.

Finally, the DSI argument is insufficiently developed for this rate case. *Procedures,* §1010.13(b). The argument contains no analysis, only the conclusions that BPA's analysis is invalid and BPA's failure to provide the HOSS model injured the DSIs.

BPA's use of the HOSS model in the development of its Risk Analysis is reasonable. In light of the timing and inadequate argument of the DSIs, the argument must be rejected because it has been waived. Even if withholding the HOSS model by BPA is error, the error is not harmful. BPA provides adequate explanations for differences in HLH and LLH surplus energy sales in RiskMod compared with historical data, and alternative information by data request responses, which would allow parties to confirm the accuracy of the risk analysis, including the HOSS related elements. BPA's risk analysis was not invalidated by its decision to withhold release the HOSS model as proprietary.

Decision

BPA's refusal to provide the proprietary HOSS model to parties invalidates neither the risk analysis panel's evidence nor the 2002 power rates.

6.4 Non-Operating Risk Model (NORM)

The NORM quantifies BPA's non-operating risks including the uncertainties in capital costs and expenses (but not operational impacts) associated with the 13 Fish and Wildlife Alternatives identified in the Principles. NORM also quantifies the uncertainty in achieving cost reductions identified in the Cost Review recommendations, costs associated with business line separation, and costs associated with conservation and renewable resources.

Issue 1

Whether BPA is understating the risk that WNP-2 will not be operating due to age and other factors.

Parties' Positions

UCUT claims that the BPA risk analysis has not accounted for the risk of higher operating expenses of WNP-2 as it ages and the risk that the nuclear reactor will not be operating and could require decommissioning. UCUT Brief, WP-02-B-UC-01, at 24.

BPA's Position

BPA addressed this issue in its rebuttal testimony. Conger *et al*., WP-02-E-BPA-41, at 13-15. Though not all costs would be covered, the insurance coverage BPA maintains for WNP-2 is sufficient to justify not including the risks in NORM. *Id*.

Evaluation of Positions

UCUT raises this issue for the first time in its initial brief. Consequently, the argument is waived. *Procedures*, §1010.11(a) and §1010.13(b), and (c).

BPA carries both business interruption and property insurance and pays into a decommissioning fund. Conger *et al.*, WP-02-E-BPA-41, at 13-15. This insurance would cover many of the costs associated with prolonged closures due to accidents or expensive repairs. *Id*. Though not all costs would be covered, the insurance is sufficient to justify not including the risks in NORM. *Id*.

Decision

BPA has sufficient insurance coverage on WNP-2 that it justifies not including this risk in NORM.

Issue 2

Whether BPA should modify its risk analysis to include a range of probabilities that BPA's CRAC will not be implemented as designed.

Parties' Positions

CRITFC/Yakama argue that BPA's risk analysis should include a range of probabilities between 0 and 100 percent that CRAC will not be implemented, with equal weighting in the range. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 56. CRITFC/Yakama argue that their initial brief described unrebutted evidence that BPA has never successfully implemented a cost recovery or interim rate adjustment (IRA). CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 21-22. They state that BPA's assumption that there is a 100 percent probability that it can and will do something that it has not done before is arbitrary and capricious. *Id*. at 22. They state: "There is also evidence on [ROD page] 7-24 where Bonneville believes a more robust CRAC would be difficult to implement. This raises the obvious question how BPA knows that the CRAC that it has proposed will be 100 percent successful. Bonneville has no basis in the record for its assumption that it will be able to trigger a CRAC successfully." *Id*.

Also, "UCUT agrees with NEC that BPA should model at least some probability that a CRAC will not be able to be implemented." UCUT Brief, WP-02-B-UC-01, at 29.

BPA's Position

BPA rebutted this argument in rebuttal testimony. Conger *et al*., WP-02-E-BPA-41, at 15. BPA is confident that CRAC will be successfully implemented as designed, so it is reasonable not to model the non-implementation of CRAC. *Id*. The appropriate standard for review of this rate case is addressed in ROD sections 1.4 and 6.7.

Evaluation of Positions

CRITFC/Yakama argue that BPA should model a full range of possibilities that CRAC would not be implemented. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 56. UCUT supports this position. UCUT Brief, WP-02-B-UC-01, at 29. Such modeling is not appropriate for this rate case for several reasons. First, CRITFC/Yakama do not provide evidence to support the proposal. *See Procedures*, §1010.11. While CRITFC/Yakama note that BPA has never successfully implemented a CRAC or IRA, they have provided no evidence that BPA has ever failed in implementation of a CRAC or IRA. BPA has never attempted to implement a CRAC or IRA, so there is no record of success or failure.

Second, BPA has decided that CRAC will be implemented. It would be illogical to model non-implementation, because CRAC is a part of the 2002 rates and triggers automatically. Conger *et al*., WP-02-E-BPA-41, at 15.

CRITFC/Yakama also argue that it is arbitrary and capricious of BPA to assume it will be able to implement this rate feature. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 21. BPA has often introduced new rates or new rate features. It has not ascribed a probability of its being unable to implement these new rates or rate features. It is within the Administrator's discretion to introduce new rates and new rate features, subject to applicable statutes and regulations. *Alcoa v. BPA*, 903 F.2d 585, 595-599 (9th Cir. 1989). And it is within the Administrator's discretion to determine for the purposes of a rate proposal if there is a substantial risk that the rates or rates features will be unimplementable. *Id*.

Third, CRITFC/Yakama make a factual argument which was not part of their proposal, so the argument has been waived. *Procedures*, §1010.11(a) and §1010.13(b) and (c). BPA pointed out the limitations of the argument in its rebuttal testimony. Conger *et al*., WP-02-E-BPA-41, at 15.

CRITFC/Yakama argue that in a previous rate period, when financial pressures were closer to triggering an IRA, BPA cut costs and the IRA did not trigger. Lothrop, WP-02-E-CR/YA-02, at 10-11. There is nothing unreasonable about cutting costs. It is a regular part of BPA's responsibility to employ sound business principles. *See, e.g*., *Department of Water & Power of the City of Los Angeles v. Bonneville Power Admin.*, 759 F.2d 684, 693 (9th Cir. 1985). CRITFC/Yakama argue, though, that some of the costs cut at that time were fish and wildlife costs, and that cuts of this sort would be incompatible with Fish and Wildlife Funding Principle No. 1. *Id*. That Principle was not in place at the time of the example cited by CRITFC/Yakama, so the example is not particularly relevant to the present circumstance. Moreover, BPA has made a firm and highly public commitment to the Principles, a commitment that has been endorsed by the Administration. DeWolf *et al*., WP-02-E-BPA-13, at 7. BPA *will* meet all of its fish and wildlife obligations once they have been established. Hansen *et al*., WP-02-E-PP-09, Attachment B.

Decision

It is reasonable for BPA not to model the non-implementation of CRAC in its risk analysis, since CRAC is designed to trigger automatically after the reserve threshold shortage has been confirmed.

Issue 3

Whether BPA's risk analysis properly reflects the possibility that a portion of the 1996 MOA carryforward will be programmed to the current rate period.

Parties' Positions

CRITFC/Yakama argue that BPA has inadequately accounted for the risk that the MOA funds could be reallocated among categories and expended either before the current rate case ends or during the upcoming rate period. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 38.

NEC/SOS recommends that BPA model the uncertainty that some of the carryforward balance will be reallocated. Weiss, WP-02-E-NA-01, at 19.

CRITFC/Yakama maintain that the *"de minimus"* reallocation of MOA funds merely "shows that Bonneville is unwilling to act in good faith when it comes to fish and wildlife issues." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 39.

BPA's Position

In the proposal, BPA did not model the uncertainty that the MOA carryforward balance would be reallocated and expended prior to FY 2002. Lovell *et al.*, WP-02-E-BPA-40, at 23-24. However, risk distributions have been added to the NORM for FY 2000 and FY 2001 to calculate the final rates to determine the risk-adjusted beginning reserves for FY 2002. *Id*. at 24. BPA has modeled the following probabilities in NORM: a 50 percent chance that none of the carryforward balance will be reallocated, a 25 percent chance that $5 million will be reallocated, and a 25 percent chance that $10 million will be reallocated. *Id*.

"[T]he Administrator has made it clear that a regional plan is pivotal to deciding how these funds would be spent and would be hesitant to agree to reallocation unless a plan were agreed upon." Tr. 721. *See also*, Lovell *et al*., WP-02-E-BPA-40, at 24. Moreover, BPA noted in rebuttal that the MOA states that ". . . the carryforward balance, and the interest credits . . . may not be reallocated to another category without the agreement of the parties in consultation with the tribes." Lovell *et al*., WP-02-E-BPA-40, at 18.

The probabilities of reallocation that BPA included "took into account . . . [BPA fish and wildlife experts'] view of the likelihood of a regional plan being developed and costs reallocated within the next year and a half." Tr. 722. BPA has not unilaterally reallocated funds between categories. The MOA does not permit it. Lovell *et al.*, WP-02-E-BPA-40, at 18. The actual expenses have been lower than predicted because fewer Congressional appropriations have been made. *Id*. at 22. Less investment has been placed in service by the COE and there is no regional plan, so BPA is unable to ensure that reallocated funds would be spent prudently and consistent with other initiatives. *Id*. at 21.

Evaluation of Positions

The MOA is the 1996 Memorandum of Agreement Concerning BPA's Financial Commitments for Columbia River Basin Fish and Wildlife Costs signed by the Secretaries of the Departments of the Army, Commerce, Energy, and Interior. The MOA obligates BPA to apply any year's underspent funds associated with fish and wildlife costs in this rate period (carryforward amounts) to fish and wildlife purposes in subsequent years. Lovell *et al.*, WP-02-E-BPA-40, at 18. The MOA also provides for a process to reallocate the carryforward balance among categories (other than "operations"). *Id*. The amounts pertaining to a category may not be reallocated to another category without the agreement of the parties in consultation with the Council and the Tribes. *Id*.

CRITFC/Yakama and NEC/SOS argue that BPA should model the possibility that the MOA carryforward balance would be reallocated before the beginning of the next rate period (FY 2002). Lothrop, WP-02-E-CR/YA-02, at 8-9; Weiss, WP-02-E-NA-01, at 19. NEC/SOS recommend that BPA include as an uncertainty the possibility that some of the carryforward balance will be reallocated. Weiss, WP-02-E-NA-01, at 19.

The risk analysis in BPA's proposal does not examine the possibility that the MOA carryforward balance would be reallocated and expended before FY 2002. Lovell *et al.*, WP-02-E-BPA-40, at 18. For calculating the final rates, however, BPA is including the uncertainty surrounding such a reallocation. As indicated in rebuttal testimony, risk distributions will be added to the NORM for FY 2000 and 2001 to determine the risk-adjusted beginning reserves for FY 2002. *Id*. at 24; Volume 1, Chapter 12, Revenue Requirement Study Documentation, WP-02-E-BPA-02A. BPA has modeled the following probabilities in NORM: a 50 percent chance that none of the carryforward balance will be reallocated, a 25 percent chance that $5 million will be reallocated, and a 25 percent chance that $10 million will be reallocated. *Id*. As mentioned earlier, the Administrator has indicated that a Regional Plan must be in place to address funding priorities before reallocation between budget categories occurs. *Id.*

CRITFC/Yakima are not satisfied with the probabilities that BPA stated it would model in the final proposal. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 39. UCUT "encourages BPA to consider the intentions of the signatories to the MOA in undertaking this modeling and adjust its estimate of starting reserves." UCUT Brief, WP-02-B-UC-01, at 22. UCUT states that "Federal parties, states and tribes are working to reallocate" the carryforward balance. *Id*. However, a reallocation must by agreed to by all the parties. Lovell *et al.*, WP-02-E-BPA-40, at 18. No such agreement has been reached.

The MOA provides a process for reallocating the carryforward balance among the non-operational categories. Lovell *et al*., WP-02-E-BPA-40, at 18. However, the BPA Administrator has indicated that a Regional Plan addressing funding priorities needs to be in place before she would favor reallocating funds among MOA budget categories. *Id*. at 24.

BPA noted during cross-examination that the probabilities and the dollar amounts used in NORM were provided by BPA fish and wildlife experts based on their professional judgment. Tr. 721-22. The probabilities take into account BPA's view of the likelihood of a regional plan being developed and costs reallocated within the next year and a half. *Id*. In addition, BPA notes in a data response that:

> BPA is hopeful that a Regional Plan will be developed through the Federal Caucus effort on the All-H paper and the NWPPC's Fish and Wildlife Program amendments. BPA anticipates that if the priorities in that plan are ready to be implemented prior to the conclusion of the MOA in 2001, and if their budgets

> exceed those in current categories, they could be considered for funding through reallocation.
>
> Most recently there has been regional discussion about the need for subbasin assessments in order to determine necessary measures and priorities for fish and wildlife recovery under the ESA and protection, mitigation and enhancement under the Northwest Power Act. BPA's estimate of a range of $5-$10 million for possible reallocation of funds between categories under the Fish and Wildlife Budget MOA is based upon an estimate of the initial costs of such an assessment effort endorsed by the Federal agencies and the states and tribes, that occurs prior to the expiration of the MOA and that exceeds the current amount budgeted for such purposes under the NWPPC's Fish and Wildlife Program budget.

Cross-Examination Exhibit, WP-02-E-NA/OP/CR/YA-02.

Finally, many carryforward costs reflect activities that have been reprogrammed into the 13 Alternatives for FY 2002-2006, and the costs of the 13 alternatives are sufficiently high. Lovell *et al*., WP-02-E-BPA-40, at 20-21. Thus, this treatment of costs should address concerns that the reserves will be inadequate should the expenses be reallocated.

To calculate the final rates, BPA modeled the probability of a carryforward balance being reallocated and spent during the remainder of the current rate period. Lovell *et al*., WP-02-E-BPA-40, at 24. Including these probabilities in NORM causes the risk-adjusted starting reserves to reflect the potential reallocation of the MOA carryforward. As CRITFC/Yakama note, reallocation of the carryforward balance reduces both the carryforward balance and beginning reserves for FY 2002-2006. Lothrop, WP-02-E-CR/YA-02, at 9. Including the probabilities in NORM will contribute to a lower risk-adjusted starting reserves estimate. *Id*.

Decision

BPA is incorporating uncertainties in its risk analysis that FY 2002 Starting Reserves may be reduced by a reallocation of part of the MOA carryforward during the current rate period. The uncertainty distribution is based on analysis and judgments by staff experts and policy judgment implemented by the Administrator. In any case, many of the carryforward costs reflect activities that have been included in the 13 Alternatives for FY 2002–2006.

Issue 4

Whether BPA appropriately used a probability distribution to capture the risk of not fully achieving $113 million in Cost Review recommendations.

Parties' Positions

PPC challenges BPA's use of a probability distribution in the NORM to capture the uncertainty of not fully achieving some of the cost reductions called for in the Cost Review recommendations. Opatrny *et al.*, WP-02-E-PP-02, at 3-4; PPC Brief, WP-02-B-PP-01, at 11. PPC recommends that BPA modify its assumptions by committing to 100 percent certainty of achieving the Cost Review Recommendations. Opatrny *et al*., WP-02-E-PP-02, at 3. PPC refers to the inclusion of probabilities surrounding cost reductions for some of the recommendations as ". . . reduction amounts that are still in doubt . . ." Opatrny *et al.*, WP-02-E-PP-02, at 3. CRITFC/Yakama support this position. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 23.

BPA's Position

As with any budget, there is not a 100 percent certainty that costs will turn out precisely as planned. If BPA were to assume 100 percent certainty of achieving the Cost Review savings, the impact would be to shift risk to Treasury, meaning that the TPP result in this rate proceeding would be overstated, if everything else remained the same. DeWolf *et al*., WP-02-E-BPA-39, at 41. The inclusion of probability distributions for certain Cost Review recommendations recognizes that the Cost Review savings recommendations are "stretch" targets with significant uncertainty and risk associated with BPA's ability to realize them. *Id*. at 40.

Evaluation of Positions

In a data request, BPA asked the PPC to explain the rationale for its position that uncertainties and risks associated with achieving the Cost Review recommendations should not be included in BPA's risk analysis. PPC responded:

> During clarification, the witnesses sponsoring WP-02-E-PP-02 stated that they were recommending that BPA assume with 100 percent certainty that the Cost Review/Issues '98 cost reductions would be achieved (except for the $18 million of cost reductions associated with recommendation #9, legislation to improve administrative effectiveness and recommendation #8, administrative and other internal services costs). This means that essentially no risk should be associated with the remaining $113 million/year of cost reductions.
>
> The panel indicated that they were not overly concerned that the cost reductions achieved were generated from the specific expense categories that make up the cost reduction package. Instead, . . . BPA should be able to, at a minimum, secure the stated level of cost reductions for the upcoming rate period. Therefore, to the extent the savings associated with particular line items identified in the Cost Review/Issues '98 processes were risky, additional cost savings would be realized from other source(s)."

DeWolf *et al*., WP-02-E-BPA-39, Attachment 6.

PPC does not provide any information about "other source(s)" that BPA should look to for additional costs savings in the event the savings associated with the items identified in the Cost Review/Issues '98 processes are not sufficient to meet the $113 million figure. DeWolf *et al*., WP-02-E-BPA-39, at 40. Absent such information, it is not prudent for BPA to assume that the $113 million cost reductions can be achieved with 100 percent probability. *Id*.

The Cost Review closely examined a wide range of FCRPS costs. The only notable exceptions to these costs were fish and wildlife recovery costs and several categories of costs that were subject to change in the Subscription Strategy and rate development process. Revenue Requirement Study, WP-02-E-BPA-02, at 12. Cost Review recommendations were made in specific areas. *Id*. The recommendations recognized that implementation of the recommendations presented significant challenges for BPA and its major power suppliers. *Id.* at 71. Moreover, many of the Cost Review panel's recommendations are "stretch goals" that involve costs over which BPA has limited influence. *Id.* In addition, the reductions recommended by the Cost Review were based upon an expense baseline that had already undergone significant cost cutting. *Id*. at 97. Given the aggressive nature of the Cost Review recommendations and the already reduced budgets to which they were to be applied, it is reasonable for BPA to include probability distributions in NORM to capture the risk and uncertainty associated with cost reductions from the Cost Review recommendations. To do otherwise would inappropriately shift risk to the Treasury. DeWolf *et al*., WP-02-E-BPA-39, at 41.

<u>Decision</u>

BPA appropriately used a probability distribution to capture the risk of not fully achieving some of the Cost Review recommendations.

<u>Issue 5</u>

Whether BPA should change its risk analysis to reflect the risk that functionalization of costs assumed functionalized to the TBL in the PBL rate case would be changed after the conclusion of the PBL rate case.

<u>Parties' Positions</u>

The IOUs state that the separation of the power and transmission rate cases makes it more difficult to ensure that costs are properly functionalized between power and transmission functions. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 77. The IOUs also do not believe that FERC should finally determine in the power rate case whether all costs functionalized to transmission are proper transmission costs until the transmission rate case is completed and submitted to FERC for approval. *Id*. at 84. Finally they argue, absent a FERC audit of BPA's accounts (based on the Uniform System of Accounts), the parties cannot determine whether costs are properly functionalized. *Id*. The IOUs recommend removing the cap on the CRAC so that any costs from the power rate case wrongly functionalized to transmission can be recovered from the power customers. *Id*. at 84-85. If the cap is not removed, the IOUs claim, then power sales contracts should contain a specific provision permitting a rate adjustment to collect any costs functionalized to transmission that FERC determines are not transmission costs. WP-02-E-AC/GE/IP/MP/PL/PS-01, at 14-15. The IOUs claim that "correctly functionalizing fiber optic expenses would result in a shift of costs from transmission rates to power rates of $25 million per year." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 66.

BPA's Position

Although BPA does not believe that the cap on CRAC should be eliminated, BPA did agree to evaluate whether the risk that potential changes in functionalization of costs would affect its risk analysis. Lovell *et al*., WP-02-E-BPA-40, at 15. After evaluating this risk, BPA has concluded that the magnitude of the risk is small and that the NORM model already captures risks related to the risk of changes to the level of PBL's transmission expense. Risk Analysis Study, WP-02-FS-BPA-03, at 23.

Evaluation of Positions

Though there is a small risk that FERC could determine some costs are incorrectly assigned to transmission and should be assigned to power, the dollar amounts are not large. Risk Analysis Study Documentation, WP-02-E-BPA-03A, at 171. The IOUs claim that correctly functionalizing fiber optic expenses would result in a shift of costs from transmission rates to power rates of $25 million per year. BPA does not know where this number came from or how it was derived. However, as discussed in ROD section 5.5, when addressing the potential costs of refunctionalizing fiber optic expenses, the IOUs have ignored the revenues to the power function that would be associated with that refunctionalization. Presently, BPA includes PNRR in its revenue requirement, which accounts for unforeseen risks. *Id*. Additionally, the NORM model already includes risks related to "probabilities of the generation function's transmission expenses deviating from the costs included in the revenue requirement." Risk Analysis Study Documentation, WP-02-E-BPA-03, at 171, 179.

In theory, additional costs could be functionalized as a result of the transmission rate proceeding, FERC action, or audit under the Uniform System of Accounts. However, the solution proposed by the IOUs--removing the cap on CRAC--represents a substantial change to CRAC design that is not based on an analysis of risks and TPP. *See* ROD section 7.3 and Issue 4, *supra*. The IOUs' solution is disproportionate to the small risk and potential impact on the power function's cost recovery. And BPA's risk mitigation strategy is sufficiently robust to adequately address the risks associated with bifurcated rate cases and the functionalization of costs between them. *See* ROD chapter 7.

Decision

BPA has reviewed the risks as it said it would in rebuttal testimony but believes that BPA's current risk analysis adequately covers the risk of refunctionalization.

6.5 Fish and Wildlife Obligations

Issue 1

Whether BPA should substitute or supplement its risk analysis with the analysis in the May 11, 1999, memorandum by regional staff of EPA, NMFS, USFWS, and Treasury.

Parties Position

CRITFC/Yakama and several other tribal sovereigns argue that BPA should incorporate the risks described in the May 11 memorandum in its risk analysis, including "the direct cost estimate of $325 million as an average over the FY 2002-2006 rate period as the most likely estimate . . ." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 55-56; CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 16-18, 23. They also urge BPA to "conduct analysis assuming direct costs could be as high as $390 million a year during the period [FY 2002-2006]." *Id. See also*, UCUT Brief, WP-02-B-UC-01, at 19-20. Finally, CRITFC/Yakama argue that BPA has ignored the May 11 memorandum and that BPA's failure to incorporate it into its risk analysis is arbitrary and capricious. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 18.

NRU argues that the May 11 memorandum represents information that is outside the scope of the rate case and not at issue in this rate case. Saven, WP-02-E-NI-05, at 25. NRU argues, "It would be totally unfair and objectionable to use the memorandum as an estimate of future fish and wildlife costs, or to argue for different program funding levels or policy choices concerning the fish and wildlife programs." *Id*. According to NRU, the May 11, 1999, memorandum is an unofficial document issued by regional fish and wildlife staff and the Treasury staff that was intended to increase fish and wildlife costs represented in BPA's rate proposal. Saven, WP-02-E-NI-05, at 25.

BPA's Position

BPA agrees with the arguments present by NRU. The use to which CRITFC/Yakama and others attempt to employ the May 11 memorandum is outside the scope of this rate proceeding. Moreover, BPA's analysis of fish and wildlife costs, based on a range of alternatives, is reasonable. *See* ROD sections 2.3 and 5.4 *infra*; DeWolf *et al*., WP-02-E-BPA-13, at 9. The BPA approach "keeps the options open." *Id*. BPA has not ignored the May 11 memorandum in its risk analysis, it has chosen to rely on a risk analysis which follows the Principles. BPA's actions meet the standard applicable to rate cases. *See* ROD section 1.4.

Evaluation of Positions

The May 11, 1999, memorandum is introduced into evidence by CRITFC/Yakama. Lothrop, WP-02-E-CR-02, Attachment 3, at 1. *See also*, DeWolf *et al*., WP-02-E-BPA-39, Attachment 1, at 1. The memorandum was authored by regional EPA, NMFS, and USFWS staffs and Treasury staff. The May 11 memorandum may be used in this rate case only to "test or challenge a party's risk analysis." Hearing Officer Order, WP-02-O-14. The memorandum purports to represent more recent estimates of BPA's direct funding requirements than estimates used by BPA in its power rate proposal. Saven, WP-02-E-NI-05, at 25. "The memorandum was developed . . . without input from the public." *Id*. "It was rushed to Washington DC before BPA's rate proposal was filed to try to convince the Administration to increase fish and wildlife costs and somehow accommodate them in the BPA rate proposal. Many customers objected when . . . [they] found out about the document . . ." *Id.* Rather than seeking to "test or challenge" BPA's risk analysis, CRITFC/Yakama merely argue that BPA adopt the contents of the memorandum. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, 29-30.

The May 11 memorandum is contradicted by the May 26, 1999, memorandum of William Stelle, head of the Seattle office of the NMFS, which states, "The timing of the rate case is out of sync with the timing of decisions regarding fish and wildlife operations through 2006. Options for those decisions are being examined currently through a number of regional processes, including the Federal Caucus. In the absence of final decisions, BPA has committed to setting its rates in a way that would not foreclose any of the options being considered." Lothrop, WP-02-E-CR-02, Attachment 4, at 2. Mr. Stelle noted that while fish and wildlife costs might be higher after 2006, it is difficult to "pin down with accuracy" the range of out-year costs. *Id*. at 3. Mr. Stelle then states, "NMFS sees no reason to conclude that BPA will not be able to cover anticipated costs." *Id*. at 3.

Mr. Stelle contradicts the May 11 memorandum's claim that BPA's draft proposal was inadequate. *See* Lothrop, WP-02-E-CR-02, Attachment 3, page 1. The May 11 memorandum fails as reliable evidence: It has not been finalized; was not authenticated; and is outside the public record exception to hearsay rules. *Federal Rules of Evidence* 801 and 803(8). The May 11 memorandum does not represent a Federal consensus, new reliable information, or a serious commitment to abide by the Principles that BPA uses as a touchstone of this rate proceeding. *See, e.g.,* section 2.3 *supra*. That is, the May 11 memorandum is neither a test nor a challenge of BPA's risk analysis.

Moreover, CRITFC/Yakama's attempt to repudiate the equal weighting of fish and wildlife alternatives embedded in the Principles was specifically rejected by Mr. Stelle's memorandum: "BPA has committed to setting its rates in a way that would not foreclose any of the options being considered." Lothrop, WP-02-E-CR-02, Attachment 4, at 2. Mr. Stelle also states, "Although it is impossible to predict with precision at this time what a fish and wildlife budget agreement through 2006 would look like, the range of costs BPA could cover with its contingent funding proposal appears adequate to cover the likely range of fish and wildlife costs through 2006." Lothrop, WP-02-E-CR-02, Attachment 4, at 3.

The May 11 memorandum is also outside the scope of the rate case. Saven, WP-02-E-NI-05, at 25. The scope of the rate case specifically excluded fish and wildlife program level discussions. 64 Fed. Reg. 4321-23. As NRU stated "[I]t would be totally unfair and objectionable to use the memorandum as an estimate of future fish and wildlife costs, or to argue for different program funding levels or policy choices concerning fish and wildlife programs." Saven, WP-02-E-NI-05, at 25.

On a more basic level, each rate case party that offers an alternative for BPA to consider in meeting its fish and wildlife obligations offers choices that conflict with other choices. BPA must balance these fish and wildlife obligations with other interests and obligations to produce its rates. This obligation is BPA's charge. 16 U.S.C. §839e(i), 94 Stat. 2726. BPA is forced by the ratesetting process and its obligations to the region to accept some positions and reject others. *See, e.g*., *Association of Public Agency Customers v. Bonneville Power Administration (APAC v. BPA),* 126 F.3d 1158, 1174-76 (9th Cir. 1997). Congress has granted BPA an unusually expansive mandate to operate with a business oriented philosophy, and the courts have found it wise to defer to actions such as these as it furthers these business interests, "especially when the agency is responding to unprecedented changes in the market resulting from deregulation." *APAC v. BPA*, at 1171. BPA's risk analysis, including its decision not to revise its risk analysis and to retain a "keep the options open" fish and wildlife strategy, reflects a reasonable approach to these changes in the industry and the Columbia River Basin. The decision not to modify BPA's risk analysis by including values and concepts presented in the May 11, 1999, memorandum was appropriate, because BPA's risk analysis keeps the fish and wildlife options open. Thus, BPA has not ignored the May 11 memorandum, it has chosen to rely on a risk analysis and risk mitigation strategy which follows the Principles in light of the obvious limitations of the May 11 memorandum

BPA's fish and wildlife risk analysis and risk mitigation, including its treatment of the May 11 memorandum, is supported by substantial evidence and is not arbitrary and capricious. *See* ROD section 1.4, *supra*.

<u>Decision</u>

BPA made appropriate judgments when it did not revise its risk analysis to reflect the information and concepts contained in the May 11, 1999, memorandum.

6.6 <u>Risk and Environmental Obligations</u>

<u>Issue</u>

Whether BPA's risk analysis adequately considers the uncertainty in BPA's fish and wildlife obligations under applicable environmental laws.

<u>Parties' Positions</u>

CRITFC/Yakama argue that the BPA risk analysis for the FY 2002-2006 rate period does not adequately address uncertainty in fish and wildlife obligations imposed upon BPA by the CWA. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 11-13; CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 23. They note that the EPA found that dams commonly exceed water quality standards for temperature and total dissolved gases. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 12.

CRITFC/Yakama also argue that the BPA risk analysis for the FY 2002-2006 rate period does not adequately address uncertainty in fish and wildlife obligations imposed upon BPA by the ESA (16 U.S.C. §1531-1543). CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 13-15; CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 23.

CRITFC/Yakama further argue that the BPA risk analysis for the FY 2002-2006 rate period does not adequately address uncertainty in fish and wildlife obligations imposed upon BPA by the F&WCA. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 15-17; CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 23.

CRITFC/Yakama also argue that potential Northwest Power Act obligations should be included in BPA's risk analysis. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 17-18; CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 23.

BPA's Position

BPA disagrees with CRITFC/Yakama's assertion that BPA's risk analysis does not adequately address BPA's obligations under certain Federal and environmental laws because BPA assumed a low probability for fish and wildlife alternatives that CRITFC/Yakama allege are most likely to comply with applicable laws. The 13 Fish and Wildlife Alternatives established in the Principles development process represent, in the Clinton Administration's judgment and based on extensive regional input, a reasonable range within which the costs of eventual decisions on system reconfiguration and related operations can be expected to fall. DeWolf *et al*., WP-02-E-BPA-13, at 9. The Principles are intended to "keep the options open" for future decisions by: (1) specifying that each of the 13 Fish and Wildlife Alternatives should be treated by BPA as equally likely to occur; and (2) establishing a high cost-recovery goal, expressed as an 88 percent/five-year TPP goal. *Id*. Thus, the 13 Fish and Wildlife Alternatives represent a set of assumptions, a forecasting convention, to establish capital investment and O&M levels, system operations assumptions, and risk analysis assumptions for purposes of setting rates. *Id*.

Evaluation of Positions

CRITFC/Yakama argue that potential CWA (13 U.S.C. §1313) obligations should be included in BPA's risk analysis. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 11-13. They cite water quality standards for maximum water temperature and the total dissolved gas standards as examples of those obligations. *Id*. at 12. CRITFC/Yakama argue that BPA's analytical approach for addressing fish and wildlife costs is inconsistent with the CWA. *Id*. at 13.

CRITFC/Yakama also argue that potential ESA obligations should be included in BPA's risk analysis. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 13-15. They cite the decline of Columbia River and Snake River threatened and endangered salmon stocks and most unlisted stocks as examples of those obligations. *Id*. at 13. CRITFC/Yakama argue that BPA's analytical approach for addressing fish and wildlife costs is inconsistent with the ESA, and that assumptions tend to underestimate the probabilities that BPA will be exposed to higher fish and wildlife costs than considered in the Bonneville testimony. *Id*. at 14. CRITFC/Yakama cite PATH (the Plan for Analyzing and Testing Hypothesis) biological analysis that suggests that lower cost alternatives would not likely meet ESA recovery. *Id*.

CRITFC/Yakama further argue that potential F&WCA obligations should be included in BPA's risk analysis. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 15-17. They argue that the F&WCA requires Federal agencies to give "full consideration" to fish and wildlife managers, but concede that the final decision rests with the Federal agency. *Id.* at 15-16. CRITFC/Yakama cite drawdown and breaching alternatives identified in a December 1999 USFWS Coordination Act Report, and argue that BPA had access to a copy of the draft report in the Summer of 1999 and should have given more weight to these alternatives and less weight to others. *Id*. at 16.

CRITFC/Yakama assert that BPA has not adequately funded the Columbia River Basin Fish and Wildlife Program. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 18. CRITFC/Yakama argue that BPA's analytical approach for addressing fish and wildlife costs is inconsistent with the Northwest Power Act. *Id*.

BPA has followed the Principles and produced a reasonable range of alternatives designed to "keep the options open" for future decisions. DeWolf *et al*., WP-02-E-BPA-13, at 7-9. The risk analysis is an analysis of financial impacts, including the probability that BPA's payments to Treasury will be made in full and on time. Risk Analysis Study, WP-02-E-BPA-03, at 1-2. BPA included the full range of potential fish and wildlife costs in a manner consistent with the Principles. *Id*. at 3. These costs consist of operational impact costs, expenses, capital costs, and BPA direct program O&M. *Id*. BPA modeled the operational impact costs in RiskMod and the expenses, capital costs, and BPA direct program O&M in NORM. *Id*. Consistent with the Principles, BPA direct program O&M was modeled in NORM to range from $100 million to $179 million. Also as specified in the Principles, BPA treated each of the 13 Fish and Wildlife Alternatives as equally likely to occur. *Id*.

The Risk Analysis Study explores the hydrosystem operation implications and net revenue impacts for each of the 13 Fish and Wildlife Alternatives. Risk Analysis Study, WP-02-E-BPA-03, at 3. These 13 Fish and Wildlife Alternatives include five Fish and Wildlife Alternatives that involve the breaching of dams. *Id*. These five Alternatives include both adjusted and unadjusted schedule variants, for a total of 18 fish and wildlife scenarios. *Id*. For a more complete discussion of BPA's fish and wildlife obligations under the CWA, ESA, Fish and Wildlife Coordination Act, and the Northwest Power Act, *see, supra*, section 5.3.2, Issue 1.

<u>Decision</u>

BPA's risk analysis adequately considers the uncertainty in BPA's fish and wildlife obligations under applicable environmental laws.

6.7 <u>Legal and Procedural Issues</u>

<u>Issue 1</u>

Whether the Risk Analysis is deficient because it is either not supported by substantial evidence or otherwise is not well-reasoned.

<u>Parties' Positions</u>

Alcoa/Vanalco argue that the Administrator should strike the testimony of the risk analysis panel and recommence the rate case. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 54. Alcoa/Vanalco argue that the Risk Analysis does not reflect independent judgment. *Id*. at 44-47.

Finally, Alcoa/Vanalco argue that due process is violated. *Id*. at 47. The Joint DSIs also argue that when BPA holds them accountable for their failure to follow the rate case procedures, BPA is acting arbitrary and capricious and contrary to law. DSI Ex. Brief, WP-02-R-DS-01, at 13-16.

UCUT argues that BPA used no objective criteria to assess its fish and wildlife costs and did not rely on expertise in fish and wildlife agencies. UCUT Brief, WP-02-B-UC-01, at 19. This appears to be an argument that BPA's treatment of fish and wildlife costs was arbitrary and capricious. *Id*. CRITFC/Yakama argue similarly. CRITFC/Yakama Brief, WP-02-B-CR\YA-01, at 2; s*ee also*, CRITFC/Yakama Ex. Brief, WP-02-R-CRYA-01, at 23. The Shoshone-Bannock Tribes generally support the UCUT and CRITFC/Yakama arguments. Shoshone-Bannock Brief, WP-02-B-SH-01, at 3.

NEC/SOS argue that the risks BPA has analyzed are inadequate: "Faced with such uncertainty, BPA must do more planning, and more statistical analysis than ever--and develop a rate structure with more flexibility so as to react to the uncertainty." NEC/SOS Brief, WP-02-B-NA/SA-01, at 16-23. They argue that BPA's failure to accept the NEC/SOS proposal, among other things, "is unwarranted, arbitrary and capricious." *Id*. at 23.

BPA's Position

BPA's proposal includes a policy choice to consider within BPA's risk analysis "the full range of potential fish and wildlife costs represented by the 13 alternatives by assuming that each alternative is equally likely to occur." Burns and Elizalde, WP-02-E-BPA-08, at 5. Moreover, the risk analysis studies two kinds of risks, operating risks and non-operating risks. Risk Analysis Study, WP-02-E-BPA-03, at 2. Policy issues were addressed elsewhere in the rate case. Burns and Elizalde, WP-02-E-BPA-08, at 5. Finally, the arguments are waived, since the arguments are not timely or are not adequately presented.

Evaluation of Positions

Alcoa/Vanalco argue that the risk panel did not exercise independent judgment, so the panel's analysis and conclusions are invalid. In particular, Alcoa/Vanalco argued:

> Thus the professionals retained by BPA to assess its risk did not do so because instead they followed a directive from the Clinton Administration, specifically, the Fish and Wildlife Principles process spearheaded by Vice President Gore. Tr. 586, lines 25-587, at 1. Under the APA, the Administrator's decision must be upon the record developed by the decisionmaker at the time the decision was made--not on some evidence outside the record … There was no independent judgment exercised by BPA. Instead, the collective judgment of a variety of parties in and outside the process was used as a substitute for valid expert opinion on these subjects.

Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 45.

The rate case presents a fair and balanced evaluation of risk and its impacts on BPA during the FY 2002-2006 rate period. Risk Analysis Study, WP-02-E-BPA-03, at 2-4. The panel's treatment of the fish and wildlife issues is limited in scope. *See e.g.,* Burns and Elizalde, WP-02-E-BPA-08, at 4-5. These policy choices, including treatment of fish and wildlife issues, are discussed principally in section 5.4 of this ROD. BPA's risk analysis integrates numerous analytical tools and evaluates both operating risks and non-operating risks. *See, generally*, Risk Analysis Study, WP-02-E-BPA-03. BPA's analysis implemented the Fish and Wildlife Funding Principles developed in an extensive public process. 64 Fed. Reg. at 44321-23; ROD section 2.3. BPA's risk analysis addresses the most substantial uncertainties to confront the agency, in the form of operational constraints and potential obligations for protecting the region's fish and wildlife resources. Risk Analysis Study, WP-02-E-BPA-03, at 8-11.

BPA's risk analysis generally used models and results available to rate case parties for their own analysis. BPA made prudent changes in its risk analysis from the analysis employed in the most recent general rate case (1996) to make its analysis more reliable. Conger *et al.*, WP-02-E-BPA-15, at 2-15. BPA applied scientific rigor in analyzing the information in the models it used to produce the analysis. *Id*. BPA calibrated and adjusted its models to more accurately analyze current and future risks. *Id*. at 6-12. BPA documented its analysis. Risk Analysis Study Documentation, WP-02-E-BPA-03A. The parties' arguments are without merit.

Alcoa/Vanalco argue that BPA has violated *Daubert v. Merrel Dow Pharmaceutical, Inc.*, 509 U.S.579, 125 L.Ed. 2d.469, 113 S. Ct. 2786 (1993), the seminal case on the admission of expert testimony and the obligation of the fact finder to evaluate the admissibility of testimony. In essence a judge is responsible for the testimony of a witness resting on a reliable foundation and that the testimony is relevant. *Applying Daubert and Joiner to Scientific Evidence by Linking Legal and Scientific Reasoning*, 13 Toxics Law Reporter 338 (1998). The appropriate time for raising this argument would have been in a motion to strike, because it challenges the qualifications of BPA witnesses and the validity of the testimony and exhibits they presented at the hearing. *Procedures* at §1010.11(d). Even cross-examination would have provided an opportunity to test both the qualifications and validity of evidence. Instead, Alcoa/Vanalco deprived BPA and the other parties of an opportunity to meet the accusation with evidence, and deprived the Hearing Officer of the opportunity to rule on the issue initially. Alcoa/Vanalco have waived the argument. *Id*. at §1010.13(b) and (c).

As part of this ratesetting process, the agency and panel were faced with many choices reflecting which business risks to model and how to fairly and scientifically model the risks so as to enable a power rate case proposal and a final rate to successfully survive review by FERC and the appellate courts. The choices produced evidence reflected in the Risk Analysis Study, WP-02-E-BPA-03, and the Risk Analysis Study Documentation, WP-02-E-BPA-03A, as well as testimony of witnesses, Conger *et al*., WP-02-E-BPA-15, and Conger *et al*., WP-02-E-BPA-41, and cross-examination of the panel by rate case parties, Tr. 735- 825 and Tr. 1902-1949.

Alcoa/Vanalco plainly violate the rules of the proceeding by arguing that the rate analysis panel should be struck or disregarded by the Administrator, because "BPA's failure to conduct its risk analysis consistently with known risk variables calls into question the entire validity of the study and testimony of its risk analysis experts under *Daubert*." Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 34.

The rules of the proceeding describe when such arguments are appropriate. *Procedures*, §1010.11(d), §1010.13. In this way, BPA and the participants can be assured that there is an opportunity for the parties to respond and contribute to the proceedings. This is a transparent attempt by some parties to circumvent rules intended to ensure a fair and efficient establishment of BPA rates. Motions to strike prefiled testimony and exhibits must be filed within seven days after service. *Procedures*, §1010.11(e). The motion was not timely.

Qualifications of the risk panel members--Conger, WP-02-Q-BPA-14; Steele, WP-02-Q-BPA-64; Lovell, WP-02-Q-BPA-44; Wagner, WP-02-Q-BPA-67; Bleifuss, WP-02-Q-BPA-04; Petty, WP-02-Q-BPA-58; Thor, WP-02-Q-BPA-66; and Lamb, WP-02-Q-BPA-40--were made available for all parties to review contemporaneous with BPA's proposal. No party moved to strike or objected to the admission qualifications of the Risk Panel members. *See* Tr. 1948. Moreover, the parties had two opportunities to question the qualifications of risk panel members and did so in a brief examination of Dr. Lovell's substantial expertise in the area of risk analysis. This effort did not lead to objections to the risk panel's testimony on the basis of their qualifications. *Daubert's* standard has been met.

<u>Decision</u>

BPA's risk analysis panel's testimony and exhibits are valid and did not violate any standard for the sufficiency and admissibility of evidence or due process.

7.0 RISK MITIGATION

7.1 Introduction

Because the environment within which BPA operates is filled with numerous uncertainties, the ratesetting process must take into account a wide spectrum of risks. This is carried out in two distinct steps: a risk analysis step, in which the distributions or profiles of operating and non-operating risks are defined, and a risk mitigation step, in which different measures are tested to assess BPA's ability to recover its costs in the face of this uncertainty. RiskMod and NORM (the Non-Operating Risk Model) are used in the risk analysis step for the 2002 rates, while the ToolKit model is used to test risk mitigation options. Revenue Requirement Study Documentation, Volume 1, WP-02-E-BPA-02A, at 275, 279-280.

By law, BPA's payments to Treasury are the lowest priority of revenue application, meaning that principal, interest, and other payments to Treasury are the first to be missed if financial reserves are insufficient to pay all bills on time. For this reason, BPA measures its potential for recovering costs in terms of probability of being able to make Treasury payments on time.

In the 1993 rate filing, BPA established a long-term policy for meeting its obligations for repaying the U.S. Treasury. 1993 ROD, WP-93-A-02, at 68-72. At that time, two repayment probability calculations were made that have been referenced in rate cases since that time, one short-term and one longer-term. In 1993, a short-term goal was set to ensure a 95 percent probability of making both of the annual payments in the two-year rate period on time and in full. *Id.* A longer-term result, sought in the 10-Year Financial Plan, was to maintain that 95 percent rate period standard for five consecutive two-year rate periods. *Id.*

This TPP standard was established as a rate period standard: that is, it focuses upon the percentage of time BPA successfully makes all of its payments to Treasury over the entire rate period rather than setting numerical goals for year-to-year performance. *Id.* at 70.

In the 1996 rate filing, the length of the rate period changed from two to five years, and the TPP was converted to a value consistent with a longer rate period. Arnold *et al.*, WP-96-E-BPA-15, at 3-4. This value is 88 percent. *Id.* The Principles set this 88 percent, five-year standard as the Treasury repayment goal for the 2002 rate case, with an allowable range down to 80 percent. Revenue Requirement Study Documentation, Volume 1, WP-02-E-BPA-02A, at 355.

Although the Risk Mitigation Methodology for the 2002 rate case displayed many similarities with previous rate cases, it also contained a number of new features.

- There were a larger number and wider variety of risks considered in setting rates. In addition to the operating risks that had been analyzed and modeled in prior rate cases, and remain the greatest source of risk in the 2002 rate case, this rate proposal also considered the impacts of policy-related nonoperating risks.

- There were revised guidelines for both rate design and risk mitigation. These included:
  - Fish and Wildlife Funding Principles (including the goal of strict adherence to the 88 percent TPP standard in full);
  - A pledge by BPA to its customers to keep power rates both stable and at levels equivalent to those established for the current rate period; and
  - The inclusion of both a CRAC and a Dividend Distribution Clause (DDC) in the rate design to deal with potential revenue shortfall and overrecovery.

Revenue Requirement Study Documentation, Volume 1, WP-02-E-BPA-02A, at 275-307.

BPA uses the ToolKit model to test the effectiveness of various risk mitigation measures as part of a rate package that meets the 88 percent TPP goal while meeting BPA's rate pledge to its customers. These risk mitigation measures include starting financial reserves, CRAC, and PNRR. Both section 4(h)(10)(C) credits and the Fish Cost Contingency Fund (FCCF) are modeled in RiskMod and are part of the net revenue deviations used as inputs to ToolKit. *Id.* at 278.

Three hundred distinct values for starting reserves for the FY 2002-FY 2006 period were projected from FY 1999 estimates using a current rate period ToolKit model. *Id.* at 283. This version of ToolKit used net revenue deviations developed for the 1996 rate proposal using the Short Term Risk Evaluation and Analysis Model (STREAM). *Id.* The average starting reserves value for FY 2002 used in the final proposal is $842.3 million. Revenue Requirement Study Documentation, Volume 1, WP-02-FS-BPA-02A, at 272.

- CRAC is an automatic temporary upward adjustment to posted power prices if Actual Accumulated Net Revenues (AANR) fall below a threshold level. Revenue Requirement Study Documentation, Volume 1, WP-02-E-BPA-02A, at 277. Because ToolKit calculates cash flows, CRAC thresholds and annual caps were modeled based on reserves. *Id.* at 283-284. For the rate proposal, reserves thresholds were set at $300 million in 2001 and 2002 and $500 million in 2003-2005, and annual caps were set at $125 million if the threshold is crossed in 2001, $135 million in FY 2002, $150 million in FY 2003, $150 million in FY 2004, and $87.5 million in FY 2005. Lovell *et al.*, WP-02-E-BPA-14, at 6-9.

- PNRR is a component of the revenue requirement added to expenses to increase cash flows for risk mitigation purposes. Revenue Requirement Study Documentation, Volume 1, WP-02-E-BPA-02A, at 267. For the final proposal, a PNRR of $98 million was needed to produce an 88 percent TPP. Revenue Requirement Study Documentation, Volume 1, WP-02-FS-BPA-02A, at 276.

- The FCCF is comprised of 4(h)(10)(C) credits that BPA earned since the enactment of the Northwest Power Act in 1980 and prior to 1995, when BPA began taking these credits annually. Revenue Requirement Study Documentation, Volume 1, WP-02-E-BPA-02A, at 287. The $325.2 million in this fund is designed to provide protection against certain

> operating risks associated with the use of the hydrosystem, and can be accessed when the impacts of court-ordered changes to hydro operations, adverse water conditions, or natural disasters exceed certain established thresholds. *Id.* The impact of FCCF credits on net revenues is modeled in RiskMod. *Id.*

The wide bandwidth of uncertainty BPA considered in formulating its 2002 rates is illustrated in four figures included in BPA's direct testimony on risk mitigation. Lovell *et al.*, WP-02-E-BPA-14, Attachment 2. These graphics show how the ToolKit Model is used in testing the effectiveness of risk mitigation strategies and determining the amount of PNRR needed to meet the 88 percent TPP standard.

The methodology employed in the ToolKit modeling is consistent with an emphasis on full rate period success in recovering all costs, including lowest priority Treasury payments. Revenue Requirement Study Documentation, Volume 1, WP-02-E-BPA-02A, at 275-307. While ToolKit calculates sequential year-end financial reserve balances for a number of alternative simulations of the rate period under different risk profiles (or games), it counts games (or full rate periods) in calculating TPP percentages. *Id.* at 282. For the rate proposal, an 88 percent TPP meant that in 3432 (.88*3,900 = 3,432) of the 3,900 games modeled by ToolKit, no misses ("deferrals") occurred--that is, ending reserves never fell to $50 million (or less) in any of the five years in the rate period. *Id.* Payments were made on time and in full five years in a row. *Id.*

7.2 Probability of Repaying Treasury

Issue 1

Whether the TPP goal, design of risk mitigation tools, and design of DDC violate subsection 7(n) of the Northwest Power Act, which declares that rates shall recover costs for protection, mitigation, and enhancement of fish and wildlife, not to exceed such amounts forecasted to be expended during the FY 2002-2006 rate period, while preserving the Administrator's ability to establish appropriate reserves and maintain a high TPP for the subsequent rate period.

Parties' Positions

NRU argues that the DDC, unlike their proposal for a reverse CRAC, potentially shifts costs of the post-2006 era to current customers. Saven, WP-02-E-NI-01, at 16.

The DSIs contend that "(g)roups who seek more expensive risk mitigation packages are seeking . . . to misuse BPA's rates to build a war chest for dam removal." DSI Brief, WP-02-B-DS-01, at 48-51. They state that BPA staff has confirmed that the risk mitigation package could be used to build a "war chest" for dam removal. DSI Ex. Brief, WP-02-R-DS-01, at 2-48. The DSIs claim that BPA's proposal for an 88 percent TPP goal "is precisely what Congress intended to prevent" when it enacted subsection 7(n) of the Northwest Power Act. *Id.* Subsection 7(n) "was adopted expressly to address widespread concerns that BPA was proposing an overly-expansive approach to risk mitigation in this case which would create a "slush fund" for dam removal." *Id.* "Section 7(n) was passed expressly to prevent BPA from overcharging its customers by collecting funds in excess of a reasonable forecast of funds that would actually be expended on fish and wildlife costs" in the 2002-2006 rate period. DSI Ex. Brief, WP-02-R-DS-01, at 17. Congress considered, but rejected, an earlier draft of 7(n) that would have endorsed the Principles. *Id*.; DSI Brief, WP-02-B-DS-01, at 48-51. Principle No. 3 suggests that BPA may set a TPP anywhere from 80-88 percent. However, Congress, legislating with full knowledge that BPA has previously set rates to achieve an 80 percent level of TPP, rejected the idea that an increase in TPP is required. *Id*.; *see also* DSI Ex. Brief, WP-02-R-DS-01, at 2-51. Specifically, 7(n) requires BPA to maintain, not increase, the TPP in this rate period. *Id*. "The very act of seeking hundreds of millions of dollars annually to mitigate the "policy risk" of higher fish and wildlife costs *beyond the amounts forecast* to be spent in the rate period is a direct violation of section 7(n)." DSI Ex. Brief, WP-20-R-DS-01, at 17.

The DSIs contend that the DDC mechanism, with its five-year, forward-looking Treasury payment probability test, amounts to setting rates to recover fish costs that would be expended after the rate period--and that this violates subsection 7(n). *Id*. at 2-52. The DDC allows the Administrator to reduce the amount of distributions taking into consideration post-2006 costs and risks. This " . . . amounts to setting rates to recover fish costs to be expended after the rate period--precisely what is forbidden by subsection 7(n)." *Id*.

On the other hand, NEC/SOS state that "BPA has left out an important statutory standard in its listing of the statutory guidelines governing this rate case . . ." NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 4. NEC/SOS assert that:

> BPA has omitted the extremely important and relevant standard contained in the recently passed section 7(n) of the Northwest Power Act, which reads, in part:
>
> > . . . rates established by the Administrator . . . shall recover costs for protection, mitigation and enhancement of fish and wildlife . . . *while preserving the Administrator's ability to establish appropriate reserves and maintain a high Treasury payment probability for the subsequent rate period*.

Id. (emphasis added).

NEC/SOS argue that BPA's statement that the risk mitigation tools that BPA is proposing are all designed to mitigate risks modeled for FY 2002-2006 only is "not sufficient and does not meet the legal standard of Section 7(n) of the Act. *Id*. Further, NEC/SOS assert that "[f]ailure to recognize this statutory standard has lead [sic] BPA to create a rate which may adequately recover costs for the 2002-6 period but utterly fails to position the agency adequately for the subsequent rate period. *Id*.

CRITFC/Yakama state that it is common practice for a business to position itself to address future risk by creating reserves necessary to accommodate that future risk. Sheets, WP-02-E-CR/YA-05, at 10.

CRITFC/Yakama incorporate by reference the arguments set forth by the NEC/SOS concerning section 7(n) of the Northwest Power Act. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 24.

BPA's Position

BPA's rates are being set to recover costs for the FY 2002-2006 period. BPA is adopting a mechanism to rebate or otherwise distribute revenue generated by these rates to the extent reserves grow to levels that are beyond what is needed to recover cost over the ensuing five years. Such distributions would occur in FY 2002-2006 using reserves generated by rates and cost in FY 2002-2006. These actions do not shift any future, post-2006 costs into the FY 2002-2006 period, or in any way cause BPA's rates to recover expenses for fish and wildlife above the level forecast by the Administrator for the FY 2002-2006 period. Post-2006 costs do not affect the level of rates in this proposal. DeWolf *et al*., WP-02-E-BPA-39, at 20.

Evaluation of Positions

Subsection 7(n) of the Northwest Power Act reads:

> Limiting the Inclusion of Costs or Protection of, Mitigation of Damage to, and Enhancement of Fish and Wildlife, Within Rates Charged by the Bonneville Power Administration, to the Rate Period in which the Costs are Incurred.
>
> Notwithstanding any other provision of this section, rates established by the Administrator under this section shall recover costs for protection, mitigation and enhancement of fish and wildlife, whether under the Pacific Northwest Electric Power Planning and Conservation Act or any other Act, not to exceed such amounts the Administrator forecasts will be expended during the fiscal year 2002-2006 rate period, while preserving the Administrator's ability to establish appropriate reserves and maintain a high Treasury payment probability for the subsequent rate period.

See 2000 Energy and Water Development Appropriations Act, HR 2605 ENR, P.L. 106-60.

Subsection 7(n) refers to BPA ratesetting for FY 2002-2006. BPA is instructed to set rates at levels sufficient, and no higher than sufficient, to recover authorized costs of protecting, mitigating, and enhancing fish and wildlife that are forecasted to occur during the same five-year period. This includes a deterministic forecast of fish and wildlife expenses in revenue requirements and the repayment schedule for FY 2002-2006. This also includes the costs of mitigating risks in FY 2002-2006 to ensure with a high level of confidence that such costs will be recovered timely. Subsection 7(n) goes on to preserve the Administrator's flexibility to build and maintain financial reserves to position BPA to achieve a comparably high confidence level for recovering costs post-2006, consistent with Principle No. 4.

Costs in repayment studies and in revenue requirements reflect an average of the costs of the 13 Alternatives for the five years in the instant rate period only. DeWolf *et al*., WP-02-E-BPA-13, at 7-10. *See, also,* Revenue Requirement Study Documentation, WP-02-FS-BPA-02A, Chapter 13, section II, and DeWolf *et al*., WP-02-E-BPA-39, at 26-28. BPA is not pulling costs from FY 2007 or future years into the 2002-2006 rate period repayment studies and revenue requirements. *Id.* Flexibility to reduce a distribution because the cash may be needed to pay the bills later on does not constitute pulling costs into the 2002-2006 period. The DSIs present no evidence or logic to support their contention that the DDC "amounts to setting rates to recover fish costs to be expended after the rate period." DSI Brief, WP-02-B-DS-01, at 52. Rates for 2002-2006 are being set *now,* in *this* rate proposal, and *not* when the DDC is being implemented. That said, if there were any impact on rates, it would be to smooth or reduce post-2006 rates. By the same token, BPA is not adding to revenue requirements an unexpended balance or "carryforward" that has accumulated in FY 1996-2001 under terms of the current interagency MOA for fish and wildlife recovery. Lovell *et al*., WP-02-E-BPA-40, at 19. *See* MOA carryforward issues, *infra*.

BPA is modeling risks in RiskMod and NORM for the FY 2002-2006 period only. Risk Analysis Study, WP-02-E-BPA-03, at 1, 9, 10, 14-17, and 19-23. *See also*, Risk Analysis Study Documentation, WP-02-E-BPA-03A. The 2002 power rates evaluated in this proceeding will cover the FY 2002-2006 period revenue requirement only. The TPP goal for which risk mitigation tools have been designed applies to FY 2002-2006 only. DeWolf *et al*., WP-02-E-BPA-13, at 21-27.

The risk mitigation tools that BPA designed for the 2002 rates are applicable and effective in FY 2002-2006 only. They are all designed to mitigate risks modeled for FY 2002-2006 only. In particular, the starting reserves tool represents all projected cash in the BPA fund attributable to power as of the beginning of FY 2002. The full amount of these reserves is made available to mitigate risk during the instant rate period. In addition, the CRAC is allowed to trigger and raise rates in rate period years based on conditions prevailing in only the rate period years. Further, planned net revenues for risk are added to expenses in each rate period year only. And finally, FCCF credits are modeled statistically based on water conditions in rate period years only. Revenue Requirement Study Documentation, Volume 1, WP-02-E-BPA-02A, Chapter 12.

The DDC is a mechanism that is applicable to and effective in FY 2002-2006 only. The threshold of the DDC is a threshold based on actual net revenues accumulated through FY 2002-2006 only. Distributions would occur in FY 2002-2006 only. If the threshold is met, the Administrator would reduce the amount that is distributed if, and only to the extent that, amounts above the threshold were needed to meet the TPP goal. The Administrator's determination would be based on a financial forecast and risk analysis for the ensuing five-year period. This means that dividends could be reduced to as low as zero even if the threshold were exceeded, if that cash was deemed necessary to ensure that future costs would be recovered with a high degree of certainty. DeWolf *et al*., WP-02-E-BPA-39, at 13. The Administrator would render that judgment, but only after a public airing of the forecast and risk analysis and after ample opportunity for public comment each time the DDC thresholds were crossed. In BPA's judgment, it makes no business sense to be rebating cash today if tomorrow it will be needed. *Id.* at 15.

The DSIs state that subsection 7(n) was passed by Congress ". . . expressly to address widespread concerns that BPA was proposing an overly-expansive approach to risk mitigation in this case which would create a "slush fund" for dam removal." DSI Brief, WP-02-B-DS-01, at 48-51. Such widespread concerns, if ever true as described, are now alleviated by BPA's rate proposal: the approach to risk mitigation is fundamentally a product of public involvement processes, including the 10-Year Financial Plan/TPP standard, Fish and Wildlife Funding Principles, and Subscription Strategy public processes. BPA is setting up no "slush fund" or "war chest" or anything like it for dam removal, and the transcript that the DSIs cite is certainly not the confirmation they pretend. DSI Ex. Brief, WP-02-R-DS-01, at 2-48 to 2-49. Indeed, the Principles that BPA is implementing in the 2002 rates are driven by a "keep the options open" strategy that explicitly treats each salmon recovery alternative as equally likely to occur. No preference or weight is given to low-cost alternatives over high-cost alternatives, or vice versa. DeWolf *et al*., WP-02-E-BPA-13, at 7-21. BPA's rate pledge is being met. And BPA's DDC is designed to reduce reserves to the extent they accumulate to levels higher than are demonstrably needed to ensure near- and mid-term recovery of costs.

The DSIs' contention that 7(n) somehow requires BPA to reduce its cost recovery goal is without foundation. Nothing on the Congressional record suggests that Congress intended BPA to implement an 80 percent TPP goal rather than the 88 percent goal BPA proposed in this proceeding. The 88 percent TPP standard is a long-standing policy goal. DeWolf *et al*., WP-02-E-BPA-13, at 22-23; 1993 ROD, WP-93-A-02, at 68-72. *See* Issue 2, *infra*. The DSIs err in stating that subsection 7(n) requires that BPA maintain, not increase, the TPP in *this* rate period. Rather, as quoted above, subsection 7(n) preserves the Administrator's ability to establish reserves and maintain a high Treasury payment probability for the *subsequent* rate period, meaning the period after FY 2002-2006.

The DSIs contend that the DDC mechanism, with its five-year, forward-looking Treasury payment probability requirement, amounts to setting rates to recover fish costs that would be expended after the rate period. DSI Brief, WP-02-B-DS-01, at 52. The DSIs claim that since "BPA is proposing to exercise discretion to invoke the DDC mechanism depending upon expected post-2006 costs," it is essentially setting rates to recover post-2006 fish costs. *Id*. The DSIs are incorrect. The DDC is not a rate as the DSIs suggest, but a mechanism designed to ensure that reserves are constrained by means of rebates or other means to levels demonstrably needed to recover costs. In BPA's view, the DDC design is precisely what Congress intended in subsection 7(n) when it preserved the Administrator's ability to ". . . establish appropriate reserves and maintain a high Treasury payment probability for the subsequent rate period."

Decision

BPA's 2002 power rates comply in full with the recently passed subsection 7(n).

Issue 2

Whether BPA should implement a TPP goal of 88 percent for the five-year rate period.

Parties' Positions

Several customer parties argue that BPA should target a lower TPP than the 88 percent TPP goal in the rate proposal.

Alcoa, Vanalco, and Energy Services support reducing the TPP goal by arguing that BPA will not be assuming more risks by lowering the TPP goal. Speer *et al*., WP-02-E-AL/VN/EG-02, at 10. Alcoa/Vanalco contend that BPA does not have a historical precedent for the 88 percent goal, since 80 percent is the highest TPP that BPA has implemented in rates for a five-year rate period. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 22. They also conclude that the 10-Year Financial Plan that BPA adopted in 1993, which outlines BPA's current TPP policy, officially expires in 2003 and that it is not legally applicable (enforceable) post-2003. *Id*. at 23; Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 35.

The DSIs argue that BPA should reduce its TPP goal to 80 percent, reduce PNRR to zero, and make CRAC sufficiently robust to meet the lower TPP level. DSI Brief, WP-02-B-DS-01, at 47-49. The DSIs contend that an increase from the historical level of 80 percent to 88 percent comes at too high a cost to customers. *Id*. The DSIs claim that BPA fails to account for reductions in risk arising from Slice sales and other factors; if these reductions in risk were accounted for, the TPP result would be considerably higher than the 88 percent that BPA says. *Id*. They also argue that the Principles do not require BPA to implement an 88 percent TPP, and BPA fails to support or justify its assertion that Principle No. 4 may be undermined if a lower TPP were adopted. *Id*. at 48-51. They argue that BPA's decision to implement an 88 percent TPP for the rate period is arbitrary, capricious, and contrary to law. DSI Ex. Brief, WP-02-R-DS-01, at 18.

PPC, without specifying a TPP goal, asserts that BPA's risks are adequately mitigated with a TPP less than 100 percent but greater than the maximum of 80 percent advocated by various DSIs. PPC Brief, WP-02-B-PP-01, at 17.

The IOUs argue that BPA should implement an 88 percent TPP or higher goal, correct some modeling flaws, and redesign the CRAC to further ensure that risks are borne by power customers. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 55-59. The IOUs contend that BPA's TPP goal and risk mitigation proposal "fails to align the risks and benefits of federal power," which results in lower benefits to residential and rural customers. *Id.* The IOUs state that the 88 percent TPP goal means that power rates will generate sufficient revenues to meet BPA's financial goals 88 percent of the time and that there is a 12 percent probability/risk that BPA will rely on a transmission surcharge to ensure that power costs are recovered timely. *Id.*

The IOUs have limited access to BPA's low-cost power and therefore purchase from higher-cost sources. BPA has capped the CRAC at levels below market price expectations, and in the event of a shortfall in power revenues, BPA would necessarily levy a surcharge on transmission rates. Thus, the IOUs claim, because they would be subject to a transmission surcharge, they would be put in the position of subsidizing other BPA customers who are entitled to large amounts of Federal power at below-market prices. *Id.* The IOUs state that BPA should redesign CRAC to enable BPA to increase power rates up to market prices before resorting to a transmission surcharge. *Id.*

NEC/SOS and CRITFC/Yakama support full implementation of the TPP standard. However, they argue that BPA's proposal variously underestimates risks, misinterprets and misapplies the standard, and otherwise fails to mitigate risks adequately, thus causing the proposal to come up short of full implementation. NEC/SOS Brief, WP-02-B-NA/SA-01; CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 40-44. UCUT urges BPA to consider increasing TPP to 100 percent for only the year 2006, to help ensure financial readiness for costs in the next rate period. UCUT Brief, WP-02-B-UC-01, at 26.

BPA's Position

BPA is implementing the Principles in the 2002 rates. The Principles call for 88 percent as the five-year TPP goal, but allow a TPP as low as 80 percent. BPA is implementing the 88 percent TPP goal in order to meet a long-standing TPP policy standard and to fully meet Principles No. 3 and No. 4. DeWolf *et al*., WP-02-E-BPA-13, at 21-22.

BPA adopted the equivalent of an 88 percent TPP standard as a long-term policy in 1993, after conducting an extensive public consultation and review process and after litigating the proposed standard in the 1993 rate proceeding. At the time of the 1993 rate case, reserves were plummeting due to drought conditions, unanticipated fish flow costs, and low aluminum prices. To mitigate the rate "spike" that would result from implementing the standard in full in FY 1994-1995, BPA agreed to a one-time phase-in of the standard in that rate period. *Id.* at 23. Even by relaxing the TPP goal, conditions caused BPA to raise rates by an average of 16 percent. *Id.* In the 1996 rate case, BPA's price competitiveness, its ability to retain customers, and its long-term ability to recover costs were threatened. BPA's ability to meet its statutory mission, including cost recovery requirements, was judged to be in jeopardy if the competitive challenge were not met. Accordingly, in addition to other actions, BPA reduced its TPP target in rates for FY 1997-2001. *Id.* at 25. The Administration acquiesced to BPA's relaxation of the TPP goal in rates for FY 1997-2001. *Id.*

The conditions prevailing in 1993 and 1996 that caused BPA to relax its TPP target then are not present today. DeWolf *et al*., WP-02-E-BPA-13, at 26; DeWolf *et al*., WP-02-E-BPA-39, at 2. Today, reserves are strong and building, power costs are below market price expectations, demand for Subscription products is strong, and the rate pledge is being met with an 88 percent TPP. DeWolf *et al*., WP-02-E-BPA-39, at 2. Further, BPA includes a DDC that will rebate or otherwise distribute reserves that accumulate in excess of what is needed to meet the TPP goal. *Id.* at 12. Hence, there are no compelling reasons why the TPP goal of 88 percent should not be implemented in full in the 2002 rates.

Evaluation of Positions

BPA adopted the equivalent of an 88 percent TPP standard as a long-term policy in 1993. This policy standard, ". . . reflects consideration and balancing of BPA's responsibilities to keep rates as low as possible while ensuring its ability to carry out its legally mandated responsibilities required under the Northwest Power Act in a sound and business-like manner." 1993 ROD, WP-93-A-02, at 71-72. Adopting the standard sets a precedent ". . . that BPA shall adhere to in future rate cases, absent a determination by the Administrator that the policies should be modified to meet BPA's changing operating environment." *Id*. at 68. The policy included no "expiration date" as suggested by Vanalco and Alcoa. BPA does not propose, indeed no party to this rate proceeding has proposed, that the policy be changed to meet the changing operating environment criterion. And indeed, BPA does not need to have a formal TPP policy in place to be able to implement such a goal in its rates. Even if the policy did have a 10-year "expiration date," it would apply to this rate proposal. The standard is to be applied in the ratesetting processes, and this rate case is clearly within 10 years of the policy being established.

Serious financial and marketing problems prevented BPA from implementing the standard in full in previous rate filings. In 1993, financial reserves were plummeting due primarily to drought conditions, and rates were already being hiked substantially. In the 1993 ROD, BPA decided to implement the new standard on a one-time phase-in basis at less than the full 88 percent equivalent. In 1996, industry restructuring and new competitive pressures threatened BPA's competitive position and long-term ability to attract and retain customers and to recover costs. BPA cut costs substantially and, among other actions, reduced the TPP target to 80 percent for purposes of the FY 1997-2001 rates. Unlike in the current rate case, the Administration agreed to the TPP reduction in 1996.

None of the conditions that caused BPA to relax its TPP goal in 1993 and 1996 prevails today. *See* DeWolf *et al,* WP-02-E-BPA-13, at 26. Unlike in 1993, the PF rate is not being increased but is being stabilized at 1996 levels. Reserves are building, not plummeting, as demonstrated in an increase in reserves from $559 million in 1998 to $670 million in 1999. *Id.* at 24. The 1999 level of reserves is $235 million above the level projected in the 1996 rate case. And unlike in 1996, when price competition required BPA to reduce rates, the PF and other rates being set today are substantially below market price expectations, and demand for Subscription products is greater than supply. *Id.* at 26.

The parties are correct that Principle No. 3 allows a TPP level as low as 80 percent. The Principles do not require 88 percent, but establish 88 percent as the goal that BPA should strive to meet. DeWolf *et al*., WP-02-E-BPA-13, at 26. The DSI proposal for an 80 percent TPP target falls within the allowable range, and it is no lower than BPA's 1996 precedent. But the DSI proposal falls short of the Principle No. 3 goal. No party has presented a persuasive argument as to why BPA should deviate from its goal of 88 percent.

Several tribal and constituent groups contend that BPA's proposal variously underestimated risks, misinterpreted and misapplied the standard, and otherwise failed to mitigate risks adequately, thus causing the proposal to fail to achieve the TPP standard. Relaxing the TPP standard would exacerbate their concerns. *See* ROD section 5.4, *supra,* and the issues following in this section.

The Principles and the 10-Year Financial Plan establish 88 percent as the TPP goal that BPA should strive to achieve. BPA accepts and is attempting to implement this goal in full while at the same time meeting its rate pledge and fulfilling its environmental obligations. No party has successfully rebutted BPA's contention that conditions prevailing in 1993 and 1996 are not present today. In their brief on exceptions, Alcoa/Vanalco raised a new argument that some of the same conditions that prevailed in 1993 also exist now regarding DSI survivability which permitted BPA to vary from the announced TPP policy. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 36. However, BPA did not need to lower TPP to improve the probability of DSI smelter survival, to the extent it can, consistent with its other rate goals, including achieving a TPP of 88 percent during periods of low aluminum prices and high market power prices. *See* ROD section 15.5 *infra*.

The parties have presented no persuasive arguments or demonstrated that there are extenuating circumstances that should drive BPA to relax its goal in this rate proceeding.

Decision

BPA is implementing the 88 percent TPP goal in the final 2002 power rates.

Issue 3

Whether BPA's calculation of TPP inadequately accounts for risk by not explicitly addressing multiple deferrals within the rate period.

Parties' Positions

Four parties argue in their initial briefs that BPA should account for the financial cost of multiple deferrals in its calculation of TPP. NEC/SOS Brief, WP-02-B-NA/SA-01, at 29-30; OPUC Brief, WP-02-B-OP-01, at 7-8; UCUT Brief, WP-02-B-UC-01, at 26; and CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 43-44. As argued by OPUC:

> BPA's calculation of TPP does not account for the financial consequences of multiple Treasury deferrals within the rate period. . . . Under BPA's method of calculating TPP a single deferral of a few million dollars is treated exactly the same as multiple deferrals of hundreds of millions of dollars per year. . . . In essence, BPA claims that, for purposes of setting rates, the cumulative magnitude of Treasury deferrals within the rate period is irrelevant.

OPUC Brief, WP-02-B-OP-01, at 7-8.

NEC/SOS further note:

> . . . if a deferral does occur it is likely to be multiple and large. (61 percent of deferrals are multiple, averaging about 1.85 deferrals in any game which has deferrals . . .)

NEC/SOS Brief, WP-02-B-NA/SA-01, at 30.

CRITFC/Yakama state that "Bonneville's analysis treats multiple deferrals the same as a single miss. This clearly understates the risk to Treasury." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 43. CRITFC/Yakama support the analysis and arguments advanced by NEC/SOS and OPUC on this matter. *Id.* at 43-44.

UCUT urges BPA "to calculate TPP in such a manner that numerous failures to make Treasury payment during the rate period for a particular scenario are not treated as one failure, but are treated as numerous failures" and cites NEC/SOS and OPUC testimony. UCUT Brief, WP-02-B-UC-01, at 26.

NEC/SOS argue that "[f]ailure of BPA to account for multiple treasury deferrals violates the agency's requirement to follow sound business principles." NEC/SOS Brief, WP-02-B-NA/SA-01, at 30.

OPUC proposed that BPA "should set its rates and risk mitigation strategies such that there is at least a 90 percent probability that reserves will be at least $500 million in 2006." Grist and Carver, WP-02-E-OP-01, at 10.

In their briefs on exceptions, both CRITFC/Yakama and OPUC referred to the decision on this issue in the Draft ROD as "arbitrary and capricious" and argued that multiple misses of Treasury payments somehow meant that BPA was setting its rates too low. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 24-25; OPUC Ex. Brief, WP-02-R-OP-01, at 6. OPUC further adds:

> BPA relies primarily on the specter called "rate stability" to reject the suggestion that its failure to account for multiple treasury deferrals leaves substantial risk unaccounted for by the risk mitigation strategy.

Id.

NEC/SOS claims that BPA misrepresented NEC's direct testimony in the Draft ROD:

> In BPA's last paragraph before its draft decision (p. 7-13), BPA charges that the NWEC proposal to address the multiple deferral risk worked out to a rate increase of 3-5 mills/kWh. But in actuality, what NWEC's witness testified was, "An additional PNRR of about $46 million per year over the basecase…was necessary to reach that goal (about ¾ of a mill per year over BPA's initial proposal)." (WP-02-E-NA-01, at 6). The 3-5 mills BPA cites came from a statement 8 pages later that estimated the rate increase needed to cure a much larger problem than that of multiple deferrals: satisfying Principle No. 4. Once again BPA resorts to this sort of cheap misrepresentation to cover up its weak case.

NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 18.

<u>BPA's Position</u>

Since the 1993 rate case, BPA has defined Treasury Payment Probability as the likelihood of BPA making all of its annual Treasury payments within a rate period on time and in full. 1993 ROD, WP-93-A-02, at 68. The numerical value of the standard (*e.g.*, 88 percent) refers to the percentage of possible sets of future conditions for the rate period within which BPA never defers any of its payments to Treasury. Lovell *et al.*, WP-02-E-BPA-40, at 4. By setting the standard in such a fashion, an ending reserves value in any year of a single ToolKit game needs to fall to $50 million dollars only once in the five-year period for that game to be counted as a failure. DeWolf *et al.*, WP-02-E-BPA-13, at 21-25.

The ToolKit model has been used since the 1993 rate case to test for ability of BPA's risk mitigation measures to achieve the TPP goal. Revenue Requirement Study Documentation, Volume 1, WP-02-E-BPA-02A, at 275. For each game, or alternative simulation of the rate period, ToolKit takes a net revenue deviation (the sum of the net revenue deviations calculated in RiskMod and NORM) and applies it to the previous year's ending reserves balance. *Id.* at 279-80. Reserves are not allowed to fall below $50 million. At that point, a deferral to Treasury is counted and the unpaid balance is rolled over to be paid in subsequent years. Missed amortization is not rescheduled for later years in the rate period, but missed interest payments are treated as a priority for the next year. *Id.* at 286-87. ToolKit is run using a very wide range of net revenue impacts. PNRR is increased until only 12 percent of the games (3,900 in the 2002 rate case) contain any deferrals whatsoever. *Id.*

Evaluation of Positions

In evaluating the adequacy of BPA's TPP Methodology, two key points need to be noted. First, a number of items on the record support the assertion that the current TPP methodology already requires that BPA adhere to a stringent standard for making its annual payments to Treasury.

- In spite of the fact that multiple deferrals have been present in ToolKit simulations used for rate setting since 1993, BPA has made all of its Treasury payments on time and in full since adopting the methodology. DeWolf *et al*., WP-02-E-BPA-13, at 22-24.

- Multiple deferrals are inevitable in ToolKit simulations of any rate periods longer than a single year, because BPA's Risk Analysis Methodology is explicitly designed to capture the combined effects of key risks on net revenues. Risk Analysis Study Documentation, WP-02-E-BPA-03A, at 1-2. Moreover, this range has been widened when necessary to reflect changes in the risk profile that BPA faces. Conger *et al*., WP-02-E-BPA-15, at 18.

- BPA's modeling methodology treats ToolKit games that have any deferrals in them whatsoever as a failure (*i.e.*, not part of the successful 88 percent)--even if ToolKit shows that, in that game, BPA will have paid off the debt incurred by that deferral by the end of the rate period. Lovell *et al*., WP-02-E-BPA-40, at 3-4. For the initial proposal, this meant that although only 4.4 percent of the reserves calculated in the 3,900 ToolKit games fell to the deferral level, 12 percent of the games were rejected.

Id.

Ultimately, whether a particular TPP standard is deemed adequate or not is dependent upon the philosophy or general approach to risk that an organization adopts. A general approach to risk provides a basis for an organization's risk tolerance; it weights the cost of risk mitigation against the acceptability of the risk remaining after mitigation measures have been taken.

NEC/SOS, OPUC, CRITFC/Yakama, and UCUT are all concerned with guaranteeing that the worst of worst-case conditions are covered by some combination of PNRR and CRAC. NEC/SOS Brief, WP-02-B-NA/SA-01, at 30; OPUC Brief, WP-02-B-OP-01, at 7-8; CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 43; UCUT Brief, WP-02-B-UC-01, at 26.

BPA's TPP modeling methodology, however, has never been one of worst-case planning, but, like many other businesses, planning for an acceptable level of risk (defined by the TPP standard). 1993 ROD, WP-93-A-02, at 68-72. Moreover, by accepting a 95 percent TPP in 1993 (a two-year rate period) and an 88 percent TPP in 1996 (a five-year rate period), parties in BPA rate cases and FERC have recognized that less than 100 percent protection against risk is acceptable. BPA's modeling methodology, involving NORM and RiskMod in the risk analysis step, weights the impact of risks by their likelihood of occurrence. Revenue Requirement Study Documentation, Volume 1, WP-02-FS-BPA-02A, at 268-269. In direct testimony, BPA provided a graphic representation of just how wide a range of risk impacts was addressed by the risk mitigation measures in the initial proposal. Lovell *et al*., WP-02-E-BPA-14, Attachment 2. BPA stated that "[i]f no risk mitigation measures were employed (other than FCCF and section 4(h)(10)(C) credits …), the generation function's predicted ending reserves for FY 2006 would range from -$3.5 billion to $3.3 billion with a mean value of $372 million." Lovell *et al*., WP-02-E-BPA-14, at 11, and Attachment 2, Figure 1. The worst games were the product of sequences or combinations of negative outcomes, while the best games represented multiple "windfalls" or combinations of conditions that together produced very high ending reserves. ***Id.*** at 10-11. This extremely large variation in ending reserves reflects just how wide a range of potential risks was taken into consideration.

When the full set of risk mitigation measures described in the initial proposal was modeled, ending reserves for FY 2006 were distributed from $50 million to $4.1 billion, with an expected value of $1.26 billion (assuming no distributions under the DDC). Lovell *et al*., WP-02-E-BPA-14, at 10-11. NEC is correct that 61 percent of the games with deferrals contain multiple deferrals, NEC/SOS Brief, WP-02-B-NA/SA-01, at 30; however, this is only slightly over 7 percent of the total games (*i.e.*, .61*.12 = .0732 or 7.32 percent). Moreover, the large debt that BPA would incur in the worst cases, part of the risk that BPA deems acceptable, when weighted against the full range of ending reserves modeled in ToolKit, has a relatively minor effect on average ending values in the rate period. The sum of the average deferrals in each of the five years is $56.4 million; this sum comprises both deferred interest and deferred principal payments. Deferred interest payments for years 2002-2005 are repaid later in the rate period. Therefore, the impact of deferrals on average ending reserve levels can be no more than, and is probably less than, $56.4 million. Revenue Requirement Study Documentation, Volume 1, WP-02-E-BPA-02A, at 345. Thus, viewed from the standpoint of expected impact, the fact that deferrals occur in 12 percent of the games or that multiple deferrals occur in roughly 7 percent of the worst cases is not an indication that the method of calculating TPP is exposing BPA to undue risk.

Second, changing the way the TPP is calculated, or applying an alternative or supplementary methodology, would require a wholesale redefinition of the purpose of the TPP measure, the method of its calculation, and the establishment of a revised target. This would necessitate, among other things, a substantial change in precedent for BPA and require the development of a new political consensus around the resulting calculation.

The TPP standard has always evaluated the probability of remaining deferral-free for an entire rate period. The modeling methodology has never applied a different weight to games in which multiple deferrals occurred, and was never intended to. The 95 percent standard for two-year rate periods was derived in the context of this definition. As stated in the 1993 ROD:

> . . . the standard reflects consideration and balancing of BPA's responsibilities to keep rates as low as possible while ensuring its ability to carry out its legally mandated responsibilities required under the NW Power Act in a sound and business like manner . . . BPA shall adhere to [this precedent] in future rate cases, absent a determination by the Administrator that the policies should be modified to meet BPA's changing operating environment.

1993 ROD, WP-93-A-02, at 68, 71.

If the definition had been different, a different number would have been identified. The argument by the parties describes a design choice, made long ago, not a defect in the standard. It is not reasonable to take the 95 percent standard for two-year periods, derived in the context of deferral-free probability, and redefine the standard. The 88 percent goal of TPP applies to a specific calculation, and to use an average annual probability of Treasury payment or another standard that weights games with multiple deferrals more heavily than games with single deferrals would require a recalculation of the numerical standard. Lovell *et al*., WP-02-E-BPA-40, at 4.

NEC and OPUC were the only parties to propose any alternatives to BPA's calculation. Both parties submitted an alternative methodology for calculating TPP and an additional metric for assessing the size of the target ending reserves for the FY 2002-2006 rate period. The TPP calculation was designed to capture the effects of multiple deferrals. Weiss, WP-02-E-NA-01, at 2-7; Grist and Carver, WP-02-E-OP-01, at 2-5. BPA demonstrated that this alternative TPP calculation contained a statistical flaw. Lovell *et al*., WP-02-E-BPA-40, at 2. This fact is acknowledged by the parties:

> After consideration of BPA's argument, NWEC agrees that its analysis was indeed flawed. However, proving that our attempt to account for the risk of multiple deferrals contained errors in no way dismisses the basic truth to the claim in the first place: *i.e.,* that the methodology utilized by Bonneville simply doesn't account for the risk of multiple deferrals either . . .

NEC/SOS Brief, WP-02-B-NA/SA-01, at 30. OPUC adds:

> While BPA demonstrated OPUC's proposed method to account for the risk of multiple deferrals contained errors, it did not dismisses [sic] the basic truth to the claim that the method used by Bonneville doesn't account for the risk and financial costs of multiple deferrals.

OPUC Brief, WP-02-B-OP-01, at 7.

Adding a minimum level of reserves criteria as proposed by OPUC and NEC (or substituting it for TPP) would impair BPA's ability to maintain its promise of rate stability in the

FY 2002-2006 rate period. The proposal for a design to meet a target reserve level described in NEC's direct testimony would ". . . work out to rate increases of 3 or 5 mills/kWh," Weiss, WP-02-E-NA-01, at 7-15; while the proposal presented in OPUC's direct testimony, Grist and Carver, WP-02-E-OP-01, at 9-12; which was based upon a CRAC design with high thresholds and annual caps, would result in less rate stability than BPA sought in its initial proposal. Lovell *et al*., WP-02-E-BPA-40, at 10-12. This issue is discussed further in ROD section 5.4.7.1.

(As quoted *supra*, NEC/SOS claimed that BPA misrepresented the direct testimony of NEC's witness by citing a potential rate increase resulting from the establishment of a target reserves criteria as evidence of the rate impacts attributable to NEC's alternative TPP calculation. In fact, BPA *was* referring to the effects of the target reserves criteria, not the alternative TPP calculation, in the statement in the Draft DOD that NEC/SOS took issue with. BPA would have no reason to be concerned with assessing rate impacts that were solely the result of a TPP methodology that the authors themselves eventually rejected as flawed. It is hoped, however, that the wording changes made for this final ROD have eliminated any confusion on this matter.)

A few points raised *supra* in this evaluation of positions need to be amplified in response to the issues raised by CRITFC/Yakama and OPUC in their briefs on exceptions. BPA is not rejecting the parties' argument on the significance of multiple deferrals based on the "specter of rates stability." As can be seen *supra* in the evaluation of positions, the effects of rate stability were cited as only one of the reasons BPA is not entertaining the idea of a minimum reserves criteria.

BPA is arguing that its approach to dealing with risk, which has been subjected to scrutiny since 1993 by rate case parties and FERC, continues to be a reasonable one. The presence of multiple deferrals is not a development new to the 2002 rate case that, in itself, signals any change in BPA's risk exposure, but an inevitable and constant consequence of the risk analysis and mitigation methodology BPA developed and uses. Further, the fact that a very small percentage of ToolKit runs display very large deferrals is not an indication that BPA is exposing itself and the region to undue risk. By its nature, the analysis is designed to produce some scenarios with very high impacts but low probabilities of occurrence, since BPA's business environment contains risks with those characteristics. The significance of both multiple deferrals and large deferrals can be assessed adequately only by putting them in context, viewing the specific impacts of worst cases in relation to their expected effects; and as can be seen *supra*, BPA has done this.

Decision

BPA's method of calculating TPP is reasonable and the product of past review. The fact that the TPP calculation does not explicitly address multiple deferrals within the rate period does not expose the agency to unnecessary risk.

Issue 4

Whether BPA would meet its TPP goal if Fish and Wildlife Alternative 13u is chosen.

Parties' Positions

CRITFC/Yakama argue that BPA would not be meeting its 88 percent TPP goal and, by extension, Principle No. 3, because "[i]f a decision was made this year to implement alternative 13u (the alternative that is similar to the tribal restoration plan), Bonneville's TPP probability would reduce to 65 percent. WP-02-E-CR/YA-01, Attachment 1." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 27-28.

BPA's Position

Because BPA must be prepared for the full range of uncertainties that are observable at the time the rate case studies are conducted, the ToolKit model applies an 88 percent TPP standard to a set of 3,900 five-year rate period games that cover the full spectrum of operating and non-operating risks. Revenue Requirement Study Documentation, Volume 1, WP-02-E-BPA-02A, at 280. Each of the five-year games begins with a particular ending reserves balance from the current rate period, and then applies a unique set of net revenue deviations to produce ending reserve values for FY 2002-2006. *Id.* Three hundred games were run for each of 13 Fish and Wildlife Alternatives. *Id.* Each of the Fish and Wildlife Alternatives had its own associated set of annual costs and distribution of net revenues. *Id.* Within this range of 3900 games, each of the 13 Fish and Wildlife Alternatives was given equal weight. Lovell *et al.*, WP-02-E-BPA-14, at 6.

Evaluation of Positions

CRITFC/Yakama state that "Bonneville's TPP probability would reduce to 65 percent." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 27. CRITFC/Yakama refer to an analysis that BPA and other Federal agencies considered a few months before BPA completed its initial proposal. Sheets, WP-02-E-CR/YA-01, Attachment 1, at 5-6. This analysis was provided by BPA to NEC in response to a data request. The analysis is entitled "Approximate 2002-2006 and 2007-2011 Impacts of 13 (18) F&W Alternatives" and includes the Conditional TPPs for 2002-2006 associated with each of the Fish and Wildlife Alternatives. *Id.* The Conditional TPP for Fish and Wildlife Alternative 13u shows a Conditional TPP of 65 percent. *Id.* These Conditional TPPs together average 88 percent, but vary depending upon the severity of the mitigation measures encompassed by different Fish and Wildlife Alternatives--some higher, some lower. *Id.*

Given the way TPP has been defined as applying to the full range of possibilities BPA considers at the time of writing its proposals, BPA would not be missing its 88 percent TPP goal if Alternative 13u, or any other Alternative, was ultimately selected. The reason for having a standard that addresses the uncertainty in the selection of a Fish and Wildlife Alternative is that at the present time, this selection is uncertain. Conditional TPP, which was not a criterion applied to the initial proposal, signifies the condition where the outcome of the fish decision is known. At some point in the future, an Alternative will be selected, and at that time the associated impacts will no longer be an uncertainty, but that is not the case now.

Decision

Whether Fish and Wildlife Alternative 13u is selected is irrelevant to the issue of whether BPA meets its 88 percent TPP goal.

Issue 5

Whether BPA should increase TPP to 100 percent in FY 2006.

Parties' Positions

UCUT stated that:

> BPA should consider increasing TPP to 100% for only the year 2006, the last year of the rate period. If there is a possibility of treasury payment deferral in that year, there will obviously be no ending reserves to mitigate risk of rate shock in the next rate period as is required to meet Fish and Wildlife Principle No. 4. UCUT Brief, WP-02-B-UC-01, at 26.

BPA's Position

Fish and Wildlife Principle No. 3 states:

> BPA will demonstrate a high probability of Treasury payment in full and on time over the five-year period.
>
> - A 100 percent probability of Treasury payment is not achievable, but BPA's rates must be designed to maintain or improve TPP, even in the face of the range of possible fish costs.
>
> - BPA will demonstrate a probability of Treasury payment in full and on time over the five-year period at least equal to the 80 percent level established in the last rate case and will seek to achieve an 88 percent level.

DeWolf *et al*., WP-02-E-BPA-13, at 22.

Fish and Wildlife Principle No. 4 provides:

> Given the range of potential fish and wildlife costs, BPA will design rates and contracts which will position BPA to achieve similarly high Treasury payment probability for the post-2006 period by building financial reserve levels and through other mechanisms.

Id.

BPA is implementing the Principles in the 2002 power rates. *Id.* at 7. As part of this implementation, an 88 percent TPP is being targeted in order to meet a BPA long-standing TPP policy standard and to fully meet both Principle No. 3 and Principle No. 4. *Id.* at 22.

Evaluation of Positions

Although it may appear on the surface that raising the TPP to 100 percent for a single year would have little effect on rates, this is not the case. BPA illustrated the width of the band of uncertainty surrounding the rate case in response to another issue *supra*, stating: "[i]f no risk mitigation measures were employed (other than FCCF and section 4(h)(10)(C) credits . . .), the generation function's predicted ending reserves for FY 2006 would range from -$3.5 billion to $3.3 billion with a mean value of $372 million." Lovell *et al*., WP-02-E-BPA-14, Attachment 2, Figure 1. The reason for the extreme width of the band of uncertainty is revealed by referring to the net revenue deviations presented in Table 74 of the Risk Analysis Study Documentation, WP-02-E-BPA-03A. It would take $1.03 billion to cover the level of net revenue deviations for FY 2006 at the 1 percent level. *Id.* Thus, although this value represents an extreme outlying net revenue deviation value, to achieve a 100 percent TPP for the final year of the FY 2002-2006 rate period would mean covering this amount with prohibitively high PNRR and/or CRAC. *Id.*

In addition, the Principles allow BPA some flexibility in demonstrating a high probability of Treasury payment in full and on time over the five-year rate period. Principle No. 3 recognizes that "[a] 100 percent probability of Treasury payment is not achievable" and provides for a demonstration of Treasury payment probability at least equal to the 80 percent level established in the 1996 rate case, while seeking to achieve an 88 percent level. DeWolf *et al*., WP-02-E-BPA-13, at 22.

BPA will adhere to its 88 percent TPP target, which is a long-standing BPA TPP policy standard. This 88 percent TPP level demonstrates a high probability of Treasury payment in full and on time over the five-year rate period and fully meets both Principle No. 3 and Principle No. 4.

Decision

BPA will not increase TPP to 100 percent in 2006.

7.3 Cost Recovery Adjustment Clause (CRAC) Design

Issue 1

Whether BPA's CRAC thresholds should be based on financial reserves rather than AANR.

Parties' Position

PPC states that the design of the CRAC implementation levels should rely on financial reserves, the same basis as BPA's other risk estimates. By instead using AANR, BPA may alter the circumstances in which the CRAC triggers and the circumstances in which the proposed dividend distribution clause may be invoked. PPC Brief, WP-02-B-PP-01, at 15. Specifically, PPC adds, the use of AANR to trigger CRAC would allow BPA to force the CRAC to trigger even if reserves exceeded $1 billion, and would allow BPA to manipulate the AANR process based upon forecasts. The CRAC should trigger based on BPA's actual financial conditions and level of reserves at the end of its fiscal year. Hansen *et al.*, WP-02-E-PP-03, at 4-8.

BPA's Position

BPA designed both the CRAC and the DDC to trigger based on AANR because accumulated net revenues are subject to financial audit, thus allowing independent verification of actual results. Revenue Requirement Study Documentation, Volume 1, WP-02-FS-BPA-02A, at 291-92, 297-298. Reserves are not subject to audit or independent verification. Net revenues are more readily segregated by generation and transmission function than reserves because of financial systems design and financial reporting practices. Lovell *et al*., WP-02-E-BPA-14, at 7. BPA chose to use AANR rather than reserves to minimize contention, and to help ensure that CRAC and DDC implementation is transparent and not subject to manipulation.

BPA's proposal assures its customers and constituents that reasonable actions will be taken before a CRAC triggers. DeWolf *et al*., WP-02-E-BPA-39, at 44-45. When AANR are within $150 million of the next year's CRAC threshold, BPA will provide customers and interested parties with an analysis of the causes of BPA's relative financial decline compared to the rate case plan, and propose a prioritized list of potential actions to avert or mitigate the need for a CRAC. *Id*. These actions presumably would include, but not necessarily be limited to, cost management actions. BPA will seek public comments and advice over a two-month period on these actions to avert or reduce a rate adjustment. On a quarterly basis, BPA will post on its web site the aggregate financial results for the generation function including AANR. Year-end information will be based on audited actual financial results. BPA will also provide preliminary, unaudited year-to-date aggregate financial results for generation quarterly on its web site. BPA will also provide a forecast of AANR no later than August 31 of each year. *Id*. In a similar fashion, the DDC evaluation process will begin when AANR exceeds a threshold value of $250 million. *Id*. at 12-13.

As was indicated in Lovell *et al*., WP-02-E-BPA-14, at 13, for the final proposal, BPA recalculated the AANR-based CRAC and DDC thresholds, using the same methodology as in the initial proposal but using 1999 actual financial data and more current reserves and net revenue forecasts. Revenue Requirement Study Documentation, Volume 1, WP-02-FS-BPA-02A, chapter 12, Appendix 1. BPA's projections of FY 2002 starting reserves and net revenues changed markedly from the initial proposal. *Id.* This recalibration was necessary so that the AANR-based thresholds would be consistent with the reserves assumptions underlying the CRAC analysis in the final proposal. If this change had not been made, the AANR-based thresholds to be used during implementation would have triggered at a level equivalent to a reserves threshold lower than $300 million in FY 2001-2002 and $500 million in FY 2003-2005. This would result in BPA undershooting the 88 percent TPP standard.

The methodology by which the AANR-based thresholds were calculated are described in detail in Appendix 1 of the Revenue Requirement Study Documentation. The basic steps are as follows:

1. BPA projects deterministic starting reserves for the years in the next rate period. *Id.*

2. These reserves values are then compared to the CRAC (or DDC) thresholds, expressed in terms of cash reserves--$300 million for FY 2001-2002, $500 million for FY 2003-2005. This determines the gap between projected reserves and the CRAC trigger point; that is, the magnitude by which reserves would need to fall before CRAC would trigger. *Id.*

3. BPA projects accumulated net revenues (ANR). For the initial proposal, the starting point for net revenue accumulation was the end of FY 1998. This was the last year for which audited actuals were available at that time. Since that time, end-of-year FY 1999 actuals have become available, and so, for the final proposal, BPA revised the starting point for net revenue accumulation to the end of FY 1999. *Id.*

4. To derive the appropriate annual CRAC and DDC thresholds, expressed in terms of AANR, the gap value derived in step 2 is subtracted from the AANR value for that year. In other words, the CRAC and DDC thresholds are calculated so that for these mechanisms to trigger, AANR would need to change by exactly the same magnitude as reserves did during the analysis used for setting rates (*e.g.* if the CRAC trigger threshold, expressed in terms of cash reserves, is $500 million less than projected reserves for a given year, the CRAC threshold expressed in terms of AANR should similarly be $500 million below projected ANR for that year). *Id.*

5. Finally, the AANR-based threshold values are rounded to more even values (e.g. -$373 is rounded to -$350). *Id.*

This recalculation resulted in slightly revised threshold values, after rebasing to end-of-year FY 1999 actuals. CRAC would trigger when AANR fell below -$350 million in FY 2001-2002 and at a level of -$250 million for FY 2003-2005 (the DDC would trigger at $250 million.)

Evaluation of Positions

BPA has functionally separated its power and transmission lines. *See* Burns and Elizalde, WP-02-E-BPA-08, at 2. BPA records accounting transactions by business line. The accounting structure specifies the business line at the transactional level to enable separate accounting of business line operations. Accrued revenues and accrued expenses are specified by business line when recognized, with administrative and support service costs assigned to business lines based on use of services and allocations. DeWolf *et al*., WP-02-E-BPA-13, at 31. The accumulated net revenues in the accounting structure are subject to financial audit, thus allowing independent verification of actual results. Lovell *et al*., WP-02-E-BPA-14, at 7. Thus, they are appropriately used for determining the threshold.

On the other hand, as with single-company financial systems, BPA's financial system does not track agencywide assets (cash, receivables) by business unit. Additionally, BPA's cash management policies do not treat these assets separately by business line. Due to reserves being held in a single agency account, the BPA fund, BPA's financial reserve levels by business line are less auditable than actual accumulated net revenues. A functional split of cash flows is difficult and imprecise.

Additionally, BPA believes it is highly unlikely that cash reserves and AANR would diverge significantly. Hansen *et al*., WP-02-E-PP-03, Attachment D. The PPC's concern is that using AANR could result in the CRAC triggering unnecessarily. BPA has instituted cost management safeguards to prevent this from happening. Specifically, when AANR are within $150 million of the next year's CRAC threshold, BPA will provide customers and interested parties with an analysis of the causes of BPA's relative financial decline compared to the rate case plan, and propose a prioritized list of potential actions to avert or mitigate the need for a CRAC. BPA will seek public comments and advice over a two-month period on these actions to avert or reduce a rate adjustment. BPA will also make aggregated generation financial data available on its web site quarterly. DeWolf *et al*., WP-02-E-BPA-39, at 44-45.

Decision

BPA will continue to set the CRAC thresholds based on AANR rather than reserves. BPA has included reasonable cost management safeguards against unnecessary triggering of the CRAC.

Issue 2

Whether a CRAC threshold equivalent of $300 million in reserves and an annual revenue maximum of $100 million (or even lower values) should be set for all five years of the FY 2002-2006 rate period.

Parties' Positions

Both the PPC and NRU argued that BPA should adopt the CRAC BPA used in its technical workshops before the initial proposal was drafted--with constant annual thresholds of $300 million and constant annual caps of $100 million. PPC Brief, WP-02-B-PP-01, at 5; Saven, WP-02-E-NI-01, at 11-12. NRU's recommendation was presented as part of an alternative proposal that substituted a reverse CRAC for the DDC, assumed no risk impacts on reserves in the remainder of the current rate period, and produced a TPP of 85.5 percent. *Id.* at 12-17.

In its brief on exceptions, OURCA argued that BPA "should correctly set the power rates for its customers in the first instance rather than rely on implementation of a CRAC." OURCA Ex. Brief, WP-02-R-OU-01, at 3-4.

BPA's Position

BPA used three criteria to guide the development of CRAC thresholds and annual caps in the initial proposal. Lovell *et al*., WP-02-E-BPA-40, at 9-10. First, together with PNRR, CRAC levels needed to be set so that BPA would have an 88 percent probability of making all of its Treasury payments on time and in full over the FY 2002-2006 rate period. *Id.* at 10. Second, the CRAC values needed to be set high enough to allow BPA to meet its rate goals. *Id.* Finally, CRAC thresholds and caps needed to be set so that, to the extent possible given the first two criteria, they would have minimum impacts on the stability of BPA's firm power rates. *Id.* The values used for the this proposal--reserves thresholds of $300 million in FY 2001 and 2002 and $500 million in FY 2003-2005, and annual caps of $125 million if the threshold is crossed in

FY 2001, $135 million in FY 2002, $150 million in FY 2003, $150 million in FY 2004, and $87.5 million in FY 2005--meet these criteria. Lovell *et al*, WP-02-E-BPA-14, at 6-9.

Evaluation of Positions

Without the use of CRAC, BPA could not set rates so as to meet its TPP goal and its commitment to the rate pledge. PPC's and NRU's proposals fail to meet the 88 percent TPP standard. As noted elsewhere in this section of the ROD, in the 1993 rate case BPA established a target TPP of 95 percent for two-year rate periods. 1993 ROD, WP-93-A-02, at 68-72. This was converted into a five-year TPP of 88 percent in the 1996 rate case. Because of market conditions at that time, however, BPA ultimately lowered the TPP target to 80 percent, noting that "(r)educing the Treasury repayment probability for this (1996) rate case is one of the steps BPA is proposing to help maintain competitive rate levels. 1996 ROD, WP-96-A-02, at 89. The conditions that warranted this reduction in the TPP target are no longer present. DeWolf *et al.*, WP-02-E-BPA-13, at 27. The 88 percent standard is consistent with established policy and is appropriate. *Id.* at 22. The reduction in TPP proposed by the parties is not acceptable. Lovell *et al.*, WP-02-E-BPA-40, at 13. Also, the PPC and NRU proposals fail to satisfy the three criteria BPA established to guide the development of the CRAC thresholds and annual caps.

Decision

BPA will not establish a CRAC threshold equivalent of $300 million in reserves and an annual revenue maximum of $100 million for all five years of the FY 2002-2006 rate period. The values used for the proposal--reserves thresholds of $300 million in 2001 and 2002 and $500 million in 2003-2005, and annual caps of $125 million if the threshold is crossed in 2001, $135 million in FY 2002, $150 million in FY 2003, $150 million in FY 2004, and $87.5 million in FY 2005--meet the three criteria BPA used to guide the development of CRAC thresholds and annual caps and will continue to be used in the final 2002 rates.

Issue 3

Whether CRAC thresholds and annual maximums should be raised.

Parties' Positions

The DSIs argue that BPA should "rely primarily on a modified CRAC, as explained by Messrs. Schoenbeck and Bliven of RCS, that would be limited so that customers would not pay more than the rate level plus CRAC proposed by BPA . . ." DSI Brief, WP-02-B-DS-01, at 47. *See also supra* for discussion of the section 7(n) issue. The proposal referred to by the DSIs was one of three presented in direct testimony that argued for raising the CRAC threshold and annual maximum values. The Joint DSIs recommended "that BPA set its rates based on expected costs, that BPA include no PNRR in rates, and that BPA structure the Cost Recovery Adjustment Clause to achieve the 80 percent TPP." Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 10. The Joint DSIs proposed a CRAC design that employed a CRAC threshold of $675 million across all five years of the rate period with annual caps set at levels $127 million higher than BPA's proposed CRAC revenue limits. *Id.* at 11. The DSIs recommended "setting the CRAC revenue limits at $252 million, $262 million, $262 million, $277 million, $277 million [sic], and $302 million for FY 2002-2006 respectively." *Id.* In addition, "[t]he targeted CRAC recovery would be the amount needed to restore reserves to $675 million, but not more than the annual limit. This plan provides an 81 percent TPP." *Id.* In their brief on exceptions, the DSIs argue that BPA's refusal to modify the CRAC as they requested is arbitrary, capricious and contrary to law. DSI Ex. Brief, WP-02-R-DS-01, at 18. They assert that BPA appears to assume that customers would prefer to pay millions of dollars more for certain each year in higher rates, rather than take a chance on having to pay such funds later. *Id.* This assumption, they claim, lacks any support in the record and is arbitrary, capricious, and contrary to the design of BPA's statutes which require it to behave in a business-like fashion. *Id.*

OPUC proposed two alternative CRAC designs and explained that "BPA could adopt a CRAC that triggers at a higher threshold and that has a higher annual limit, thus allowing the collection of more revenues if and when required." Grist and Carver, WP-02-E-OP-01, at 10. Under the first design, the CRAC threshold grows by $200 million increments each year, from $300 million to $1.1 billion, while the annual limit is a constant $300 million. *Id.* at 11. Under the second design, each year's CRAC cap (or annual limit) is set equal to the CRAC threshold for that particular year. The progression of these values from FY 2002 to FY 2006 is $300 million, $400 million, $500 million, $500 million, and $725 million. *Id.* OPUC also argued that ". . . BPA should determine the TPP of its final proposal based on 5-year average TPP of 88 percent . . ." *Id.* at 10. Using OPUC's measure of TPP, the first CRAC design met the alternatively defined 88 percent TPP standard with $105 million PNRR, while the second CRAC design met that same standard with $127 million PNRR. *Id.*

The IOUs argued that "BPA should eliminate the accumulation of reserves resulting from PNRR and provide a more robust CRAC." Stauffer *et al.*, WP-02-E-AC/GE/IP/MP/PL/PS-04, at 10. The IOUs asserted that a very large CRAC would not be expected if PNRR were eliminated. *Id*. The IOUs stated that "BPA's CRAC should not be capped . . ." *Id*. at 12. However, for analytical purposes, the IOUs ran the ToolKit model to find the CRAC thresholds and limits that would achieve 88 percent TPP. *Id*. at 10. Based on their analysis, the CRAC thresholds ranged from $500 million in the first year to $900 million in the fifth year, and caps ranged from $300 million in the first year to $500 million in the fifth year. *Id*. In their brief on exceptions, the IOUs claim that BPA ignored a key issue raised in the Draft ROD. They argue that CRAC and DDC together increase the likelihood of cost shifts to transmission customers by creating a mechanism that could end up giving money away that was needed later in the rate period. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 41. They assert that BPA should increase power rates to market before it attempts to surcharge transmission customers and employ the use of an uncapped CRAC. *Id.*

<u>BPA's Position</u>

BPA used three criteria to guide the development of CRAC thresholds and annual caps in the initial proposal. Lovell *et al.*, WP-02-E-BPA-40, at 9-10. First, together with PNRR, starting reserves, and access to the FCCF, CRAC levels needed to be set so that BPA would have an 88 percent probability of making all of its Treasury payments on time and in full over the FY 2002-2006 rate period. *Id.* at 10. Second, the CRAC values needed to be set high enough to allow BPA to meet its rate goals. *Id.* Finally, CRAC thresholds and caps needed to be set so that, to the extent possible given the first two criteria, they would have minimum impacts on the stability of BPA's firm power rates. *Id.* The values used for this proposal--reserves thresholds of $300 million in 2001 and 2002 and $500 million in 2003-2005, and annual caps of $125 million if the threshold is crossed in 2001, $135 million in FY 2002, $150 million in FY 2003, $150 million in FY 2004, and $87.5 million in FY 2005--met these criteria. Lovell *et al.*, WP-02-E-BPA-14, at 6-9.

<u>Evaluation of Positions</u>

From the standpoint of the criteria BPA used in formulating its CRAC design, the Joint DSI proposal suffers from two problems. "BPA's CRAC has an 11.8 percent probability that it would trigger during the rate period. The CRAC we propose has a 43.3 percent probability of triggering." Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 11. This CRAC design does not address the issue of rate stability, and it results in a TPP of only 81 percent, *Id.* at 11; which is considerably short of the 88 percent TPP target BPA has established.

With regard to OPUC's proposal, BPA demonstrated that OPUC's alternative calculation of TPP employed a methodology different from BPA's that was statistically invalid and could not be used as a substitute for assessing the success of meeting the Treasury payment goal. Lovell *et al.*, WP-02-E-BPA-40, at 10. This point was conceded by OPUC. OPUC Brief, WP-02-B-OP-01, at 7.

Using BPA's method of calculating TPP yields probabilities of 92.6 percent for OPUC's Example 1 and 91.3 percent for OPUC's Example 2. Lovell *et al.*, WP-02-E-BPA-40, at 11. BPA reran OPUC's Example 1 and Example 2 CRAC designs on ToolKit using the established TPP Methodology to arrive at the 88 percent TPP level. For Example 1, the high threshold levels cause CRAC to trigger on average 34 percent of the time over the rate period. *Id.* This is almost three times the number of CRAC triggers that BPA's design displayed (12 percent). *Id.* For Example 2, CRAC triggers at a rate more similar to BPA's design (17 percent), but the average annual rate increase is much higher. *Id.* Using a conversion of roughly $55 million in additional revenues to a 1-mill increase in rates, the average size of the revenue increase per CRAC access-that is, per trigger--in the OPUC design ($292.2 million per year) yields an average rate increase of 5.3 mills per year (with the high out-year threshold and cap resulting in a particularly severe 8-mill increase in FY 2006). *Id.* By contrast, in BPA's design the average size of a rate increase when CRAC triggers would be 2.4 mills, with the largest average increase in any given year being 2.9 mills. *See* Revenue Requirement Study Documentation, Volume 1, WP-02-FS-BPA-02A, at 333. Both of the OPUC designs would result in less rate stability than BPA sought in its CRAC design. *Id.*

The IOU proposal displays many similar characteristics. Relying solely on CRAC would result in unstable rates considering the average frequency at which the CRAC would trigger. In the IOU proposal CRAC triggers, on average, over 42 percent of the time over the five-year rate period (and nearly two-thirds of the time by FY 2005), with an average rate increase of 4.7 mills each time CRAC triggers. Lovell *et al.*, WP-02-E-BPA-40, at 12. The additional problems associated with an uncapped CRAC are discussed *infra* in the context of Issues 4 and 5. The rolling five-year forecast associated with the DDC is designed to prevent BPA from giving money away that was necessary for ensuring an adequate probability of making Treasury payments in the near future. *See* discussions *infra* in section 7.5 on the DDC.

BPA's CRAC thresholds and annual maximum values are reasonable and meet the 88 percent TPP standard. All of the proposals developed by the three parties would result in less stable rates for BPA's customers than BPA's CRAC design presented and evaluated in this case.

Decision

The CRAC thresholds and annual maximums will not be raised.

Issue 4

Whether CRAC should be capped.

Parties' Positions

Both UCUT and the IOUs support an uncapped CRAC. UCUT Brief, WP-02-B-UC-01, at 26; IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 57.

As noted *supra*, both PPC and NRU argued that the cap should be lowered from the values in BPA's initial proposal to a constant $100 million per year across the rate period.

BPA's Position

As noted *supra*, one of the criteria BPA used in guiding the design of the CRAC was rate stability within the FY 2002-2006 rate period. The thresholds and annual caps in BPA's initial proposal were set such that CRAC would trigger only infrequently and with relatively minor rate increases. Lovell *et al*., WP-02-E-BPA-40, at 10. "A more robust CRAC could well be so objectionable or onerous that BPA is effectively precluded from carrying it out as designed." Lovell *et al*., WP-02-E-BPA-14, at 9.

Evaluation of Positions

Looking at the magnitude of the year-to-year rate impacts of the IOU CRAC design reveals that, on average, CRAC triggers over 42 percent of the time over the five-year rate period (and nearly two-thirds of the time by FY 2005) with an average rate increase of 4.7 mills each time CRAC triggers. Lovell *et al*., WP-02-E-BPA-40, at 12. This illustrates why an uncapped CRAC would be undesirable: it would result in less stable rates for BPA's customers than the CRAC design presented in the initial proposal. Lovell *et al*., WP-02-E-BPA-40, at 12. Moreover, as noted *infra* in section 7.3 (five-year rolling forecast for CRAC), under BPA's proposal, customers would know that their rates could increase by no more than about 10 percent; with an uncapped CRAC, there would be no limit to how high their rates might rise.

An uncapped CRAC would result in substantially less stable rates for BPA's customers than BPA's CRAC design presented and evaluated in this case. The major group subject to CRAC argues that BPA should adopt lower limits than BPA proposed. BPA's caps on rate increases under CRAC are reasonable in terms of risk mitigation and marketing objectives.

Decision

BPA will include an annual cap on the CRAC.

Issue 5

Whether BPA has arbitrarily and unnecessarily limited the flexibility of the CRAC.

Parties' Positions

In support of the assertion that BPA has arbitrarily and unnecessarily limited the flexibility of CRAC, OPUC argues that BPA cites rate stability as a key goal in the rate case, but that:

> The exact nature or parameters of this "rate stability goal" cannot be ascertained from the record. The term apparently refers to rate changes caused by CRAC triggering within the 2002-2006 rate period or intra-period rate stability.

OPUC Brief, WP-02-B-OP-01, at 5.

They further argue that:

> BPA's only evidence of any quantitative evaluation of rate stability is related to the "rate pledge" and refers to BPA's "pledge" to keep the rates in the 2002-2006 period no higher than the 1996 rates. WP-02-E-BPA-17, p. 27-28. The quantitative "proof" of the rate pledge looks only at average base rates, and makes no assumptions regarding the effect of a CRAC trigger. Thus, the only rate stability directly addressed in BPA testimony refers to keeping rate changes low between the 1996 and 2002 rate periods.
>
> …The unstated premise of the claim of intra-period rate stability is that the introduction of additional risk will cause customers to avoid purchasing from BPA. Yet BPA has not identified any informal or formal guidelines or targets for the maximum annual percentage increase in a CRAC or maximum probability of a CRAC triggering in any year to support such an assertion.

Id. at 5-6.

In briefs on exceptions, several parties criticized BPA for its use of rate stability as a criterion for its CRAC design. These parties included the IOUs (WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 42-43), NEC/SOS (WP-02-R-NA/SA-01 at 18-20), and OPUC (WP-02-R-OP-01, at 7-8).

In conjunction with this issue, NEC/SOS and OPUC also raised an additional issue of inter-period rate stability. This issue will be addressed *infra* in section 7.7 of this risk mitigation chapter.

<u>BPA's Position</u>

Since the formulation of the Subscription Strategy, BPA has considered CRAC as an integral, but relatively modest, part of the risk mitigation package in developing its power rates. Subscription Strategy, at 14. CRAC, however, has been consistently characterized as an adjustment mechanism to base rates that generated most of the revenues BPA needed. *Id.*

> Subject to the rate case, BPA proposes using an adjustment to posted prices, known as a cost recovery adjustment clause (CRAC), in its firm requirements rate schedules. All net firm power load requirements customers would be subject to a CRAC. BPA believes that *a CRAC of about $100 million per year* would be adequate to maintain the desired Treasury Payment Probability, but the final determination of the amount will be made in the rate case.

Id. (emphasis added).

Although the CRAC design presented by BPA in the initial proposal ultimately raised this annual amount, it was by a rather small margin, with a maximum value between $125 and $150 million in FY 2001-2004 and $87.5 million in FY 2005. Lovell *et al*., WP-02-E-BPA-14, at 9. BPA noted one of the primary reasons for keeping the annual CRAC caps in this range:

> The CRAC must be designed such that political constraints do not prevent the mechanism from being implemented as modeled. A more robust CRAC could well be so objectionable or so onerous that BPA is effectively precluded from carrying it out as designed. The effect could be to shift risk to Treasury.

Id.

See supra for BPA's comparison of several other parties' CRAC proposals to its own CRAC proposal using three criteria to guide the development of CRAC thresholds and annual caps in the initial proposal. Lovell *et al*., WP-02-E-BPA-40, at 9-10. First, together with PNRR and other risk mitigation tools, CRAC levels needed to be set so that BPA would have an 88 percent probability of making all of its Treasury payments on time and in full over the FY 2002-2006 rate period. *Id.* at 10. Second, the CRAC values needed to be set high enough to allow BPA to meet its rate goals. *Id.* Finally, CRAC thresholds and caps needed to be set so that, to the extent possible given the first two criteria, they would have minimum impacts on the stability of BPA's firm power rates. This meant that CRAC would trigger only infrequently and with relatively minor rate increases. *Id.* The values used for this proposal--reserves thresholds of $300 million in 2001 and 2002 and $500 million in 2003-2005, and annual caps of $125 million if the threshold is crossed in 2001, $135 million in FY 2002, $150 million in FY 2003, $150 million in FY 2004, and $87.5 million in FY 2005--met these criteria. Lovell *et al.*, WP-02-E-BPA-14, at 6-9. While only two of these three criteria were linked to quantitative assessment, the 88 percent TPP and the rate goals, all three criteria were consistent with statements made by

BPA throughout the Subscription process about anticipated levels of CRAC and the feasibility of its implementation.

<u>Evaluation of Positions</u>

OPUC is correct in its assertion that "BPA's only evidence of any quantitative evaluation of rate stability is related to its 'rate pledge' and refers to BPA's 'pledge' to keep the rates in the 2002-2006 period no higher than the 1996 rates." OPUC Brief, WP-02-B-OP-01, at 5. As noted in the statement of BPA's position, this was not established as a hard criterion with a numerical threshold that determined the acceptance or rejection of a proposal. Rate stability is fundamentally a marketing judgment, with broad implications for competitiveness, a stable customer base, and stable revenues. However, OPUC's assertion is not tenable that "BPA's reliance on its claim of 'rate stability' to reject suggestions to improve the CRAC is arbitrary and is not supported by substantial evidence." *Id.* at 6.

First, BPA did not assert that any of the proposals offered by parties that relied on a more robust CRAC (including OPUC's proposal) failed to meet any specific threshold criteria. Instead, BPA stated that:

> All of the proposals developed by the three parties listed above would result in less stable rates for BPA's customers than the CRAC design presented in the initial proposal.

Lovell *et al.*, WP-02-E-BPA-40, at 12.

In relative terms, each of these proposals would require larger and more frequent rate increases after the establishment of base rates for the FY 2002-2006 rate period than BPA's CRAC design proposal.

Second, the fact that several customer groups filed testimony objecting to BPA's increase in CRAC levels from those discussed during Subscription, Hansen *et al.*, WP-02-E-PP-03, at 3-8; Saven, WP-02-E-NI-01, at 11-12; substantiates that BPA's concern for intra-period rate stability is warranted. This concern about implementation is not a trivial one.

In ROD section 6.4, Issue 2, BPA argues that it is confident that CRAC will be successfully implemented as designed, so that it is reasonable not to model the risk of its non-implementation. This argument, however, refers to the specific CRAC design BPA included in both its initial and final proposals: one employing CRAC as a relatively minor adjustment to revenues collected from base rates and characterized by annual caps that varied only slightly from those initially discussed during the development and broad regional and extraregional discussions of the Subscription Strategy. This argument is not one that BPA was applying to other CRAC designs that were characterized by annual caps far in excess of those considered during Subscription. In fact, this is the very reason that BPA, as also noted *supra*, asserted in its direct testimony that "a more robust CRAC could well be so objectionable or so onerous that BPA is effectively precluded from carrying it out as designed." BPA was legitimately concerned about the consequences of possibly having to rely heavily on year-to-year rate adjustments at levels its customers found objectionable.

BPA used three criteria to guide the development of the CRAC thresholds and annual caps to produce a proposal that reasonably balanced the use of PNRR and CRAC. CRAC was designed as a means for avoiding revenue shortfalls by adjusting revenue collection. It was never intended as the primary means of revenue recovery, and since the Subscription Strategy, BPA has consistently portrayed CRAC as a modest part of its overall risk mitigation package. The risk mitigation package presented in the final proposal meets all of the guiding criteria without supplementation, and no additional revenue-raising potential under CRAC is needed.

As noted *supra,* the proposals developed by OPUC and other parties would result in less stable rates for BPA's customers than BPA's CRAC design. Although a number of parties objected to BPA's use of intra-period rate stability as one of the guiding principles for developing its CRAC proposal, none demonstrated that BPA's decision to rely on CRAC for only a modest portion of its revenue recovery, or any of the other features in the proposal, were unreasonable given the conditions BPA faces in the upcoming rate period. Moreover, none of the other proposals displayed any features that could be considered an improvement over the BPA proposal given the agency's statutory obligations. OPUC's proposals, though well considered, were designed to use high CRAC thresholds and annual caps to achieve an additional goal that BPA does not accept: the attainment of a minimum ending reserves threshold of $500 million for FY 2006. BPA's argument for not accepting this criterion can be found in ROD section 5.4.7.1. However, even if one were to accept this additional criterion, neither of the designs OPUC presented in its direct testimony actually meet it. As noted *supra* in the evaluation of positions in issue 3 of this section, in producing its two alternative CRAC proposals, OPUC used an alternative TPP statistic that proved to be flawed, and overstated the need for PNRR and/or CRAC. When utilizing BPA's established method of calculating TPP, Example 1 resulted in a TPP of 92.6 percent, while Example 2 resulted in a 91.3 percent TPP. Lovell *et al*., WP-02-E-BPA-40, at 11. At these levels, the proposals did indeed produce a 90 percent probability of reserves levels of over $500 million, but no longer do if the examples are rerun with TPP reduced to the 88 percent level, as BPA did in its rebuttal testimony (Lovell *et al*., WP-02-E-BPA-40, at 10-12, Attachments C and E). With this correction for the faulty TPP calculation, the OPUC's CRAC designs fail to meet their additional minimum reserves criterion.

BPA's CRAC design is reasonable, and its selection for the final proposal is neither arbitrary nor capricious.

Decision

BPA has not arbitrarily and unnecessarily limited the flexibility of the CRAC.

Issue 6

Whether CRAC should rely on a rolling five-year forecast to determine by how much to raise rates, similar to the DDC mechanism.

Parties' Positions

Three parties suggested that BPA modify its proposed CRAC so that it would function in a manner more like the DDC. NEC/SOS Brief, WP-02-B-NA/SA-01, at 31; OPUC Brief, WP-02-B-OP-01, at 9-10; and CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 42. As described by NEC/SOS and OPUC:

> Our proposal is to treat low reserve levels similarly to the way Bonneville treats high reserve levels in its DDC proposal. More specifically, if reserve levels fall below a trigger level for the period, BPA would undertake a five-year forecast as outlined for the DDC. If that forecast showed a need for more revenues in order to maintain the 88 percent TPP level for the ensuing five-year period, the Administrator could raise rates as needed--capped by the market price--to bring BPA back to the 88 percent TPP level.

NEC/SOS Brief, WP-02-B-NA/SA-01, at 31. OPUC adds:

> BPA should revise the CRAC to allow the Administrator sufficient discretion to shore up end of period reserves based on a 5-year forecast of TPP. . . . The implementation of a flexible CRAC would increase, to the fullest extent possible, the likelihood that BPA will be 'well positioned' to meet a 'similarly high' TPP in the next rate period.
>
> At the least, the CRAC should include a forecasting mechanism for the Administrator to determine that the projected end of period reserves are in danger of depletion below starting reserves. The Administrator should be able to implement measures designed to recover low reserves, even if the currently proposed CRAC thresholds have not been met. In addition the Administrator should retain the discretion to raise power rates to market prices if reserves are dangerously low.

OPUC Brief, WP-02-B-OP-01, at 9-10.

CRITFC/Yakama incorporated by reference the NEC/SOS argument regarding BPA's asymmetrical and inequitable treatment of cost recovery and dividend distribution mechanisms. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 42.

In their briefs on exceptions, each of these parties reiterated their support for a rolling five-year forecast in determining the maximum levels for CRAC. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 26; OPUC Ex. Brief, WP-02-R-OP-01, at 8-9; NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 19-20.

Commenting on BPA's response in the Draft ROD, OPUC asserts:

> BPA also rejects OPUC's proposal for a 5-year rolling forecast to support the CRAC determination on the basis that it was not offered in evidence by OPUC (or the other

> parties supporting this proposal). OPUC takes exception to this finding. OPUC based this proposal solely on BPA's proposal to employ a five-year rolling forecast to determine the distribution of dividends. As OPUC stated, the argument for the rolling-five-year forecast was based on cited material contained in the record, particularly the testimony of DeWolf, *et al.*, WP-02-E-BPA-39, p. 12. OPUC's proposal is based on and supported by the rationales identified by BPA for rejecting the reverse CRAC. *See* WP-02-B-OP-01, p. 4. Thus, OPUC's proposal is supported by substantial evidence in the record.

OPUC Ex. Brief, WP-02-R-OP-01, at 8.

NEC/SOS makes an additional point on BPA's argument in the Draft ROD:

> BPA makes erroneous assumptions and then bases its conclusions on those assumptions. BPA states, "It is essential that customers signing contracts with BPA know what rates to expect for the upcoming rate period at the time they sign these contracts," in arguing against our proposal. But this is wrong. Customers may <u>want</u> to have low, flat rates – who wouldn't?- but it is not "essential." Customers will sign up with BPA as long as they can be sure the rate is the best deal in town – i.e. capped at market.

NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 19-20.

<u>BPA's Position</u>

The CRAC mechanism in BPA's 2002 rates is designed to trigger automatically based on AANR, Lovell *et al*., WP-02-E-BPA-14, at 6; with maximum planned recovery amounts of "between $125 and $150 million in FY 2001-2004 and $87.5 million in FY 2005." *Id.* at 9. The design of the CRAC is, in fact, fairly robust. *Id.* And the trigger level is substantially above the level at which BPA would have a deferral. *Id.* As noted *supra*, the design of the CRAC also recognized potential political difficulties surrounding its implementation:

> The CRAC must be designed such that political constraints do not prevent the mechanism from being implemented as modeled. A more robust CRAC could well be so objectionable or so onerous that BPA is effectively precluded from carrying it out as designed. The effect could be to shift risk to Treasury.

Lovell *et al*., WP-02-E-BPA-14, at 9.

Also, as noted *supra*, the design of the CRAC takes into account rate stability objectives. Among other criteria, CRAC thresholds and caps need to be set so to help minimize impacts on the stability of BPA's firm power rates. This means that CRAC would trigger only infrequently and with relatively minor rate increases. Lovell *et al.*, WP-02-E-BPA-40, at 10.

Evaluation of Positions

This proposal to apply a rolling five-year forecast and TPP test to the determination of annual CRAC caps was not introduced by NEC/SOS, OPUC, or CRITFC/Yakama prior to filing their initial briefs. Section 1010.11(a) of BPA's *Rules of Procedure Governing Rate Hearings* provides, in part, that "[p]arties shall be provided an adequate opportunity to offer refutation or rebuttal on any material submitted by any other party or by BPA." Further, ". . . witnesses shall submit all testimony and exhibits at the times specified in the procedural schedule." The procedural schedule for introduction of evidence in this hearing closed on February 4, 2000. BPA's rules do not provide an opportunity for parties to introduce new evidence into the record after the close of the evidentiary hearing. In addition, section 1010.13(a) of BPA's Rules of Procedure states that "[a]ll evidentiary arguments in briefs must be based on cited material contained in the record." Section 1010.13(e) discusses sanctions and provides: "The hearing officer shall not admit into the record any brief that does not conform to this section." The fact that the new CRAC proposal is based upon features of BPA's DDC design (which itself was explicitly detailed in the rate case record) is moot. Neither BPA nor other parties have had the opportunity to review this proposal, or test it through discovery and cross-examination. However, in the interest of identifying some inherent problems with this proposal, the following evaluation is offered.

It is essential that customers signing contracts with BPA know what rates to expect for the upcoming rate period at the time they sign those contracts. This is not simply a desirable but somehow unnecessary part of the ratesetting process as NEC/SOS suggest. BPA is legally obligated to let its customers know what their rates will be before the rate case is concluded and contracts are signed. While BPA's customers have, in the past, signed contracts containing, for example, variable rate provisions, these customers have had ample opportunity to be involved in the process by which these variable rates were developed. They did not have the proposed rate mechanism introduced at the eleventh hour after the opportunity for comment and rebuttal had passed.

Although BPA's CRAC design introduces some uncertainty into what customers will pay over the five-year rate period, as long as the cap on the CRAC can be specified, customers will be able to ascertain the minimum, maximum, and expected values of their rates. Employing a five-year rolling forecast to change the CRAC cap deprives customers of this opportunity when signing Subscription contracts. If CRAC is capped at market rates, but market rates are unknown or uncertain, then customers have no way of ascertaining what their expected or maximum rates might be.

The parties are arguing that BPA apply discretion to the implementation of the CRAC in a manner parallel to the discretion described in BPA's DDC proposal, but they have erred. The DDC threshold acts to trigger a distribution of dividends unless certain conditions are met; in the case of the DDC, the conditions are that a rolling five-year TPP analysis indicates the distribution would violate the 88 percent standard. Revenue Requirement Study Documentation, Volume 1, WP-02-E-BPA-02A, at 286-290. A parallel clause for the CRAC would have the CRAC threshold act to trigger a collection of additional revenue unless certain conditions are met. In the case of the CRAC, the only conditions that would be reasonably applied are that the collection of CRAC revenues would not be necessary. Thus, making the CRAC operate more like the DDC would mean less frequent, not more frequent, collections of CRAC revenue.

Decision

BPA will not use a rolling five-year forecast to set caps on CRAC. BPA's CRAC design is, in fact, fairly robust, and the trigger level is substantially above the level at which BPA would have a deferral.

Issue 7

Whether the IPTAC rate should be subject to the CRAC.

Parties' Positions

The Joint DSIs argue that the TAC in the IP rate should not be subject to CRAC. They assert that since augmentation will provide the system with fixed price purchases that will cover all risk from serving IPTAC load, there will be no residual cost uncertainty from serving the TAC load, and hence no need to apply CRAC to IPTAC. Schoenbeck *et al.*, WP-02-E-DS-03, at 4-5.

PPC notes that the IPTAC rate is based on a prediction of BPA's costs of serving these loads rather than the actual cost. This means that the IPTAC rate may not cover the risk of market prices and that CRAC may be needed to cover the risk of the necessary purchases. PPC Brief, WP-02-B-PP-01, at 17.

BPA's Position

BPA asserts that CRAC should apply to all IPTAC charges. There is no intent to create an IP rate separate from the IPTAC charges and exempt from CRAC. The reason is that BPA retains risk associated with the IPTAC load. As BPA carries all other cost and revenue risk, BPA requires the ability to adjust the IPTAC rate through a CRAC during the rate period. Lovell *et al.*, WP-02-E-BPA-40, at 15.

CRAC may be implemented for a number of reasons related to cost overruns or revenue under-runs that BPA may experience during the rate period.

Evaluation of Positions

The DSI argument fails to recognize that the IPTAC rate is based on a prediction of BPA's cost of power to serve these loads, rather than being based on the actual cost of power acquired at the time service begins. *Id.* As a result, the IPTAC rate may not recover revenues sufficient to capture all of the risks associated with purchase prices.

Further, the DSIs have not committed as yet to the amount of load they will place on BPA. Accordingly, BPA will most likely not have purchased a sufficient quantity of energy to serve all potential DSI loads by the time rates are finalized. As a result, further load and purchase risks remain. BPA needs the ability to impose the CRAC on IPTAC loads in order to manage the risk associated with serving these loads.

PPC correctly notes that the IPTAC rate is based on only a prediction of BPA's costs of serving these loads rather than the actual cost. This means that the IPTAC rate may not cover the risk of market prices and that CRAC may be needed to cover the risk of the necessary purchases. PPC Brief, WP-02-B-PP-01, at 17.

The fact is that the DSI loads have not and will not be fully committed nor fully augmented, so residual cost and revenue risks remain. These are precisely the types of risk that CRAC is established to address.

Decision

The IPTAC rate will be subject to CRAC.

7.4 Planned Net Revenues for Risk

Issue 1

Whether PNRR was set too low to result in an adequate probability of repaying Treasury.

Parties' Positions

NEC argued that BPA had incorrectly calculated TPP and offered an alternative method, which, when applied to the ToolKit data, yielded a TPP of only 79.8 percent. Weiss, WP-02-E-NA-01, at 2-4. Using this alternative definition of TPP, NEC concluded that "[a]n additional PNRR of about $46 million per year over the base case $127 million was necessary to reach that goal [of 88 percent TPP]." *Id*. at 6.

BPA's Position

Using the established method of calculating TPP, BPA determined the amount of PNRR which, together with CRAC, starting reserves, and access to the FCCF, was needed to meet the 88 percent TPP standard while keeping the rate pledge. Lovell *et al*., WP-02-E-BPA-40, at 7. For the initial proposal, that amount was $127 million. *Id.* at 7. This value was later revised to $98 million for the final proposal. Revenue Requirement Study Documentation, Volume 1, WP-02-FS-BPA-02A, at 276.

Evaluation of Positions

BPA pointed out a statistical flaw in the alternative calculation of TPP. "While this calculation would be appropriate if the events being averaged were independent and identically distributed, it is not valid to apply such a calculation to events, like the reserves values calculated in the ToolKit model, that are dependent or serially correlated." Lovell *et al*., WP-02-E-BPA-40, at 2. NEC/SOS acknowledged this flaw: "After consideration of BPA's argument, NWEC agrees that its analysis was indeed flawed." NEC/SOS Brief, WP-02-B-NA/SA-01, at 30. They further state that:

> Bonneville has presented convincing testimony that its proposed rates meet the first condition contained in its '93 policy. It has done so by establishing an objective standard--the 88 percent TPP as calculated by the ToolKit--and presenting substantial evidence to show that its proposed rates meet that standard.

Id. at 13.

See supra section 7.2 for a further discussion of this TPP calculation issue.

Decision

PNRR was not set too low to make an adequate probability of repaying Treasury. BPA was reasonable in setting the PNRR at $98 million. This amount yields a TPP of 88 percent.

Issue 2

Whether PNRR was set unnecessarily high.

Parties' Positions

The IOUs argued that "BPA should eliminate the accumulation of reserves resulting from PNRR and provide a more robust CRAC." Stauffer *et al*., WP-02-E-AC/GE/IP/MP/PL/PS-04, at 10. The IOUs also asserted that a very large CRAC would not be expected if PNRR were eliminated, *id.*; and presented a capped CRAC design with no PNRR that achieves an 88 percent TPP. Stauffer *et al*., WP-02-E-AC/GE/IP/MP/PL/PS/04, at 10. The IOUs further argue that:

> BPA's methodology shifts PNRR away from the years that cause more risk to the years that cause less risk. By proposing a DDC in connection with this unbalanced PNRR collection, BPA amasses large net revenues before they are needed and is more likely to distribute them if the DDC triggers, such that the reserves are no longer available when needed.

IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 58.

The Joint DSIs stated that "[t]he PNRR that BPA proposes for rate test period is nine times higher than the PNRR included in current rates even though BPA expects to have much higher beginning of rate period reserves than in 1996." Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 9. The Joint DSIs recommended "that BPA set its rates based on expected costs, that BPA include no PNRR in rates, and that BPA structure the Cost Recovery Adjustment Clause to achieve the 80 percent TPP." Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 10. The Joint DSIs proposed a CRAC design that employed a CRAC threshold of $675 million across all five years of the rate period with annual caps set at levels $127 million higher than BPA's proposed CRAC revenue limits. *Id.* at 11. In their brief on exceptions, the DSIs add that BPA's decision to require $127 million in PNRR is arbitrary, capricious, and contrary to law. DSI Ex. Brief, WP-02-R-DS-01, at 18.

In their brief on exceptions, Alcoa/Vanalco stated that:

> BPA never responded to the question of whether BPA has properly set the PNRR "trigger" to properly account for its risks. Alcoa and Vanalco have argued that BPA has included a rate adjustment mechanism in its power rates as a means to manage risks that may arise during a rate period.

Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 38.

BPA's Position

For the initial proposal, BPA determined that $127 million of PNRR, together with CRAC, was needed to meet the 88 percent TPP standard while keeping the rate pledge. Lovell *et al*., WP-02-E-BPA-40, at 7. This value was revised to $98 million for the final proposal. Revenue Requirement Study Documentation, Volume 1, WP-02-FS-BPA-02A, at 276.

Evaluation of Positions

Relying fully on CRAC rather than a combination of CRAC and PNRR, as the IOUs suggest, results in highly unstable rates. The average annual frequency at which the CRAC would trigger would rise from the current 12 percent to over 42 percent (and nearly two-thirds of the time by FY 2005). Rates would be hiked an average of 4.7 mills each time CRAC triggers. Stauffer *et al.*, WP-02-E-AC/GE/IP/MP/PL/PS-04, at Attachment B.

The Joint DSIs acknowledge that their proposal would trigger more frequently than BPA's proposal: "BPA's CRAC has an 11.8 percent probability that it would trigger during the rate period. The CRAC we propose has a 43.3 percent probability of triggering." Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 11. Aside from the fact that this CRAC design does not address the issue of rate stability, it also results in a TPP of only 81 percent, *id.*; which is considerably short of the 88 percent TPP target BPA has established. These were the reasons BPA rejected the proposal of Alcoa/Vanalco. The means by which BPA set its PNRR trigger involved the iterative use of its risk mitigation modeling process to determine exactly what amount of PNRR, together with BPA's CRAC proposal, would result in an 88 percent TPP. Revenue Requirement Study Documentation, Volume 1, WP-02-FS-BPA-02A, at 268-275.

Decision

The PNRR level of $98 million is not set too high but is reasonable, in combination with other risk mitigation tools, in order to assure that BPA meets the 88 percent TPP standard. The proposals developed by the IOUs and Joint DSIs to eliminate PNRR and have a more robust CRAC would result in less stable rates for BPA's customers.

Issue 3

Whether BPA's forecast of starting reserves is too low.

Parties' Positions

Both NRU and PPC argued that the starting reserves estimate for FY 2002 of $685.5 million, used in the ToolKit model for the initial proposal, was too low. NRU stated that:

> [BPA Vice President for Requirements Power Marketing Allen] Burns estimated that BPA will end FY '99 with reserves of more than $700 million . . . it is reasonable to anticipate a beginning level of reserves of $750 million rather than $685.5 million by October 1, 2001. BPA's proposal to accumulate additional reserves over anticipated starting reserves during the WP-02 rate period should be modified to reflect these improved financial results.

Saven, WP-02-E-NI-01, at 7.

PPC further asserted that:

> To date, BPA's projections have been inappropriately low estimates. Agency senior officials estimated that BPA's reserves at the end of fiscal year 1999 will stand in excess of $700 million; *see* WP-02-E-PP-03 at 11. Furthermore, there remain nineteen more months of this rate period in which BPA may accumulate additional reserves. Climatic conditions associated with wet La Niña weather patterns are expected to maintain good hydro conditions, resulting in additional revenues from sales of surplus power, which may further enhance BPA's projections of reserve levels. *Id.*

PPC Brief, WP-02-B-PP-01, at 8.

CRITFC/Yakama argue that starting reserves are too high. "Bonneville has assumed starting reserves in 2002 of approximately $685 million. This amount inappropriately includes $227 million in unspent funds under the Memorandum of Agreement . . ." CRITFC/Yakama Brief, WP-02-CR/YA-01 at 36. *See* Issue 4, *infra*.

In a footnote to their brief on exceptions, the IOUs stated, "At other places on the record BPA states it will start the next rate period with reserves of over $685 million. Tr. 643. BPA has updated its reserve estimates, but those estimates do not appear in the Draft ROD." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 39, n. 123.

BPA's Position

As BPA stated in direct testimony, it plans to update the forecast for FY 2002 starting reserves attributable to power in the studies that support the 2002 final rates. DeWolf *et al.*, WP-02-E-BPA-13, at 34. BPA's initial proposal used the forecast of ending reserves for

FY 1999 from the FY 1999 Second Quarter Review (April 1999). Lovell *et al*., WP-02-E-BPA-40, at 17. At that time, reserves were anticipated to be about $725 million at the start of the next rate period. Lovell *et al*., WP-02-E-BPA-14, at 4. This value, however, was not adjusted to account for the potential impacts of risks over the remaining two years of the current rate period. When these risks were taken into account, the average value for FY 2002 starting reserves modeled in ToolKit was $685.5 million. *Id.*

These reserves values were updated in the studies to support the 2002 final rates, using actual ending reserves for FY 1999 and a forecast of reserves from the First Quarter Review (February 2000) Lovell *et al.* WP-02-E-BPA-40, at 17. Ending reserves for FY 1999 are $665.6 million, with a much more optimistic projection for FY 2002 starting reserves of $880 million. When these values are adjusted for risk in ToolKit, the average starting reserves value for the next rate period is $842.3 million. Revenue Requirement Study Documentation, Volume 1, WP-02-FS-BPA-02A, at 272.

<u>Evaluation of Positions</u>

Although ending reserves for FY 1999 did not turn out to be as high as NRU and PPC had anticipated, the current forecast of $842.3 million (risk adjusted) for FY 2002 starting reserves is far more robust than the $750 million used by both groups in their proposals. PPC noted that:

> BPA stated that it would be updating its forecasts of starting FY 2002 financial reserves for its final rate proposal. WP-02-E-BPA-40 at 16. Fortunately, BPA has made good on that statement and its revised numbers bear out PPC's recommendations . . . BPA now reports that its ending year 1999 financial reserves are $665.6 million actual. From that, BPA forecasts that its ending year 2000 financial reserves will fall within a range from $782.5 million (based on a deterministic analysis) and $762.3 million (risk adjusted).

PPC Brief, WP-02-B-PP-01, at 8-9.

While the PPC and NRU are concerned that estimated starting reserves are too low, CRITFC/Yakama argue that starting reserves are too high. CRITFC/Yakama argue that starting reserves should not include MOA carryforward funds, and that these funds are being double counted. CRITFC/Yakama argue that the estimate of starting reserves should be reduced by the amount of the MOA carryforward balance. CRITFC/Yakama Brief, WP-02-B-CR/YA-01. *See* Issue 4 *infra* for a discussion of double-counting issues.

BPA updates its forecasts quarterly, so the revision of reserves values was done as a matter of routine. However, as BPA noted, both NRU and PPC assumed that there was no risk in the remaining years of the current rate period for the ToolKit modeling that underlies its proposal. Lovell *et al.*, WP-02-E-BPA-40, at 12.

This final forecast of reserves is driven by actual reserves for FY 1999 ($665 million), updated program budgets for FY 2000 and FY 2001, and an updated revenue forecast based on an "early bird" snow pack estimate for water year 2000. This "early bird" snow pack estimate may reflect the La Niña weather pattern referred to by PPC; however, BPA will not be relying on the potential impact of La Niña. BPA will be relying instead on a forecast based upon the actual snow pack. During cross-examination of the revenue requirement panel, DeWolf *et al*., WP-02-E-BPA-13 and 39, Mr. Thor was asked about the runoff forecast. Mr. Thor noted that the January mid-month forecast was 109 million-acre feet (maf) runoff for The Dalles. He also noted that the average runoff for The Dalles is 103 maf. He continued, "So the important point is that we're a little bit above average at this point in the forecast for this year." Tr. 693-94. So far, there is no evidence that this will be a La Niña year.

The IOUs state that BPA did not update the reserve forecast in the Draft ROD. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 39, footnote 123. BPA did update the forecast in the Draft ROD. Draft ROD, WP-02-A-01, at 7-32.

<u>Decision</u>

BPA will use actual ending reserves for FY 1999 and a forecast of reserves from the First Quarter Review (February 2000) in the studies supporting the 2002 final rates. It is reasonable to adjust these numbers for risks remaining in the current rate period. BPA's forecast of starting reserves is not too low.

<u>Issue 4</u>

Whether BPA is double-counting the MOA carryforward funds in the starting reserves balances for FY 2002.

<u>Parties' Positions</u>

CRITFC/Yakama argue that BPA is double-counting the MOA carryforward funds. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 38. CRITFC/Yakama recommend that "Bonneville reduce its starting reserve by $227 million to avoid double-counting the unexpended MOA funds." *Id*. at 40. CRITFC/Yakama argue that "BPA cannot use a dollar for fish and wildlife restoration that has been unexpended under the MOA and committed to fish and wildlife funding after 2002 . . . and assume that the same dollar is available for other risks and uncertainties facing Bonneville." CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 27.

UCUT argues that "[t]his rolling forward of program measures [from the current rate period to FY 2002-2006] and inclusion of unexpended fish and wildlife funds as starting reserves is inconsistent with the 1996 MOA and carries the risk that such funds, if reallocated and expended under the MOA, will not be available as starting reserves." UCUT Brief, WP-02-B-UC-01, at 22. UCUT also notes that "BPA is planning to update the forecast of FY 2002 starting reserves attributable to power in final proposal studies. BPA has stated that starting reserves are treated in the rate proposal as one of the tools to mitigate risk. Overestimating starting reserves counters any risk mitigation effect." *Id*.

BPA's Position

BPA is not double-counting the MOA carryforward funds and, consistent with the MOA, BPA is making an amount equivalent to the carryforward funds balance available for fish and wildlife expenditures after FY 2001. Lovell *et al*., WP-02-E-BPA-40, at 19.

Evaluation of Positions

CRITFC/Yakama contend that BPA is double-counting the MOA carryforward funds because "Bonneville has counted the unexpended fish and wildlife funding as part of the reserves. It has also counted these reserves as one of the contingencies to cover the full range of uncertainties facing Bonneville." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 38. UCUT alleges that ". . . inclusion of unexpended fish and wildlife funds as starting reserves is inconsistent with the 1996 MOA . . ." UCUT Brief, WP-02-B-UC-01, at 22. CRITFC/Yakama and UCUT argue that BPA is double-counting the MOA carryforward by including it in starting reserves, and therefore available to mitigate risks, and by also making the carryforward available for fish and wildlife purposes. CRITFC/Yakama and UCUT both recommend that BPA lower the estimate of starting reserves by the amount of the carryforward balance. CRITFC/Yakama, WP-02-B-CR/YA-05, at 40; UCUT Brief, WP-02-B-UC-01, at 22. They argue that by reducing the starting reserves by the amount of the carryforward balance, BPA will be able to make the funds available for fish and wildlife purposes.

In 1996, a Fish & Wildlife MOA was established to stabilize BPA's fish and wildlife obligations over a six-year period, FY 1996 through FY 2001. 64 Fed. Reg. 44318, 44320 (1999). The MOA also established a methodology for calculating the carryforward balance. Lovell *et al*., WP-02-E-BPA-40, at 17. In accordance with the provisions of the MOA, BPA calculates a cumulative carryforward balance at the beginning of each year. *Id*. BPA also includes an interest credit on these carryforward balances. *Id*.

BPA intends to make the MOA carryforward funds available for fish and wildlife purposes, even if reserves are reduced from the current forecast for FY 2001:

> Q. Assuming Bonneville faces some disastrous problems in the year 2002 or shortly thereafter, such as low market prices or low water, combination of events that are non-fish and wildlife problems, and these events deplete Bonneville's reserves to an extremely low level, let's say zero, what will become of the MOA funds that are in Bonneville's reserves?
>
> A. (Dr. Lovell) That would not affect Bonneville's commitment to adhere to the principles and make funding in the amount of the MOA carryforward available for fish and wildlife purposes.
>
> Q. Can you explain how those MOA funds would still be available?
>
> A. (Dr. Lovell) I'm using the word "fund" pretty [carefully], not to mean particular dollars that are in the reserve. As I indicated, Bonneville is planning to spend a great deal of money on fish and wildlife throughout the

> [2002-2006] rate period. Not all of that funding comes from reserves; some of it is in the revenue requirement.
>
> Q. But we are --
>
> A. (Dr. Lovell) The amount of funding being made available for fish and wildlife is in the next rate period greater than the MOA carryforward.
>
> Q. Correct. But I am speaking only of the MOA funds that are being included in Bonneville's reserves. Would your answer be the same for just those funds?
>
> A. (Dr. Lovell) As I said, my understanding of the MOA is not that it requires that a particular dollar that ends up in the reserves due to circumstances that lead to the existence of a carryforward calculation be set aside in some separate place for fish and wildlife. The requirement is that Bonneville will make available for fish and wildlife purposes funding of an amount as large as the MOA carryforward calculation. And Bonneville is going to do that.

Tr. 723-25.

BPA is not double-counting the carryforward funds, and consistent with the MOA, it is making an equivalent amount to the carryforward funds balance available for fish and wildlife expenditures after FY 2001. Lovell *et al*., WP-02-E-BPA-40, at 19. BPA explained that:

> BPA has included in annual revenue requirements for FY 2002-2006 the weighted average annual expenses of the 13 Alternatives in the Principles. These expenses are reflected in BPA F&W operations and maintenance (O&M), U.S. Army Corps of Engineers (COE) O&M, and the Bureau of Reclamation O&M, capital recovery expenses, and balancing and system augmentation purchases. *See* DeWolf, *et al.*, WP-02-E-BPA-13, at 8. Rates are being set to generate annual revenues sufficient to recover these and other annual expenses in revenue requirements, plus planned net revenues. In this way, annual revenues are set to cover the weighted average of F&W costs in the 13 Alternatives without a reliance on the carryforward balance.
>
> The forecast of starting reserves includes all projected cash in the BPA fund, a portion of which is attributable to the carryforward balance…
>
> As explained [] below, some activities that were assumed in the MOA to be funded in FY 1996-2001 have been rolled forward and included in costs projections for some of the 13 Alternatives for the FY 2002-2006 rate period. Further, an amount of funding equivalent to the carryforward balance is projected to be available post-2001 by reason of the fact that F&W costs in revenue requirements are substantially greater than the carryforward balance. Indeed, F&W costs for the first two years of the new rate period are greater than the carryforward estimate.

Lovell *et al*., WP-02-E-BPA-40, at 19-20.

As BPA noted, not all of the capital recovery expenses require cash. The depreciation portion does not require cash. Lovell *et al*., WP-02-E-BPA-40, at 21. As a result, only the portion of the carryforward balance that is the difference between the projected and actual cash expenditure is in the "bank" right now (*i.e.,* cash reserves). *Id*. The depreciation amount is not in reserves, because depreciation is a noncash expense. Therefore, an underrun in depreciation expense does not mean that cash has been saved. *Id*.

Starting reserves, together with PNRR, CRAC, and access to the FCCF, are treated in the 2002 power rates as tools to mitigate risks, including fish and wildlife costs risks, such that all costs are recovered on time and in full. *Id.* at 19. BPA would have a double-counting problem if it withheld the carryforward balance from starting reserves, because funding for FY 2002-2006 fish and wildlife costs is already provided in annual revenue requirements by reason of the weighted average expenses of the 13 Alternatives and by reason of our risk mitigation tools (including starting reserves). *Id.* at 20.

BPA has stated that it will fund all of its fish and wildlife expenses in the next rate period. *See* Hansen *et al*., WP-02-E-PP-09, Attachment B at 1: BPA White Paper, *Fish and Wildlife Funding for the 2002-2006 Rate Period*. It is possible that BPA will use the unexpended MOA funds to meet fish and its wildlife expenses in the FY 2002-2006 period; however, fish and wildlife expenses are just one of the risks that BPA will be facing in that period.

BPA is setting rates to recover the equally weighted costs of the 13 Alternatives. *See* ROD section 5.4.4, *supra.* By asking BPA to withhold the projected MOA carryforward balance from starting reserves, CRITFC/Yakama are effectively asking BPA to augment the costs of the 13 Alternatives. While BPA has stated that it will meet all of its fish and wildlife expenses in the 2002-2006 rate period, asking BPA to increase the amount being considered is outside the scope of this proceeding. *See* ROD section 5.3.2, *supra*. BPA cannot set aside dollars in reserves for a particular cost. PPC also noted that "we are not aware of any mechanism in which BPA could legally 'earmark' funds for a specific purpose, such as fish and wildlife, within its single Bonneville fund, for carryover from one rate period to the next." Hansen *et al.*, WP-02-E-PP-09, at 18.

While arguing for lower starting reserves, CRITFC/Yakama argue that BPA should set rates to assure an 88 percent TPP for Alternative 13u. *See* ROD section 5.4.6, *supra.* CRITFC/Yakama's argument that BPA should reduce starting reserves by the amount of the projected MOA carryforward balance and set rates to cover high cost alternatives is inherently unfair to ratepayers.

PPC also noted that "[w]e accept BPA's obligation to spend unused funds on fish and wildlife, but we do not agree that BPA has erred in counting unused funds in its starting reserves or that BPA is double-counting the funds as alleged in WP-02-E-CR/YA-02 at 9." Hansen *et al.*, WP-02-E-PP-09, at 18.

Decision

BPA has appropriately included the MOA carryforward funds balance in the starting reserves balance for 2002 and is not double-counting those funds.

Issue 5

Whether BPA has underfunded its fish and wildlife program responsibilities in the current rate period, thereby not making funding available as called for under the MOA.

Parties' Positions

CRITFIC/Yakama argued that "Bonneville has ended up obligating less than the $127 million available under the MOA each year. This has added to the annual carryforward." Sheets *et al*., WP-02-E-CR/YA-05, at 22. They also argued that "[t]he carryforward balance for the direct budget category arises because Bonneville has chosen to under-fund its fish & wildlife responsibilities each year . . ." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 39.

CRITFC/Yakama argued that "Bonneville worked with some members of the Congressional Delegation to undermine the MOA by supporting an appropriation rider to the Northwest Power Act." CRITFC/Yakama Ex. Brief, WP-02-E-CR/YA-01, at 27.

CRITFC/Yakama argued that BPA uses different and inconsistent interpretations of the Northwest Power Act to serve its purposes. CRITFC/Yakama Ex. Brief, WP-02-E-CR/YA-01, at 28.

BPA's Position

The MOA was developed to establish BPA's financial commitment for Columbia River fish and wildlife mitigation. The carryforward balance has grown primarily because the capital recovery expenses have not been as high as forecast under the MOA. Lovell *et al*., WP-02-E-BPA-40, at 21. BPA set rates in 1996 to carry out the terms of the MOA in order to make the funding available for expenditure. *Id.* at 23. BPA has funded all projects that were recommended by the Northwest Power Planning Council. The carryforward has resulted from a number of factors described elsewhere. *Id.*

Evaluation of Positions

CRITFC/Yakama argue that a portion of the carryforward balance results from BPA underfunding its fish and wildlife program. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 39. The $127 million amount cited is the sum of BPA's direct program O&M and BPA investment in fish and wildlife as projected by the MOA.

CRITFC/Yakama allege that BPA worked with members of the Northwest Congressional delegation to undermine the MOA with an appropriations rider to the Northwest Power Act. CRITFC/Yakama Ex. Brief, WP-02-E-CR/YA-01, at 27. While BPA may have been consulted during the development of the appropriations rider referred to, BPA did not in any way "seek to undermine the MOA." There is no evidence on the record to support these allegations. Therefore, there is no way for BPA to address this kind of argument.

BPA set rates in 1996 to carry out the terms of the MOA in order to make the funding available for expenditure. Lovell *et al*., WP-02-E-BPA-40, at 23. BPA has made the funding available as called for under the MOA. At the time of the initial proposal, the projected carryforward balance for FY 2001 was $203 million. Of this amount, $182 million was related to capital fixed expenses (capital recovery expenses, that is, interest and depreciation). *Id.* at 21. The remainder of the carryforward balance relates to BPA's direct program. BPA has funded all projects that were recommended by the Council. At the end of FY 1999, the projected MOA carryforward balance for FY 2001 was $248 million.

In their brief on exceptions, CRITFC/Yakama confuse the overall Council Program discussed in ROD section 5.3.2, *supra,* and BPA's position discussed here. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 28. BPA has funded specific projects that have gone through the Council's review process.

The capital recovery expenses, interest and depreciation, are lower than forecast in the MOA because there is a lower amount of repayable appropriations being charged interest and a lower level of assets being depreciated. *Id*. at 23. This is fundamentally the cause behind the carryforward balance. These expenses are lower than projected because there have been lower Congressional appropriations than expected under the MOA and because the COE has placed less investment in service than forecast under the MOA. *Id*. at 22. CRITFC/Yakama noted that "[a]ppropriations for capital construction programs of the Corps of Engineers Columbia River Fish Mitigation Plan have not kept pace with the budget projected in the MOA . . . The House Energy and Water appropriations subcommittee also has been critical of the Corps proposed capital investments." Sheets *et al*., WP-02-E-CR/YA-05, at 23. The projected 2001 carryforward is not primarily attributable to BPA direct program fish and wildlife O&M nor to BPA's capital investment. Lovell *et al.*, WP-02-E-BPA-40, at 23. Those costs have been lower than the MOA levels, not because BPA's program levels are lower, but because Congressional appropriations and COE plant in service have been lower.

Not all of the capital recovery expenses require cash; in particular, the depreciation portion does not require cash. Lovell *et al*., WP-02-E-BPA-40, at 21. As a result, only the portion of the carryforward balance that is the difference between the projected and actual cash expenditure is "in the bank" right now (*i.e.,* cash reserves). *Id*. The current carryforward balance forecast for the end of FY 1999 is $203 million, of which $175 million is cash that is "in the bank" now. *Id.* At the end of FY 1999 the carryforward balance is $215 million.

<u>Decision</u>

BPA has set rates to recover the costs of the MOA in 1996. Those costs have been lower than the MOA levels, not because BPA's program levels are lower, but because Congressional appropriations and COE plant in service have been lower. BPA has made the funding called for under the MOA fully available.

Issue 6

Whether any MOA carryforward balance at the end of FY 2001 is to be made available for fish and wildlife expenditures above and beyond the fish and wildlife program expenditures planned in the rate case for the FY 2002-2006 rate period.

Parties' Position

CRITFC/Yakama argue that the 13 Alternatives assume that certain projects would have already occurred before the end of the period covered by the MOA and that the CBFWA budgets were assumed to be in addition to the funds committed in the MOA. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 38.

The PPC stated that it did not see "any language that obligates BPA to any specific, or additional spending beyond the current rate period. While BPA cannot redirect unspent funds elsewhere, the MOA does not create any right to increased levels in the future." Hansen *et al*., WP-02-E-PP-09, at 18.

BPA's Position

There are some fish and wildlife investments that the MOA anticipated would be completed by FY 2001 that are now included in the 13 Alternatives for FY 2002-2006. Lovell *et al*., WP-02-E-BPA-40, at 20. The Principles make no mention that BPA should assume that fish and wildlife costs in FY 2002-2006 will be augmented by the amount of the carryforward balance, even if funded by the carryforward balance. In fact, BPA may be prevented from doing so legally. *Id*. BPA set rates in 1996 to make funding available for expenditures under the terms of the MOA. The carryforward resulted from a number of factors described *supra*. *Id.* at 23. The costs of the 13 Alternatives in the FY 2002-2006 revenue requirements exceed the amount of the carryforward.

Evaluation of Positions

There are some fish and wildlife investments in the MOA that were expected to be completed before FY 2002 that are now included in the 13 Alternatives for FY 2002-2006. Lovell *et al*., WP-02-E-BPA-40, at 20. For example, in the assumptions for the MOA, surface bypass collectors were to be put into service by FY 2001. These investments have not been completed, and several of the 13 Alternatives include surface bypass investment for the FY 2002-2006 rate period. *Id.* Another capital investment assumed in the MOA was engineering and design for drawdown on the lower Snake River projects. Of the 13 Alternatives, seven incorporate various levels and combinations of drawdown at the lower Snake River and John Day projects. *Id.*

BPA stated that the Principles make no mention of BPA assuming that the fish and wildlife costs in FY 2002-2006 will be augmented by the amount of the carryforward balance, even if funded by the carryforward balance. In fact, BPA may be prevented from doing so legally. Lovell *et al*., WP-02-E-BPA-40, at 20. Further, "BPA has a single account at the U.S. Treasury, the BPA Fund, into which all revenues are deposited and from which all expenditures are made.

Cash may not be held out or segregated in the Fund without risk of violating priority of payments and other requirements. The MOA does not specify the disposition of carryforward funds post FY 2001, [except] to say that the carryforward funds will not be reprogrammed to purposes other than fish and wildlife recovery and they will remain available for fish." *Id.*

As explained above, BPA is not reprogramming the carryforward balance to non-fish and wildlife uses. Indeed, amounts well in excess of the carryforward balance are being made available for fish and wildlife expenditure after FY 2001, by reason of the fact that the MOA carryforward is estimated at $227 million, and average annual expenses in revenue requirements exceed $400 million. Lovell *et al*., WP-02-E-BPA-40, at 21. In rebuttal testimony, the PPC stated that it did not see "any language that obligates BPA to any specific, or additional spending beyond the current rate period. While BPA cannot redirect unspent funds elsewhere, the MOA does not create any right to increased levels in the future." Hansen *et al*., WP-02-E-PP–09, at 18.

BPA is not establishing a fish and wildlife budget for 2002-2006 period in this rate proceeding. The Principles do not establish a budget for this period. *See* Revenue Requirement Study Documentation, Volume 1, WP-02-E-BPA-02A, Chapter 13, Attachment 1, Principles. While the unexpended MOA funds are not in addition to budgets for the 2002-2006 period, BPA has stated that it will meet all of its financial obligations, including funding for Northwest fish and wildlife, for the FY 2002-2006 rate period. *See* Hansen *et al*., WP-02-E-PP-09, Attachment B, at 1: BPA White Paper, *Fish and Wildlife Funding for the 2002-2006 Rate Period*.

Decision

The MOA did not require that any MOA carryforward balance be made available for fish and wildlife expenditures above and beyond those included in the FY 2002-2006 rate case.

Issue 7

Whether the MOA carryforward balance demonstrates that BPA is over-collecting revenues in relation to its total fish and wildlife program expenditures.

Parties' Position

Alcoa/Vanalco/Energy Services stated that "[i]t would appear that current rates are overcollecting revenue in relation to total program expenditures for each year of the rate period. This is exemplified by what appears to be a substantial cash carryforward balance for fish and wildlife expenditures for every year since 1996, and is projected to continue through the end of the rate period in 2001." Speer *et al*., WP-02-E-AL/VN/EG-02, at 12.

CRITFC/Yakama state that:

> in FY 97 and each subsequent year, CBFWA has identified about $150 million needed to fund core projects to implement the F&W Program. In addition, Bonneville has ended up obligating less than the $127 million available under the MOA each year. This has added to the annual carryforward. The carryforward balance for the direct budget category arises because Bonneville has chosen to

> under-fund its fish & wildlife responsibilities each year, not because it is over collecting revenues.

Sheets *et al.*, WP-02-E-CR/YA-05, at 22.

BPA's Position

BPA stated in rebuttal that the carryforward does not indicate that BPA is overcollecting. BPA set rates in 1996 to carry out the terms of the MOA in order to make the funding available for expenditure. The carryforward has resulted from a number of factors described elsewhere. Lovell *et al.*, WP-02-E-BPA-40 at 23.

Evaluation of Positions

Alcoa/Vanalco/Energy Services argued that the fact that there is a carryforward balance indicated that BPA was over-collecting. Speer *et al.*, WP-02-E-AL/VN/EG/-02, at 12. Contrary to what Alcoa/Vanalco/Energy Services asserted, CRITFC/Yakama argued that the carryforward balance results because "Bonneville has chosen to under-fund its fish & wildlife responsibilities each year, not because it is over collecting revenues." Sheets *et al*., WP-02-E-CR/YA-05, at 22. *See* Issue 5 for discussion of this issue.

The carryforward balance does not indicate that BPA is overcollecting. BPA set rates in 1996 to carry out the terms of the MOA and make the funding available for expenditure. Lovell *et al*., WP-02-E-BPA-40, at 23. The source of the carryforward is for reasons beyond BPA's control and is documented in Issue 5 *supra*. Since the carryforward is not being held out from starting financial reserves, it is available to mitigate risk, including fish cost uncertainty. *Id.* Starting reserves also include interest earnings on the higher reserves.

BPA has funded all projects recommended by the Northwest Power Planning Council. It is the Northwest Power Planning Council, not the CBFWA, that by statute recommends to BPA its program for funding. CBFWA works through the Council's prioritization process to recommend its priorities for fish and wildlife funding.

Decision

BPA has not been overcollecting revenues in relation to its total fish and wildlife program expenditures, and the existence of a MOA carryforward balance does not indicate that BPA has been doing so.

7.5 Dividend Distribution Clause

Issue 1

Whether BPA should revise the DDC threshold level of $250 million in AANR (equivalent to $950 million in reserves).

Parties' Positions

PPC states that BPA's DDC triggers at too high a level of reserves and does not act as "an assured brake to slow BPA's accumulation of reserves when BPA enjoys the benefit of prosperous financial times." PPC Brief, WP-02-B-PP-01, at 19. PPC proposes an automatic distribution based on a DDC threshold of $850 million in reserves. *Id*. PPC's recommended reverse CRAC "would refund revenues to customers subject to the CRAC when BPA's financial reserves exceed $850 million. The maximum amount of money that could be returned in a given year under the reverse CRAC would be capped. The purpose of the cap is to ensure that the expected average reserves at the end of the rate period would also be $850 million." Hansen *et al*., WP-02-E-PP-03, at 9-10.

CRITFC/Yakama assert that BPA should be able to build reserves to whatever level is necessary to ensure fulfillment of BPA's fish and wildlife obligations and payments to Treasury, CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 4; and take exception to NRU's arguments that any reserves over $1 billion creates an attractive nuisance for extraregional interests. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 29. They oppose the DDC and BPA's reduction of the DDC threshold from $500 million in AANR, proposed in the initial proposal, to $250 million in AANR, in rebuttal testimony. *Id*. They advocate that if BPA retains the DDC, the threshold should be increased to $1.6 billion (in reserves) to better enable BPA to meet its future obligations and remain competitive with market rates. *Id*.; CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 29. UCUT also disagrees with BPA's DDC threshold reduction and "requests that, due to extraordinary risks taken, the DDC be triggered only after the original reserve level (of $500 million) is collected." UCUT Brief, WP-02-B-UC-01, at 26.

BPA's Position

BPA's DDC mechanism would return to as-yet unspecified stakeholders amounts above the DDC threshold that are not needed to fulfill an 88 percent TPP on a rolling five-year forecast basis. The DDC threshold is the minimum level of AANR that must be realized before a dividend distribution is considered. Revenue Requirement Study Documentation, Volume 1, WP-02-FS-BPA-02A, at 287. The threshold triggers a review of the forward-looking cash requirements and cash in excess of that needed to meet the TPP. Initially, BPA set the DDC threshold at $500 million in AANR, equivalent to $1.2 billion in reserves, which represents about a 32 percent average annual probability of triggering. DeWolf *et al*., WP-02-E-BPA-39, at 12. In rebuttal testimony, BPA reduced the threshold to $250 million in actual accumulated net revenues, equivalent to $950 million in reserves. This increases the annual average probability that the DDC threshold will be reached to 44 percent. *Id*. BPA made the policy choice to reduce the threshold to a $950 million trigger level based on consideration of three criteria: (1) it falls below the $1 billion amount identified earlier by the region's Congressional delegation, as a threshold for being an "attractive nuisance" for extraregional interests; (2) by reducing the threshold, BPA is forced to review its five-year projections more often, thereby giving customers a more frequent chance to review the logic behind BPA's reserve requirements; and (3) the new $950 million threshold is close to the highest level of reserves BPA has attained, so a review is appropriate as we move to build reserves. DeWolf *et al*., WP-02-E-BPA-39, at 13. It is BPA's position that cash not be retained if it is not needed for the TPP test. *Id*.

As noted in ROD section 7.3, Issue 1, *supra*, for the final proposal, BPA recalculated the AANR-based CRAC and DDC thresholds based upon updated reserves and net revenue forecasts. This resulted in slightly revised threshold values, which were rebased to end-of-year FY 1999 actuals. The DDC would trigger when AANR rose above $250 million. The derivation of these values is presented in the Revenue Requirement Study Documentation, Volume 1, WP-02-FS-BPA-02A, Chapter 12, Appendix 1.

Evaluation of Positions

PPC's argument for lowering the DDC threshold to $850 million is based on their modified ToolKit run, which includes a reverse CRAC cap that would ensure average ending reserves of $850 million at the end of the rate period. Hansen *et al*., WP-02-E-PP-03, at 10. On the other hand, UCUT argues that the threshold should be raised back to the initial proposal threshold level of $1.2 billion. UCUT Brief, WP-02-B-UC-01, at 26. CRITFC/Yakama argue that the threshold should be raised even higher to $1.6 billion, to allow BPA to meet future obligations and remain competitive with projected market rates. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 40. UCUT proclaims that "BPA must be able to fund Fish and Wildlife in the next rate period and make Treasury payments without exceeding the market price of power." UCUT Brief, WP-02-B-UC-01, at 21.

The DDC is designed to distribute cash in excess of the threshold that is not needed to meet the five-year forward-looking TPP test. In its rebuttal testimony, BPA made a policy judgement to lower the threshold from $500 million in AANR to $250 million in AANR (equivalent to $1.2 billion in reserves to $950 million in reserves) because the ToolKit modeling suggested that the TPP test could still be met with a lower threshold. DeWolf *et al*., WP-02-E-BPA-39, at 13. In lowering the threshold to $950 million, BPA took into consideration the $1 billion amount identified as an "attractive nuisance" for extraregional interests, Saven, WP-02-E-NI-01, at 8; the checks and balances due to increase in frequency of BPA's five-year public review, and historical precedents for highest level of reserves. DeWolf *et al*., WP-02-E-BPA-39, at 13. BPA's position is that cash should not be retained if it is not needed to mitigate risks. *Id*.

Further lowering the threshold below $950 million may jeopardize BPA's ability to fulfill its financial obligations and Principle No. 4. Raising the threshold, as CRITFC/Yakama and UCUT suggest, is unnecessary to assure the ability to meet future obligations, because of the forward-looking five-year TPP test BPA would be required to perform and subject to public review before any distributions. If the threshold is too high, BPA may end up retaining reserves in excess of what it needs to recover costs. The $1.6 billion threshold targeted by CRITFC/Yakama represents an obsolete DDC threshold level that BPA developed in the early stages of preparation and analysis for the rate case, prior to BPA's initial proposal. CRITFC/Yakama provided no convincing logic or support for its position that the threshold should be at $1.6 billion. Its assumptions regarding risks and risk mitigation tools are no longer valid in this rate case. During the pre-rate case TPP testing period, the $1.6 billion threshold resulted in a 30-40 percent probability of holding cash in excess of BPA's needs. Increasing the threshold to amounts greater than what BPA proposed in its initial proposal may jeopardize its compliance with subsection 7(n) of the Northwest Power Act, which states that BPA shall set rates to recover costs not to exceed such amounts the Administrator forecasts will be expended during the 2002-2006 rate period (though preserving the Administrator's ability to establish appropriate reserves and maintain a high TPP for the subsequent period). *See* ROD section 7.2 for a discussion of the 7(n) issue.

Decision

BPA will set the DDC threshold at $250 million in AANR (equivalent to $950 million in reserves). Distributions will not be made below this threshold.

Issue 2

Whether BPA should replace the DDC with a "reverse CRAC."

Parties' Positions

Several parties argue that BPA should replace the DDC with a "reverse CRAC."

PPC alleges that BPA's DDC has several inherent flaws. They claim that "the DDC provides no assurance that monies collected in excess of the agency's revenue requirement will be returned to those customers who made the overpayment in the first place." PPC Brief, WP-02-B-PP-01, at 19; PPC Ex. Brief, WP-02-R-PP-01, at 5. PPC argues that the distribution of excess reserves will be "to an unknown group of stakeholders, and "only after the BPA Administrator deigned to pay out such a dividend." PPC Brief, WP-02-B-PP-01, at 19; PPC Ex. Brief, WP-02-R-PP-01, at 4. PPC also argues that the DDC "does not act as an assured brake to slow BPA's accumulation of reserves when BPA enjoys the benefit of prosperous financial times." *Id*. PPC proposes that BPA adopt a reverse CRAC that would automatically trigger refunds to customers who are subject to the CRAC when reserves exceed $850 million. Annual refunds would be capped at $140 million or $155 million per year (depending on whether or not BPA modifies the CRAC as PPC suggests or retains the CRAC presented in the initial proposal). PPC Brief, WP-02-B-PP-01, at 20; PPC Ex. Brief, WP-02-R-PP-01, at 5.

OURCA favors the concept of distributing excess reserves, and also supports PPC's proposal for a reverse CRAC that it claims would equitably allocate excess monies to customers who are subject to the risks of a rate increase through the CRAC mechanism. OURCA Brief, WP-02-B-OU-01, at 4.

NRU proposes replacing the DDC with a discretionary reverse CRAC. NRU accepts BPA's revised proposal that the threshold be set at $950 million in reserves and that amounts in excess of the five-year, 88 percent TPP standard be distributed based on a financial forecast and risk analysis conducted at the time the DDC threshold is crossed. However, the NRU proposes that all distributions take the form of refunds to customers based on their contributions to the excess reserve amounts. This would obviate the need for BPA's proposed public process on dividing and allocating dividends. NRU Brief, WP-02-B-NI-02, at 10-11. NRU's rationale for the discretionary reverse CRAC is based on "the need to align the risks and benefits of the FCRPS with the customers who pay for the system, . . . that the DDC is not a 'sound and businesslike mechanism for redistributing excess revenues for various reasons, including that the customers' excess rate money may end up going to non-customer "stakeholders," and that the process for allocating funds will be divisive and political." NRU Brief, WP-02-B-NI-02, at 9. NRU claims that "BPA's rejection of NRU's proposed Discretionary Reverse CRAC is not justified by evidence in the record." NRU Ex. Brief, WP-02-R-NI-01, at 4.

NRU argues that BPA's statutory obligations mandate that BPA operate on the basis of only recovering its costs. If BPA overrecovers its costs, then those monies should be returned back to the ratepayers (customers) based on a statutory covenant that precludes BPA from charging customers for more than its costs. NRU Brief, WP-02-B-NI-02, at 12; NRU Ex. Brief, WP-02-R-NI-01, at 4. NRU's proposal is no different than BPA's revised DDC, except that ". . . instead of a potentially divisive process for redistributing excess revenues, BPA would implement distributions through a discretionary Reverse CRAC mechanism . . . This would be a much more predictable and fair mechanism." *Id*. NRU states that its earlier argument that the DDC is a poor mechanism for distributing excess revenues remains unrebutted. *Id*. at 10.

NEC/SOS support BPA's "flexible and business-like approach" to implementing the DDC, as long as the Administrator maintains the discretion of triggering a distribution based on future costs and needs. NEC/SOS Brief, WP-02-B-NA/SA-01, at 25-26. This provides a check on BPA's building up unneeded excess reserves while allowing BPA the ability to mitigate foreseeable financial challenges. *Id*. NEC/SOS argue that the disparity in design between the DDC and the CRAC (capped recovery amounts and automatic trigger) wrongly places customers' interests above the interests of Treasury. *Id*. at 29. The CRAC should function like the DDC, meaning that there should be no arbitrary caps, and recovery amounts should be determined by cash requirements to meet the 88 percent TPP goal based on a five-year financial forecast and risk analysis. "There are powerful arguments for maintaining the flexibility in the DDC concept rather than the 'unduly rigid and mechanistic' and 'inflexible formulaic' approach in both PCC/NRU's Reverse CRAC and BPA's CRAC proposal." NEC/SOS Brief, WP-02-B-NA/SA-01, at 25, 27.

CRITFC/Yakama "oppose PPC's proposal to reduce the Administrator's discretion in implementing the DDC" and supports BPA's proposal for a five-year forecast and review of future costs before the Administrator decides on implementing the DDC. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 40-41.

The IOUs argue that "the inclusion of BPA's proposed DDC and capped CRAC together increase the potential for cost shift to transmission customers. BPA may well develop enough revenues early in the rate period to trigger a refund . . . for the subsequent year, BPA could project a level of financial reserves that causes it to trigger the CRAC . . . In sum, these events would increase the potential of inequitable shifting of BPA power costs." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 58. The IOUs further contend that "proposing a DDC in connection with (this) unbalanced PNRR collection, BPA amasses large net revenues before they are needed and is more likely to distribute them if the DDC triggers, such that the reserves are no longer available when needed . . . since the DDC is not included in BPA's model, any distributions that occur are not modeled, resulting in the model overstating the funds available to pay Treasury and hence overstating the TPP." *Id*. at 59.

In their brief on exceptions, the DSIs argue that BPA's decision to implement a DDC is arbitrary, capricious, and contrary to law. DSI Ex. Brief, WP-02-R-DS-01, at 18. The DSIs state that BPA has no authority to overcharge its customers, and then, if it chooses, dole the money out selectively to entities other than those that were overcharged. *Id.*

BPA's Position

For the purpose of setting rates for FY 2002-2006, BPA has set as its cost recovery goal the 88 percent TPP established in the Principles. "There is substantial 'upside uncertainty' that may cause net revenues to accumulate at levels higher than our cost recovery goal . . . If hydro, market price, and other risks do not materialize, and costs are not significantly higher or revenues significantly lower than planned, BPA's generation function may accumulate reserves in excess of its long-term needs." DeWolf *et al*., WP-02-E-BPA-39, at 10. For this reason, BPA has designed the DDC to distribute cash reserves in excess of BPA's needs to meet the TPP goal. The DDC proposal calls for an analytical test to determine whether and how much to distribute. DeWolf *et al*., WP-02-E-BPA-39, at 20. This five-year, forward looking 88 percent TPP test, not the Administrator's judgment, is the basis for determining the amount of the dividend. *Id.*

BPA's uncertainties and risks are great. The reverse CRAC espoused by PPC is unduly rigid and mechanistic, and offers little flexibility or adaptability to changing costs and risks. DeWolf *et al*., WP-02-E-BPA-39, at 15. Automatically distributing cash in excess of a reserve threshold without testing for BPA's financial need could jeopardize Treasury payments in a situation where BPA knows that high costs lie ahead. It is not sound business practice to rebate money shortly before that money will be needed. The reverse CRAC fails to meet the requirements of Principle No. 4 because it includes no consideration of prevailing TPP and no option to recalibrate the amount that is rebated as risk and cost conditions change. *Id.*

BPA proposed that it would decide on "dividing and allocating" dividends among stakeholders in a public consultation process that would occur before the next rate period begins. DeWolf *et al*., WP-02-E-BPA-39, at 20. BPA concurs that the public process for the DDC may be contentious, because it will entail issues of regional priorities and values and allocation of public benefits. DeWolf *et al*., WP-02-E-BPA-39, at 16. However, the "reverse CRAC's" lack of flexibility, potential for shifting risk to Treasury and taxpayers, and its inconsistency with the Principles all pose greater political risk. *Id.*

NRU's argument that BPA should implement a discretionary reverse CRAC in part due to a "problem of potential 'intergenerational' transfers,'" NRU Brief, WP-02-B-NI-02, at 9, is unfounded. Post-2006 costs are not driving the 2002 power rates. BPA is setting rates to recover costs for only the FY 2002-2006 period. BPA proposed the DDC mechanism to return monies that are not needed in this rate period, in effect helping to avoid any shifting of post-2006 costs into the FY 2002-2006 period. DeWolf *et al*., WP-02-E-BPA-39, at 20.

Evaluation of Positions

PPC and OURCA support a reverse CRAC rather than a DDC. A reverse CRAC would automatically return monies to the customers subject to the CRAC when reserves exceed a certain threshold level (*e.g.*, $850 million). PPC proposes that the distribution be automatic, but capped. On the other hand, NRU accepts BPA's revised DDC proposal and differs with BPA's DDC proposal only by contending that distributions should be given solely to customers. This would eliminate the need for the public process to decide how to distribute and allocate refunds. The DSIs argue that BPA does not have the authority to implement a DDC and that only Congress has the authority to allocate public benefits. DSI Ex. Brief, WP-02-R-DS-01, at 18.

NRU proposes the discretionary "reverse CRAC," which would be subject to the "same financial review and conditions as the proposed DDC." NRU claims BPA witnesses "agreed that a discretionary reverse CRAC on these terms would resolve the issue of the financial 'inflexibility' of a reverse CRAC. . . In addition, the panel acknowledged that it would be possible for BPA to model the DDC as a reverse CRAC." NRU Brief, WP-02-B-NI-02, at 10. NRU claims that it would be inequitable and unfair to distribute excess rate revenues to "stakeholders who did not contribute to the creation of the excess." NRU Ex. Brief, WP-02-R-NI-01, at 5. This proposal does offer a solution to BPA's need for financial flexibility and risk mitigation, since it accepts most of BPA's revised DDC proposal. However, it diverges from BPA's proposal by necessarily defining "stakeholders" as customers only. Given the nature of this issue--allocation of public benefits--BPA prefers to discuss and decide on allocating and dividing dividends in a less formal setting outside a rates 7(i) process. This approach does not preclude options such as NRU proposes, wherein customers subject to CRAC receive all the dividends. The money that customers have paid to BPA becomes money for use in meeting BPA's statutory and regulatory responsibilities and policy objectives. DeWolf *et al*., WP-02-E-BPA-39, at 18.

The design of the reverse CRAC does not provide BPA with the financial flexibility it needs to operate in times of uncertainty, nor does it represent sound financial practice. The automatic nature of the reverse CRAC does not allow BPA to forecast whether or not the excess reserves may be needed in the remaining years of the rate period. DeWolf *et al*., WP-02-E-BPA-39, at 15.

The IOUs contend that BPA's proposed DDC and capped CRAC will increase the likelihood for a cost shift to transmission customers by giving away money that may be needed in the rate period after the trigger and by not collecting enough money through the CRAC to cover expenses and costs. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 58. This argument would be more valid if BPA had proposed an automatic DDC distribution similar to the reverse CRAC proposed by other parties. BPA's DDC is designed to prevent returning money that may be needed in the years following the trigger. BPA's unprecedentedly robust risk mitigation package has been designed to meet the 88 percent TPP goal without the inclusion of a transmission surcharge. DeWolf *et al*., WP-02-E-BPA-39, at 6.

The DSIs contend that no utility regulated by FERC or state public utility commissions would be permitted "systematically to overcharge" its customers to reduce its risks "practically to zero," and then decide at its sole discretion whether to keep or how to dispose of the excessive funds collected. DSI Ex. Brief, WP-02-R-DS-01, at 19. But no "overcharging" is occurring in this rate proposal. Rates are set to recover a revenue requirement that reflects implementation of Cost Review savings; system augmentation purchases; repayment study results; and PNRR, reflecting a TPP goal that still places significant risk on Treasury. The DDC does not allow the wide-open “discretion “ implied by the DSIs. *See* Issue 2 *supra*.

Reserves in excess of the DDC threshold will be distributed unless needed to meet the 88 percent TPP goal over the ensuing five-year period. Lovell *et al*., WP-02-E-BPA-40, at 9. “Part of the rationale for this DDC design is to deal with the very concern the IOUs articulate--namely, that reducing reserves early in the rate period might, in some instances, later result in deferrals that would not have occurred otherwise. The additional requirements of the five-year forecast of reserves and TPP at the time of implementation provides a means for offsetting the likelihood of additional deferrals resulting from distributing dividends early in the rate period.” DeWolf *et al*., WP-02-E-BPA-39, at 20.

Decision

BPA will not replace the DDC with a “reverse CRAC.” BPA must maintain the financial flexibility to achieve the 88 percent TPP goal and to react to unknown risks, uncertainties, and costs in the near future. BPA’s DDC mechanism, unlike the automatic reverse CRAC, allows BPA to return reserves in excess of the threshold only after it is determined that those reserves are not needed to fulfill an 88 percent TPP on a rolling five-year forecast basis. BPA will not decide in this rate case how dividends will be allocated or distributed. Rather, a one-time only public process will be conducted before October 2001 to discuss and decide this issue.

Issue 3

Whether it is necessary at this time to determine the criteria for dividing and allocating any DDC amount.

Parties’ Positions

OURCA maintains that “the DDC, as designed and adopted in the DROD, violates the mandatory rate-setting principles of Section 7(i) of the Northwest Power Act.” OURCA Ex. Brief, WP-02-R-OU-01, at 4. NRU argues that BPA’s proposed DDC public process should be done through a section 7(i) process. NRU Ex. Brief, WP-02-R-NI-01, at 6. “The proposed DDC process of informally re-distributing hundreds of millions of dollars of BPA rate revenues that are determined to be excess to BPA’s cost-recovery requirements is, in fact, a rate making process. . . The proposed process to decide how to rebate the excess funds is merely a retroactive adjustment to rates.” *Id.* The DSIs argue that the Administrator lacks authority to overcharge customers and then selectively distribute dividends to entities other than those who were overcharged. DSI Ex. Brief, WP-02-R-DS-01, at 19.

BPA’s Position

It is not necessary to determine the criteria for dividing and allocating any DDC amount at this time. DeWolf *et al*., WP-02-E-BPA-13, at 29. The “rate mechanism” for how the DDC will be distributed, if and when there is a distribution to customers, is included in this rate case.

Evaluation of Positions

BPA has set its rates in this proceeding with the intent and purpose of recovering its costs and otherwise complying with statutory directives. BPA is not setting its rates with the purpose of accumulating excess revenues and triggering the DDC, any more than it is setting rates with a purpose of underrecovering its costs and triggering the CRAC. BPA is setting its rates for a future five-year rate period, one which happens to coincide with a great many uncertainties related to BPA's costs and revenues. Due to these factors, there is a possibility that the forecasting mechanisms that must be used to set BPA's rates will not project future costs and revenues as accurately as they would otherwise. The DDC is intended to deal with only the *possibility* that BPA will collect significantly more revenues than it currently envisions. DeWolf *et al*., WP-02-E-BPA-13, at 27-28. Such an eventuality is by no means certain. Thus, it is not necessary to deal with the issue of how excess revenues would be allocated under the DDC at this time.

Decision

It is not necessary at this time to determine the criteria for dividing and allocating any DDC amount. The issue of how excess revenues would be allocated under the DDC can be dealt with in a different proceeding, as proposed by BPA, prior to October 1, 2001.

7.6 Ending Reserve Level

Issue 1

Whether the TPP goal and the risk mitigation tools would lead to an "excessive" buildup of reserves.

Parties' Positions

The IOUs and PPC have argued that the expected value of ending reserves in BPA's proposal is too high.

The IOUs argue that "BPA expects to have approximately $750 million in reserves at the start of the 2002-2006 period . . . And BPA plans to add $127 million a year as "Planned Net Reserve [sic] for Risk" for five years to the already excessive level of reserves, which will produce a staggering $1.2 billion of reserves by 2006." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 50. "There is no question that BPA's reserve levels are massively higher compared to past cases and must be reduced. A reduction of the reserves would free up at least $700 million . . ." *Id.* at 51. The IOUs also state, "Furthermore, since the DDC is not included in BPA's model, any distributions that occur are not modeled, resulting in the model overstating the funds available to pay Treasury . . ." *Id.* at 59.

PPC seeks to reduce an "excessively large" $1.26 billion average ending reserve level to the "more reasonable level" of $850 million, which will provide reserves necessary to recover costs, repay Treasury, and maintain BPA's financial health. PPC Brief, WP-02-B-PP-01, at 6. This proposal may also limit attempts to privatize BPA. *Id.* In its brief on exceptions, PPC states that it still believes that $950 million is unreasonable in view of the fact that BPA can maintain an 88 percent TPP with $850 million in average ending reserve levels if BPA adopts the recommendations as set forth in PPCs direct testimony. PPC Ex. Brief, WP-02-R-PP-01, at 4.

The DSIs take exception to an "excessive build-up" of reserves, DSI Ex. Brief, WP-02-R-DS-01, at 18; stating BPA's risk mitigation package is unnecessarily costly to customers. *Id.* at 2-47 to 2-49. BPA proposes an unnecessarily high TPP, and could potential build a "war chest" for dam removal. *Id.*

In light of BPA's admission that it is proposing unprecedented reserves to position the agency to cover post-2006 fish costs, the IOUs ask the Administrator to reconsider reserve levels based on proper considerations only and lower the reserves accordingly. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 40.

However, several parties argue that BPA's level of reserves is not excessive. "OPUC generally agrees with BPA's approach to high ending reserves." OPUC Brief, WP-02-B-OP-01, at 5. UCUT argues that "BPA's reserve level must be protected to assure BPA the ability to meet the variety of potential unknown costs under its statutory requirement." UCUT Brief, WP-02-B-UC-01, at 25. CRITFC/Yakama and NEC/SOS (and Shoshone-Bannock by reference) argue that BPA's expected value of reserves is not only not excessive, but it is not high enough. *See* ROD section 7.6, *infra*.

BPA's Position

The expected value of ending FY 2006 reserves is the result of modeling BPA's risks, and the proposed set of risk mitigation tools that are designed to achieve the 88 percent TPP goal. It is the five-year, 88 percent policy standard that is the goal, not a particular expected value of reserves. DeWolf *et al.*, WP-E-BPA-39, at 10.

Given the unprecedented level of uncertainty BPA is facing over the FY 2002-2006 rate period, it is essential that reserves be adequate to meet the 88 percent TPP level. DeWolf *et al.*, WP-02-E-BPA-39, at 2. Together with CRAC, levels of PNRR must be set high enough to allow reserves to accumulate to the point where they fully cover the risks in all but 12 percent of the cases. *Id.* To prevent the accumulation of reserves in excess of BPA's long-term needs, but allow BPA to evaluate changes in its risk profile, the initial proposal contains a DDC. *Id.* at 13. The DDC would allow BPA to reassess its financial situation and the status of key regulatory policies before releasing funds that it might need. *Id.* at 12.

The modeling BPA presented in the initial proposal, wherein the expected value of reserves ramped up to $1.26 billion by FY 2006, did not take into account the fact that distributions would be made under the DDC. An approximation of the effects of the DDC was made and described in rebuttal testimony. *Id.* at 13-14. The expected value of ending FY 2006 reserves using this approximation was a little under $900 million. *Id.*

Evaluation of Positions

The expected value of ending FY 2006 reserves is the result of modeling. It is not a target or goal. DeWolf, *et al*, WP-02-E-BPA-39, at 10. Since the expected value of ending reserves reported in BPA's initial proposal did not include any numerical impact of the DDC, and the DDC is likely to reduce the expected value of ending reserves by $200-300 million, BPA believes there will be no excessive build-up of reserves. *Id.* at 10-15.

The IOUs and PPC both argue that BPA should lower the expected value of ending reserves. They propose using different parameters for the risk mitigation tools, such as CRAC and PNRR, or even eliminating some of the tools. The IOUs state that their proposal, which includes removing PNRR and uncapping the CRAC, would reduce the expected value of ending reserves to about $500 million. "A reduction of the reserves would free up at least $700 million to fund the Residential Exchange, without raising comparable preference rates." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 51.

However, NRU states that the IOUs' proposals (robust CRAC, no PNRR) should be rejected in favor of more prudent planning measures, such as PNRR, that allow BPA to build reserves as needed to a level below $1.2 billion, but certainly above $500 million. NRU Brief, WP-02-B-NI-02, at 29.

PPC agrees with NRU that the IOUs' $500 million reserve proposal is too low, and suggests that $850 million is a reasonable level. "The target level advocated by IOUs heads in the right direction, but at $500 million is even lower than updated reserve balances for 1999-2000 that will be used in formulating the draft 2002 forecast." PPC Brief, WP-02-B-PP-01, at 6. PPC also states "the [IOUs'] proposed elimination of PNRR is a shortsighted overreaction to BPA's financial package and should be rejected." *Id.* at 13. However, the PPC also argued that a $1.26 billion level of reserves is not necessary to keep BPA financially viable or ensure a high probability of Treasury payment. Hansen *et al.*, WP-02-E-PP-03, at 8.

The IOUs' risk mitigation package would result in significantly less rate stability due to significantly greater likelihood of CRAC triggering more frequently and by a larger amount. This is counter to BPA's need to keep rates relatively stable during this rate period, and is therefore unacceptable. This issue is further addressed in Issue 3 below.

The PPC proposal to achieve an $850 million reserve is based, in part, on having a reverse CRAC rather than a DDC. "PPC recognizes that higher reserves at the start of the 2002 rate period, along with cost reductions through implementation of BPA's Issues '98 plans, adjustments to the CRAC and replacement of the proposed dividend distribution with PPC's proposed reverse CRAC, would bring the average ending reserves level for the next rate period down to the more reasonable $850 million." PPC Brief, WP-02-B-PP-01, at 7. For reasons discussed elsewhere in this document, BPA's rate proposal includes the most current forecast of starting reserves (*see* ROD section 7.4, Issue 3), does not include adjustments to the CRAC (*see* ROD section 7.3), and does not include a reverse CRAC (*see* ROD section 7.5, Issue 2, *supra*). *See also* ROD section 7.7 *infra.*

BPA's current modeling methodology shows that an 88 percent TPP is not achievable with the PPC's $850 million expected value of ending reserves, and BPA is committed to achieving the 88 percent. However, the arguments of the PPC and IOUs focus on the $1.26 billion expected value of ending reserves, and do not fully consider BPA's rebuttal testimony wherein the impact of DDC distributions on ending reserves is discussed. In the initial proposal, the DDC included a threshold of $500 million in actual accumulated net revenues (equivalent to $1.2 billion in reserves) attributable to the generation function. In rebuttal testimony, BPA proposed to reduce the DDC threshold level by $250 million to the actual accumulated net revenues equivalent of $950 million reserves. At such time as the threshold is reached, reserves in excess of the threshold will be distributed unless it is demonstrated that some or all of the excess must be retained to meet the 88 percent TPP goal for the ensuing five-year period. DeWolf *et al.*, WP-02-E-BPA-39, at 12.

The DDC would have the effect of lowering both the average and maximum ending reserves. The $1.26 billion represents the upper bound on what the expected value would be if the DDC were factored in. *Id.* at 17. BPA would retain higher levels of reserves in those instances where the TPP analysis indicates they would be needed, such as a quantified risk that BPA might face large fish and wildlife expenses. If "excess" reserves were actually needed for large anticipated fish and wildlife costs, such a circumstance would significantly reduce BPA's attractiveness as a takeover target. *Id.* Moreover, if BPA retains reserves, it will be because they are needed for prudent operation of the business, especially for ensuring a high likelihood of making Treasury payments on time. *Id.* at 18. High reserve levels cannot mask annual performance problems, and BPA has a strong motivation to operate prudently no matter how high its reserves may be. *Id.* It is sound business practice for BPA to design its risk management measures and a dividend policy that adapts to changing circumstances. DeWolf *et al.*, WP-02-E-BPA-39, at 16.

BPA indicates that it is unable to model fully and adequately the triggering of the DDC, because there are two key pieces of information that will be available when it actually triggers that are not available now: (1) which fish alternative has been selected, and (2) a revised outlook of revenues, expenses and risk for the five-year period after the trigger year. DeWolf *et al.*, WP-02-E-BPA-39, at 11. These would be part of the forward-looking Treasury payment probability calculation conducted at the time the threshold is reached. In rebuttal testimony, BPA described an approximation of the DDC distributions. DeWolf *et al.*, WP-02-E-BPA-39, at 13-14. A reasonable conclusion to draw from this approximation is that the expected value of ending FY 2006 reserves will be well below $1.0 billion. *Id.* at 15. This DDC "simulation" does not capture the second key factor, though it attempts a simple approximation. An automatic reverse CRAC, as proposed by PPC and NRU, does not capture either of these key factors. Therefore, any simulation misses a key factor that the process is designed to account for.

So, though BPA's proposal does not include modeling the distributions of any dividends, the modeling does show the DDC threshold being reached an estimated 57 percent of the time. When the threshold is reached, dividends will be distributed unless BPA determines the reserves above $950 million are needed to maintain an 88 percent TPP for the subsequent five-year period. This will result in expected ending reserves somewhat lower than $1.2 billion. The approximation described in BPA's rebuttal testimony resulted in a little under $900 million. *Id.* at 14.

In their direct and rebuttal testimony, NRU raised issues having to do with BPA's potentially high level of ending reserves. However, these issues were not raised in brief, and thus are waived. In their direct testimony, NRU stated that "they do not support the accumulation of maximum or average reserves at the high levels proposed by BPA. BPA's 1993 ROD (page 71) references operating in a 'sound and business like manner.' In my judgment, BPA's reserve proposal does not meet that test." Saven, WP-02-E-NI-01, at 8. More specifically, NRU argued that such high levels of ending reserves increase the attractiveness of selling BPA and using the proceeds for other purposes, provides ammunition for members of Congress to move BPA from cost-based to market-based rates, and puts pressure on the agency to spend money. *Id*. at 8-9. In their brief on exceptions, the DSIs argue that BPA, in its Draft ROD, did not justify why it needs such "excessive" reserves, especially taking into consideration Slice contracts. DSI Ex. Brief, WP-02-R-DS-01, at 39. This is addressed in ROD section 16.6.

Decision

BPA's TPP goal and risk mitigation tools will not lead to a build up of "excessive" reserves. BPA sets its PNRR values to a level adequate to meet its 88 percent TPP goal, given the parameters of other risk mitigation tools including CRAC. In the event there is an accumulation of reserves in excess of BPA's long-term needs, the DDC provides for the "excess" to be rebated or otherwise distributed. A distribution would reduce the level of reserves to either $950 million or a higher amount that is necessary to meet the 88 percent TPP. The purpose of the DDC is, in fact, to avoid the accumulation of "excessive" reserves.

Issue 2

Whether BPA should have a higher expected value of ending reserves.

Parties' Position

CRITFC/Yakama, NEC/SOS, UCUT, and OPUC all recommend high levels of ending reserves. UCUT "supports a strong level of reserves." UCUT Brief, WP-02-B-UC-01, at 25. UCUT stated that "BPA's reserve level must be protected to assure BPA the ability to meet the variety of potential unknown costs under its statutory requirement." *Id.* NEC/SOS state that "BPA needs to raise rates high enough to pay for most of the fish scenarios in the next rate period without going over market. This should be done by setting a "target" ending reserve of $1 billion - $1.75 billion for 2006." Weiss, WP-02-E-NA-01, at 7-14. CRITFC/Yakama state that an ending reserve of $1.6 billion would allow Bonneville to cover the future costs of decisions made in the current rate period, remain competitive, and assure Treasury repayment for the FCRPS. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 45, 47. CRITFC/Yakama base this conclusion on results from a different model, "Strandsim." Sheets, WP-02-E-CR/YA-01, at 3.

CRITFC/Yakama state that NRU provides no new analysis that suggests that a reserve would not reduce potential rate increases in 2006 and improve repayment to the Treasury. This fails the test of reasonableness. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 19.

Shoshone-Bannock support and join by reference the positions and suggested remedies of CRITFC/Yakama related to deficiencies in BPA's proposal with meeting TPP and adequately addressing the risks after 2006. Shoshone-Bannock Brief, WP-02-B-SB-01, at 9.

NRU, on the other hand, argued that a high level of ending reserves would become an "attractive nuisance." Saven, WP-02-E-NI-0 1, at 8. NRU opposes the CRITFC/Yakama and NEC proposals to set an "Ending Reserves" target of $1.6 billion and/or increase proposed rates. NRU argues that the CRITFC/Yakama and NEC proposals are contrary to BPA's statutory mandate to recover only its costs. NRU Brief, WP-02-B-NI-02, at 12. NRU also states that the CRITFC/Yakama testimony presents an incomplete description of the NWPPC report on BPA costs and revenues. NRU Brief, WP-02-B-NI-02, at 13. CRITFC used a NWPPC report entitled "Analysis of the BPA's Potential Future Costs and Revenues" and the Council's "Strandsim" model to justify CRITFC's argument that BPA should establish a $1.6 billion ending reserve target. "His (CRITFC's) conclusions go well beyond any that may be fairly drawn from that study. His recommendations should be rejected." *Id.* at 13-14. However, CRITFC/Yakama argue that their testimony clearly states that the analysis was done using a model developed by the NWPPC and reasonable assumptions developed by CRITFC/Yakama. The testimony does not claim that the analysis was the Council's. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 19.

OPUC "generally agrees with BPA's approach to high ending reserves." OPUC Brief, WP-02-B-OP-01, at 9. However, OPUC argues that BPA should adopt an end of period reserves target that provides for $500 million in reserves 90 percent of the time. *Id.* at 5.

BPA's Position

BPA has not proposed a reserves target or a reserve plan in this rate proceeding. Rather, BPA has modeled its risks and proposed a set of risk mitigation tools that are designed to achieve the 88 percent TPP goal. It is the five-year, 88 percent policy standard that is the goal, not a particular expected value of reserves. DeWolf *et al*., WP-02-E-BPA-39, at 10. It is also impossible for BPA to guarantee any minimum level of starting FY 2007 reserves. *Id.* at 39.

As stated earlier, the range of fish and wildlife costs included in this rate proceeding is robust, and represents a reasonable range of costs given the variety of possible future alternatives. *Id.* at 32.

BPA's proposal implies a 70 to 80 percent chance of having at least $500 million in reserves at the end of 2006. Increasing this probability to a 90 percent probability of having at least $500 million at the end of FY 2006 would require: (1) abandoning the 88 percent TPP standard; and (2) either: (a) making the CRAC significantly more powerful, which would increase the frequency of CRAC triggering and the magnitude of the CRAC revenue increases; or (b) raising rates significantly. Either of these would reduced rate stability. Rate stability is a key BPA goal in this rate case. DeWolf *et al.*, WP-02-E-BPA-39, at 38.

BPA has not performed Strandsim analyses, which is the basis for CRITFC/Yakama's recommendation. As CRITFC/Yakama's testimony admits, Strandsim is not one of the models used by BPA in its rate case, and its estimates are different and in some cases not as detailed as the assumptions used in BPA's revenue requirement. Sheets, WP-02-E-CR/YA-01, at 4. There are many differences in data, scope, and analytical assumptions. This makes the results very difficult to compare meaningfully, especially in light of the enormous uncertainty, both between now and FY 2006 and during the post-FY 2006 period. DeWolf *et al.*, WP-02-E-BPA-39, at 39.

Evaluation of Positions

CRITFC/Yakama and NEC/SOS argue that BPA should have an FY 2006 ending reserve level of $1.6 billion, to assure the ability to meet potential unknown costs and assure Treasury payments. However, the expected value of ending reserves is a result of BPA's modeling, not a target. *Id.* at 10. BPA's modeling demonstrates that adding PNRR to the revenue requirement sufficient to achieve 88 percent TPP results in an expected value of ending reserves of $1.2 billion (without including the impact of the DDC). BPA would have to add unnecessarily to PNRR to achieve the level recommended by CRITFC/Yakama and NEC/SOS, which would result in a higher TPP than the 88 percent goal, and would result in higher rates, which would violate Principle No. 5 of the Principles.

CRITFC/Yakama's proposal that BPA raise the expected value of ending reserves to the level of $1.6 billion is based on analysis using the "Strandsim" model. This is the model used in the NWPPC report entitled *Analysis of the Bonneville Power Administrations' Potential Future Costs and Revenues*. CRITFC/Yakama used it to "estimate the size of a reserve that might be needed to cover the Snake River and John Day Dams to Natural River plus the Clean Water Act costs alternative." Sheets, WP-02-E-CR/YA-01, at 4. As CRITFC/Yakama's testimony admits, Strandsim is not one of the models used by BPA in its rate case. *Id.* There are many differences in data, scope, and analytical assumptions. This makes the results very difficult to compare meaningfully, especially in light of the enormous uncertainty, both between now and FY 2006 and during the post-FY 2006 period. DeWolf *et al.*, WP-02-E-BPA-39, at 39. CRITFC/Yakama's argument fails to acknowledge the other risk mitigation tools the report references (which BPA has, in effect, adopted), or the higher reserves BPA has now compared to those in the Study. NRU Brief, WP-02-B-NI-02, at 13. It is inappropriate to try to impact 2002-2006 rates by making arguments about post-2006 costs and revenues, particularly using models and methodologies unknown to and untested by the rate case participants.

NRU argues that BPA's strategy provides enough, if not too much, protection. NRU also argues that CRITFC/Yakama advocate establishing ending reserves to fund one particular set of fish and wildlife alternatives, the most expensive. This violates the Principles. The only potential justification for recovering such amounts ($1.6 billion) of excess revenue is to finance high-cost fish and wildlife programs these groups may favor. NRU Brief, WP-02-B-NI-02, at 12-13.

BPA's risk mitigation tools are sufficient to achieve an 88 percent TPP and will result, without modeling DDC distributions, in an expected value of ending reserves of about $1.2 billion. To target a higher level of ending reserves would result in higher rates, and rates contrary to BPA's statutory mandate to recover only its costs.

Decision

BPA will continue to model its risks and risk mitigation tools and set a level of PNRR sufficient to achieve an 88 percent TPP.

Issue 3

Whether the flat annual pattern of PNRR in revenue requirements, and the exclusion of DDC from ToolKit modeling, cause TPP to be lower than the 88 percent goal.

Parties' Positions

The IOUs contend that BPA's proposal actually achieves less than the stated 88 percent TPP. "This is because of the combination of a level PNRR recovery over the rate period and BPA's failure to model the DDC in the Toolkit runs that arrive at the TPP percentage." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 57. BPA plans to collect $127 million of PNRR for each the five years of the rate period. The IOUs claim that by levelizing the PNRR over the five-year period, TPP is higher in the early years and lower in the later years, meaning that PNRR is shifted away from the years that cause more risk to years that cause less risk. Further, "[b]y proposing a DDC in connection with this unbalanced PNRR collection, BPA amasses large net revenues before they are needed and is more likely to distribute them if the DDC triggers, such that the reserves are no longer available when needed. As a result, BPA substantially overstates the 88 percent TPP for the five-year period. Furthermore, since the DDC is not included in BPA's model, any distributions that occur are not modeled, resulting in the model overstating the funds available to pay Treasury and hence overstating the TPP." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 57-58.

BPA's Position

The expected value of reserves itself is uncertain because BPA was unable to use its models to reflect the operation of the DDC. Two uncertainties were not modeled: (1) distributions under the DDC can reduce or "zero out" the accumulation of reserves above the DDC threshold; and (2) decisions on the exact amounts to be distributed will be made during the rate period, at such time as the threshold is reached. At such time as the threshold is reached, reserves in excess of the threshold are distributed unless it is demonstrated that some or all of the excess must be retained to meet the 88 percent TPP goal for the ensuing five-year period. It is this five-year, forward-looking 88 percent TPP test that BPA was unable to model in its initial proposal. This demonstration entails a financial forecast and TPP analysis that takes into account risk factors prevailing at that time. The forecast and TPP analysis would undergo the scrutiny of a public review and comment process before decisions are made to reduce amounts that otherwise would be distributed. DeWolf *et al*., WP-02-E-BPA-39, at 11.

Since the methodology for performing a five-year TPP test in FY 2002, FY 2003, and so on has not been developed yet, and the data that will be used then does not exist now, BPA must approximate how that test would work. DeWolf *et al*., WP-02-E-BPA-39, at 15.

BPA's goal is to make all five annual payments on time and in full 88 percent of the time. Since BPA is not attempting to adjust rates and revenues year-by-year to meet an annual probability target, leveling PNRR across the five years of the rate period does not constitute overcollecting in some years and undercollecting in others. Lovell *et al*., WP-02-E-BPA-40, at 7-9. The Toolkit run in the initial proposal shows that collecting a constant $127 million of PNRR offsets the greater outyear risks by amassing higher reserves early on. *Id*.

BPA has designed the DDC to deal with the very concern raised by the IOUs--namely, that reducing reserves early in the rate period might, in some instances, later result in deferrals that would not have occurred otherwise. Distributions under the DDC do not occur automatically--when the threshold is reached, BPA must conduct a five-year forecast of reserves and assess TPP; cash over the threshold is distributed if it is not needed to meet the five-year TPP goal. This offsets the chance of additional deferrals resulting from distributing dividends early in the rate period. Lovell *et al*., WP-02-E-BPA-40, at 9.

<u>Evaluation of Positions</u>

As the IOUs contend, the DDC threshold could be reached more quickly with level annual PNRR amounts, rather than increasing levels. The probability of the DDC threshold being reached is lowest in the early years of the rate period. *See* Lovell *et al*., WP-02-E-BPA-40, Attachment A, "No. of DivDists." However, PNRR actually mitigates risk more effectively for the whole rate period the earlier it is available, since the added reserves can be available to mitigate risk over multiple years. That is, raising reserve levels in early years raises TPP more than the same increase to reserve levels in later years. Therefore, assigning level annual amounts of PNRR, when there is less that is apparently needed in the early years, does not have the effect of lowering TPP. Indeed, it likely raises it.

The IOUs state that TPP is 2 percent higher in the early years than in the later years, and that annual PNRR is misaligned with annual risks, which causes TPP to be lower than the 88 percent that BPA states. While it is true that annual probabilities are higher in the early years, the point is moot because BPA set the probability goal as a five-year goal, not an annual goal. BPA's goal is to make all five annual payments on time and in full 88 percent of the time. *Id*. at 7.

BPA cannot accurately model the DDC since, by design, it involves a forward-looking financial forecast and TPP assessment based on conditions at the time the threshold is reached. Once the threshold is reached, BPA will be required to forecast and analyze its net revenues, reserves and risks over the five-year period beginning with the year after the threshold is reached. BPA will then determine whether any or all of the excess will be needed to meet the TPP goal for that five-year period. BPA did attempt a simulation in order to get some sense of the impact of the DDC triggering on the expected value of ending reserves. It is true that distributing dividends will decrease reserve levels, but it is unclear whether TPP would be reduced, because distributions will be made only to the extent that cash is not needed to meet the TPP goal. If a distribution can be made, BPA will distribute only the amount in excess of that needed to maintain the five-year 88 percent TPP.

Decision

BPA will continue to include PNRR in equal annual amounts. DDC modeling will not be included in the TPP calculation because it cannot be modeled accurately and because its impact on TPP, if any, is unclear conceptually.

7.7 Reasonableness of BPA's Risk Mitigation Strategy Taken as a Whole

Issue

Whether BPA's risk mitigation package, taken as a whole, is internally consistent, logical, and reasonable.

Parties' Positions

Two parties in the rate case argued in their briefs on exceptions that BPA's rate proposal was flawed by internal inconsistencies resulting from a piecemeal approach to addressing risk mitigation issues.

NEC/SOS argued that:

> It is impossible to exercise statutory judgment is [sic] the decision in [sic] impermissible [sic] piece-mealed. The closest analogy arises when a federal agency deliberately breaks environmental action into numerous meaningless discrete and "harmless" segments in order to avoid the duty of exercising judgment over the total range of consequences . . .
>
> [T]he rule of agency decision-making which requires reasoned decision-making in EIS cases is applicable and enforceable to analyze BPA methodology. The kind of inflexibility which retroactively rattifies [sic] a foregone ratemaking decision permeates the DROD.

NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 2-3.

Similarly, OPUC claimed:

> . . . [I]n the Draft Record of Decision (Draft ROD) BPA's approach to deciding issues is to deconstruct the arguments, deal only with the pieces, and to ignore the larger problems posed by the issues . . . Thus BPA has not adequately responded to the overarching issue raised by OPUC: the risk mitigation strategy, particularly the design of the CRAC, forecloses BPA's ability to cover high costs this rate period and leaves BPA unnecessarily vulnerable to extreme rate spikes in the next rate period and violates the requirement that BPA's rates be set "in accordance with sound business principles." 16 U.S.C. §839e(a)(1).

OPUC Ex. Brief, WP-02-R-OP-01, at 2-3.

BPA's Position

In its rate proposal, BPA has presented an integrated package that displays the following characteristics:

- Using principles outlined in the Subscription Strategy, it keeps BPA competitive by providing customers with stable rates from the current rate period into the next rate period and by limiting potential rate increases during the rate period.
- It provides BPA with a strong financial position by strictly adhering to an 88 percent probability standard for repaying Treasury on time and in full over the FY 2002-2006 rate period. *See*, *supra*, section 7.2, Issue 2.
- Through CRAC and the DDC, it contains mechanisms for addressing potential problems arising from under- and over-collecting revenues. *See, supra*, section 7.1.
- By analyzing a spectrum of 13 distinct Fish and Wildlife Alternatives in setting rates that meet an 88 percent TPP standard, it positions BPA to attain a similarly high (80-88 percent) TPP in the FY 2007-2001 rate period. *See, supra*, section 5.4.7.2, Issue 6.

Evaluation of Positions

NEC/SOS's and OPUC's criticisms express a valid concern about an inherent characteristic of the ROD. Because it must address each and every major issue posed by parties during the rate case, the ROD necessarily breaks the discussion of BPA's overall rate proposal down into component parts that are amenable to focused discussion. It is useful, however, to end this chapter on risk mitigation with an overview of how the components of BPA's proposal fit together.

As articulated by OPUC, the pivotal issue that both OPUC and NEC/SOS are raising is whether or not BPA's risk mitigation strategy "leaves BPA unnecessarily vulnerable to extreme rate spikes in the next rate period." OPUC Ex. Brief, WP-02-R-OP-01, at 3. This argument is built upon two assertions: first, that BPA does not adequately account for the risk inherent in the multiple deferrals that occur in a percentage of the games in the ToolKit analysis (*supra*, section 7.2, Issue 3), and second, that the analysis NEC's witness prepared for direct testimony demonstrated that BPA is not adequately positioned for the post-2006 period, thereby violating Fish and Wildlife Funding Principle No. 4 (*supra*, 5.4.7.2, Issue 5). The parties are additionally claiming that by treating these two basic considerations separately, or in "piecemeal" fashion, the ROD obscures the fact that BPA's decision is "illogical and impermissible." NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 2.

BPA asserts that neither of the points is valid.

As discussed *supra* in section 7.2, Issue 3, BPA assumes a different level of risk tolerance than either NEC/SOS or OPUC in evaluating the rate proposal. This is not a matter of one approach or the other being unreasonable, only different. NEC/SOS and OPUC' s proposals would have

BPA err on the side of possible over-collection of revenues in order to avoid the possible occurrence of certain low probability outcomes that would have a high impact if they occurred. In support of this point, however, they have chosen to focus selectively on certain ToolKit results to the exclusion of others, and thereby present a partial picture of BPA's risk profile. BPA's modeling methodology, built on Monte Carlo simulation, is designed to produce a wide range of outcomes, the worst of which are extremely severe and the best of which are extremely rewarding. The mere fact that seven percent of the games simulated in ToolKit have multiple deferrals and that the worst of these games would put BPA in severe debt is not, in itself, an indication that BPA is putting itself in jeopardy. What also needs to be noted is the expected impact of these worst cases, relative to the entire set of games played in ToolKit. The estimated effect, when the deferral amounts are weighted by their probability of occurrence, is relatively minor: average ending reserves fall by $56.4 million in FY 2006. BPA asserts that this level of risk, the product of its TPP methodology, is acceptable and reasonable.

The significance of multiple deferrals, however, was only one piece of the argument advanced by OPUC and NEC/SOS regarding BPA's ability to cover high costs. The other piece was an analysis prepared by NEC's witness for direct testimony that allegedly demonstrated the need for additional revenues equivalent to an additional three- to five-mill rate increase. As noted *supra* in section 5.4.7.2, BPA disagrees with a number of the assumptions underlying the analysis. BPA asserts that not only is it not required to analyze rates for FY 2007-2011, but that doing so would be ill-advised.

There were two major points underlying BPA's assertion that it was not possible to do the analysis needed to determine risks or rates for the FY 2007-2011 period. First, BPA lacks information necessary to make the modeling and analytical assumptions necessary to adequately characterize the risks and uncertainties of that period. Second, the data needed to run analyses with the type of rigor needed is not available.

This broader consideration is what underlies BPA's statement that the technical problems associated with modeling and quantitative analysis of BPA's power business post-2006 are greater than implied by the parties. *See, supra*, section 5.4.7.2, Issue 3. Each time BPA goes through the process of resetting rates, it has the opportunity to reexamine the environment within which it operates and determine which risks and uncertainties need to be considered and how heavily to weight them. The set of relevant risks may vary considerably from one rate case to another, and the guidelines for mitigating them at one point in time may not be relevant five years later. In the 1996 rate case, BPA relaxed its 88 percent TPP standard because, at that time, its competitiveness in the market was an overriding issue, but the need to evaluate fish and wildlife obligations was not. Had BPA attempted a 10-year projection of risk and revenue requirements based upon the picture of the world it had at that time, its characterization of the FY 2002-2006 rate period would likely have suffered from "assumption drag" (continued use of out-of-date assumptions). This means that the issues of greatest importance for the FY 1996-2001 rate period would have colored the projections for the rate period to follow, which would likely have borne little resemblance to the analysis conducted in support of this proposal.

BPA provided a list of assumptions that would have to be made in order to perform any sort of analysis of FY 2007-2011 (*supra*, section 5.4.7.2, Issue 3). The intention was to illustrate the near impossibility of meaningfully framing the proper analytical questions and selecting an appropriate set of uncertainties to be modeled. Lacking this sort of guidance, the only alternative is to incorporate ever-larger numbers of uncertainties into the analysis in the hope of capturing the appropriate ones as a subset. Indeed, in their initial brief NEC/SOS responded to this list of uncertainties by asserting that this meant that the range developed by its witness when preparing a minimum reserves target in direct testimony should be widened even further. NEC/SOS Brief, WP-02-B-NA/SA-01, at 21-22.

This, however, is the fundamental problem with dealing with uncertainties that compound over time. As one extends the analysis of risk farther into the future, the resulting range of values that need to be mitigated eventually widens to the point where prescribing a meaningful set of measures designed to accomplish that mitigation becomes impossible. Adding more risk variables that may or may not be relevant (or continuing to model effects that may no longer be relevant) compounds the problem.

BPA must assess the full period for which it is setting rates in its rate proposal, and as noted *supra* in ROD section 7.2, Issue 3, this involves addressing a very wide range of risks. However, at the time of ratesetting, BPA has a reasonably clear idea of which risks are relevant (and through CRAC and the DDC has included mechanisms to offset potential under- or over-collection of revenues). This is not true of the FY 2007-2011 period, and for this reason BPA finds it ill advised to attempt extending analysis into that period.

A post-2006 revenue requirement developed now would not be rooted in planned costs or a reasonable range of expected costs because fish and wildlife recovery, power purchase and other resource, and capital costs are uncertain. Further, uncertainties regarding Congressional action and marketing strategy are great. BPA is a Federal agency charged with setting rates to recover its costs. NEC/SOS's analysis conducted to demonstrate the need for a minimum reserves standard was developed using a simple methodology that calculated how high BPA's rates would have to be raised after FY 2006 given different ending (FY 2006) reserves levels, using the variance in market forecast of rates and the variance in the ending reserves level produced by ToolKit in the analysis for the initial proposal. *See, supra,* section 5.4.7.2, Issue 5. While NEC/SOS never characterized this approach as anything but a simple calculation to be used in the absence of a more rigorous and detailed study, the analysis leaves the assumptions about changes in BPA's risk environment in the post-2006 period unaddressed. The general inability of NEC/SOS or BPA to meaningfully address those uncertainties is what led BPA to conclude that neither the studies provided by BPA nor the NEC/SOS analysis match the rigor that BPA demands of TPP studies. *See* ROD section 5.4.7.2, Issue 5.

Although it is certainly possible that conditions could occur that would result in BPA incurring heavy debt by the end of FY 2006 (and a rate spike in the subsequent rate period), the results of the ToolKit analysis used for this proposal indicate that the probability of these scenarios would be low. The analysis shows that BPA successfully makes all of its Treasury payments on time and in full over the FY 2002-2006 rate period 88 percent of the time and fully recovers from the effects of deferral in a portion of the 12 percent of the cases where one or more deferrals occurs. Given the difficulties described *supra*, the analysis prepared by NEC/SOS does not demonstrate that BPA is ill-prepared for the FY 2007-2011 rate period.

BPA's risk mitigation strategy meets criteria that ensure BPA will repay Treasury and meet its obligations to cover the costs of fish and wildlife mitigation while meeting the goals of its Subscription Strategy.   It does not expose itself to undue risk, and by balancing its statutory obligations with its ability to be a good business partner to its customers, provides a high likelihood that its proposal will be implemented effectively.

<u>Decision</u>

BPA's risk mitigation package, taken as a whole, is internally consistent, logical, and reasonable.

8.0 TRANSMISSION AND INTER-BUSINESS LINE ISSUES

8.1 <u>Introduction</u>

PBL has forecasted the inter-business line revenues and expenses that it will incur during the FY 2002-2006 rate period. These expenses include the Transmission Expense Forecast, GTA Expense Issues, Delivery Segment Costs, and Generation Inputs for Ancillary Services. These forecasts were used in developing the power revenue requirement. Forecasted transmission expenses do not constitute a transmission rate proposal and will not be binding on any transmission rate case or settlement. *See* 64 Fed. Reg. 44,318, 44,323 (1999) (stating that transmission rates will be developed in a separate transmission rate case).

PBL has forecasted the transmission expenses that it will incur in its marketing efforts. Cherry and Metcalf, WP-02-E-BPA-10, at 8. PBL incurs transmission expenses from four source categories: (1) PF sales; (2) "grandfathered" contracts; (3) market sales; and (4) other transmission expenses. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 91. *See also* Pedersen and McRae, WP-02-E-BPA-28, at 1. The DSIs, Alcoa, and Vanalco challenged various aspects of this forecast. *See* DSI Brief, WP-02-B-DS-01, at 54-56; DSI Ex. Brief, WP-02-R-DS-01, at 22; Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 64; Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 35.

BPA proposed to continue existing GTA service to current loads for delivery of Federal power through the FY 2002-2006 rate period. 64 Fed. Reg. 44,318, 44,328 (1999). For GTAs that expire during the rate period, BPA proposed to obtain comparable transfer service under the transmitting utility's open access transmission tariff. Pedersen and McRae, WP-02-E-BPA-28, at 8. BPA proposed that the costs of transfer service for delivery of Federal power will be spread over all BPA power sales; these costs are estimated to be around $52 million per year through the rate period. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 96; Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 49-54. Also, BPA proposed that GTA service for delivery of Federal power would not be available to new preference customers. Pedersen and McRae, WP-02-E-BPA-28, at 8. Additionally, BPA proposed that GTA service for delivery of Federal power would not be available for preference customers' annexed load. *Id*.

BPA proposed that PBL will continue to pay for delivery segment costs only when PBL is the transmission customer using those facilities. Cherry and Metcalf, WP-02-E-BPA-10, at 7.

PPLM proposed that BPA should establish in the power rate case a minimum percentage of generation inputs for ancillary services that the TBL would be required to purchase from the open market through a competitive bid process, or, in the alternative, establish a market price cap for PBL-supplied generation inputs. PPLM Brief, WP-02-B-PM-01, at 1-10.

BPA proposed an allocation method for the costs of generation inputs for the reactive supply and voltage control from generation sources ancillary service, based on reactive capability under normal operating conditions. *See* DeClerck *et al.*, WP-02-E-BPA-26. BPA proposed to set a fixed inter-business line charge for these generation inputs. Cherry and Metcalf, WP-02-E-BPA-10, at 5. This charge will be used in developing the portion of the transmission revenue requirement associated with the reactive power ancillary service in the transmission rate case. *Id.* TBL would be required to purchase these reactive power generation inputs from PBL at the fixed inter-business line charge. *Id.*

BPA proposed to allocate costs to the operating reserves generation input by using an embedded cost methodology based on the cost of the hydro projects used to meet operating reserve obligations on the system. DeClerck *et al.,* WP-02-E-BPA-26, at 9. BPA proposed to allocate costs to the regulating reserves generation input by using an embedded cost methodology based on the cost of the hydro projects used to meet the regulating reserve obligations of the system; these consist of the 10 hydro projects that are equipped with automatic generation control (AGC). *Id.* at 13. BPA proposed that both of these methodologies would exclude the costs of the non-performing assets (including WNP-1, -3, and Trojan decommissioning), and conservation. *Id.* at 10, 13.

For operating reserves and regulating reserves, BPA proposed cost-based caps for the per-unit inter-business line charge for capacity-based generation inputs to the regulation service and operating reserves ancillary services. Cherry and Metcalf, WP-02-E-BPA-10, at 4. PBL used these unit costs and an estimate of unit sales to TBL to forecast revenue from sales of these products. *Id.* at 4-5. TBL would not be required to purchase these generation inputs from the PBL, and PBL may discount the unit charge for these products. *Id.* at 4. PGE proposed that BPA adopt the High Load Factor Group's (HLFG) recommendation that the CRAC apply to the inter-business line charge for the operating reserves generation input. PGE Brief, WP-02-B-GE-01, at 12.

BPA proposed to assess TBL an annual inter-business line charge for Generation Dropping provided by PBL. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 84-87. *See also*, DeClerck *et al.*, WP-02-E-BPA-26, at 16-17. BPA proposed to assess TBL an annual inter-business line charge for Station Service provided by PBL. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 87-88. *See also* DeClerck *et al.*, WP-02-E-BPA-26, at 18-19.

8.2 Transmission Expense Forecast

Introduction

PBL has forecasted the transmission expenses that it will incur in its marketing efforts. Cherry and Metcalf, WP-02-E-BPA-10, at 8. This forecast was used in developing the power revenue requirement. *Id.* This forecast does not constitute a transmission rate proposal and will not be binding on any transmission rate case or settlement. *Id. See also,* 64 Fed. Reg. 44,318, 44,323 (1999) (stating that transmission rates will be developed in a separate transmission rate case). PBL incurs transmission expenses from four source categories: (1) PF sales; (2) "grandfathered" contracts; (3) market sales; and (4) other transmission expenses. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 91; Pedersen and McRae, WP-02-E-BPA-28, at 1.

Issue 1

Whether BPA should modify the transmission expense forecast presented in the initial proposal to reflect the PBL policy decision to abandon its plan to be the transmission contract holder for many full and partial requirements customers who choose network service from the TBL.

Parties' Positions

No party raised this as an issue in an initial brief or brief on exceptions.

BPA's Position

BPA proposed modifying for the 2002 final rates the transmission expense forecast presented in the initial proposal by removing the PF sales transmission expense line item and the PF sales transmission revenue line item from the Wholesale Power Rate Development Study Documentation. Pedersen and McRae, WP-02-E-BPA-28, at 2.

Evaluation of Positions

At the time the initial rate proposal was published, PBL planned to be the transmission contract holder for many full and partial requirements customers who choose network service from the TBL. Pedersen and McRae, WP-02-E-BPA-28, at 2. By the time BPA's direct testimony was filed, PBL abandoned that plan and instead will offer to be a designated agent for PF customers with loads of 20 average annual megawatts or below. *Id.* This will not affect the rate calculation, because transmission expenses forecasted by PBL for PF sales had equivalent associated revenue for PBL under the transmission contract holder arrangement, resulting in a net expense of zero. *Id.* As a designated agent, PBL will not be billed by TBL on behalf of the PF customer; nor will PBL bill the customer for transmission service. *Id.* Under the designated agent agreement, the customer will be billed directly by TBL. *Id.* Thus, the PF sales transmission expense line item and the PF sales transmission revenue line item will be removed from the Wholesale Power Rate Development Study Documentation for the 2002 final rates.

Decision

BPA has modified the transmission expense forecast presented in the initial proposal by removing the PF sales transmission expense line item and the PF sales transmission revenue line item from the Wholesale Power Rate Development Study Documentation for the 2002 final rates.

Issue 2

Whether BPA should modify the transmission expense forecast presented in the initial proposal to reflect an assumption that BPA would have to procure additional transmission services for only 57 percent of HLH sales and 47 percent of LLH sales, thus reducing the forecast for transmission expenses from short-term sales by $18 million annually.

Parties' Positions

The DSIs argue that "BPA should revise its transmission cost estimates to include greater 'sheltering,' based upon the 1996 [rate case] analysis . . ." such that transmission expenses from short-term sales are reduced by $18 million annually, based on an assumption that "BPA would have to procure additional transmission services for only 57 percent of HLH sales and 47 percent of LLH sales." DSI Brief, WP-02-B-DS-01, at 55-56. The DSIs state that PBL's assumption that PBL will have to procure additional transmission services for 85 percent of HLH and 75 percent of LLH sales is unreasonable. *Id.* Further, the DSIs state that "[a]bsent evidence that such 'sheltering' is unavailable, BPA cannot offer substantial evidence for departing from the much lower percentages used in 1996." DSI Ex. Brief, WP-02-R-DS-01, at 22. The DSIs argue that "The Draft ROD's refusal to reduce transmission expenses associated with short-term sales is arbitrary and capricious . . ." *Id.*

Alcoa and Vanalco argue that "BPA has overstated the cost of obtaining transmission capacity necessary for export sales to the Southwest by $32 million per year for the rate period." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 64 (citing direct testimony of the Joint DSIs, Shoenbeck and Bliven, WP-02-E-DS/AL/VN-03, and Shoenbeck and Bliven, WP-02-E-DS/AL/VN-06); *see also* Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 35.

BPA's Position

PBL's assumption that it will have to procure transmission for 85 percent of HLH and 75 percent of LLH sales levels is based on internal discussions with power traders and forecasters. Pedersen and McRae, WP-02-E-BPA-52, at 5. PBL compiled the best available data on FY 1999 sales made in the short-term and within-month markets. *Id.* The data indicated that presently nearly 100 percent of the HLH sales and 96 percent of LLH sales are made with a delivery clause. *Id.* Transmission customers are becoming more sophisticated in the procurement and utilization of transmission capacity and therefore, BPA expects to see some reduction in delivered sales. *Id.* Thus, PBL believes the forecasted need to procure transmission for 85 percent of HLH sales and 75 percent of LLH sales is a reasonable expectation for the post-2002 period. *Id.*

Evaluation of Positions

With respect to forecasted additional transmission service for short-term transactions, the DSIs criticize PBL for basing its assumptions on "nothing more than 'internal discussions with power traders and forecasters.'" DSI Brief, WP-02-B-DS-01, at 56. The DSIs propose an alternative forecast based on 1996 rate case data. *Id.* The PBL assumptions are based on the best available data; that data looks forward into the rate period for which rates are being set in this rate case. Pedersen and McRae, WP-02-E-BPA-52, at 5. PBL based its forecasted need to procure transmission for 85 percent of HLH sales and 75 percent of LLH sales for the post-2002 period on the data indicating that presently nearly 100 percent of the HLH sales and 96 percent of LLH sales are made with a delivery clause. Pedersen and McRae, WP-02-E-BPA-52, at 5. PBL reduced the delivery data by forecasted available sheltering to reach the forecasted procurement needs. *See* Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 93. In light of this data, a conclusion that only 57 percent and 47 percent respectively of such sales would require procurement of additional transmission service for delivery is unreasonable. PBL's forecast is superior to the backward-looking DSI proposal; PBL's forecast accounts for available sheltering. With regard to the DSIs' assertion that "[t]he Draft ROD's refusal to reduce transmission expenses associated with short-term sales is arbitrary and capricious . . . ," DSI Ex. Brief, WP-02-R-DS-01, at 22, BPA's rate determinations are judicially reviewed for substantial evidence in the 7(i) record, *see* section 1.4, *supra*. Substantial record evidence is cited and explained above.

In their initial brief, Alcoa and Vanalco argued that "BPA has overstated the cost of obtaining transmission capacity necessary for export sales to the Southwest by $32 million per year for the rate period." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 64 (citing without page references two volumes of direct testimony of the Joint DSIs, Shoenbeck and Bliven, WP-02-E-DS/AL/VN-03, and Shoenbeck and Bliven, WP-02-E-DS/AL/VN-06); *see also* Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 35. Alcoa and Vanalco do not provide an explicit rationale for this claim. *See* WP-02-B-AL/VN-01, at 64; *see also* Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 35. In their brief on exceptions, Alcoa and Vanalco specify that it is pages 12 through 18 of the cited DSI testimony that supports their position. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 35. The Joint DSI direct testimony Alcoa and Vanalco cite does contain a $32 million figure. Shoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 12. In the Joint DSI testimony cited, this amount reflected the sum of the DSIs' various proposed adjustments to the PBL transmission expense forecast, including suggested reductions from utilizing prepurchased Intertie transmission rights for grandfathered contract deliveries, maximizing "sheltering," and removal of a forecasted increase in Hourly Non-Firm (HNF) transmission service rates based on a shift from 1 Non-coincidental Demand (NCD) to 12 CP cost recovery. *Id.* at 12-13. Notably, the DSIs reduced this summary amount in their initial brief to an $18 million figure related solely to a suggested revision based on increased sheltering. DSI Brief, WP-02-B-DS-01, at 54-55. To the extent that the DSIs raised in their initial brief issues stemming from the testimony Alcoa and Vanalco cite, those issues are addressed under this issue and in the issues that follow in this section.

Decision

BPA has not modified the transmission expense forecast proposed in the initial proposal to reflect an assumption that BPA would have to procure additional transmission services for only 57 percent of HLH sales and 47 percent of LLH sales; instead, for the final rates BPA includes the elements of the initial proposal relevant to this issue.

Issue 3

Whether PBL should assume for purposes of the transmission expense forecast that unused prepurchased intertie capacity can be used to serve grandfathered contracts.

Parties' Positions

The DSIs state that "[t]he DSI's witnesses testified that staff's transmission expense forecasts were flawed [because, among other things, PBL] was not maximizing use of prepurchased intertie rights . . . ." DSI Brief, WP-02-B-DS-01, at 55; *see also* Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 12-13. The DSIs do not elaborate further or take a position on this issue in their initial brief. DSI Brief, WP-02-B-DS-01, at 55. In their direct testimony, the Joint DSIs asserted that using prepurchased Intertie capacity first to meet the needs of long-term obligations, including an average 459 MW of grandfathered contracts, would reduce transmission expenses by $25.4 million over the rate period. Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 14-15.

BPA's Position

BPA cannot assume that unused prepurchased Intertie capacity can meet the transmission needs of the grandfathered contracts. Pedersen and McRae, WP-02-E-BPA-52, at 3. For grandfathered contracts, which are usually "delivered" contracts, PBL must have a secure path during the term of the contract. *Id.* During the spring months, PBL does not forecast any available surplus Point-to-Point (PTP) transmission. *Id.* Further, the majority of the grandfathered contracts with transmission requirements specify delivery at Nevada-Oregon Border (NOB). *Id.* at 4. Currently, PBL has only 50 MW of surplus PTP on the direct current (DC) Intertie for NOB deliveries in the months of June through October for FY 2003 through 2006--the remainder of the PBL surplus being on the alternating current (AC) Intertie for deliveries at California-Oregon Border (COB). *Id.* This 50 MW part-year surplus is not sufficient to cover the grandfathered contracts. *Id.*

Evaluation of Positions

While the DSIs note that their witnesses testified regarding this issue, they have failed to state and fully develop a position on it in their initial brief. DSI Brief, WP-02-B-DS-01, at 55; *see* Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03 at 12-13. No other party raised this issue in its initial brief.

The position taken by the DSIs in their direct testimony is inconsistent with the facts demonstrated by BPA witnesses Pedersen and McRae.

Decision

PBL will not assume for purposes of the transmission expense forecast that unused prepurchased Intertie capacity can be used to serve grandfathered contracts.

Issue 4

Whether the transmission expense forecast should reflect a predicted increase in the HNF rate based upon a shift from 1 NCD to 12 CP cost recovery.

Parties' Positions

The DSIs note that "BPA . . . agreed to recalculate costs 'without any upward pressure associated with the shift from 1 NCD to 12 CP cost recovery' . . . which should reduce transmission expense by roughly $1.4 million a year, or $7 million over the rate period." DSI Brief, WP-02-B-DS-01, at 55, citing Pedersen and McRae, WP-02-E-BPA-52, at 6.

BPA's Position

The forecasted HNF rate should not include costs associated with the forecasted shift from 1 NCD to 12 CP cost recovery, because the HNF load is not affected by shifting from 1 NCD to 12 CP. Pedersen and McRae, WP-02-E-BPA-52, at 6. Thus, PBL proposed to recalculate the forecasted HNF rate increase without any upward rate pressure associated with the forecasted shift from 1 NCD to 12 CP cost recovery. *Id.*

Evaluation of Positions

PBL agrees with the party's testimony on the methodology for the calculation of the forecasted HNF rate increase. Pedersen and McRae, WP-02-E-BPA-52, at 6. The DSIs accept the decision BPA proposed on this issue in the Draft ROD. DSI Ex. Brief, WP-02-R-DS-01, at 22.

Decision

The forecasted HNF rate increase has been recalculated without any upward rate pressure associated with the forecasted shift from 1 NCD to 12 CP cost recovery.

Issue 5

Whether BPA should modify the transmission expense forecast to reflect reduced levels of prepurchased Intertie capacity due to unfulfilled transmission requests and data base discrepancies.

Parties' Positions

The DSIs note that "In rebuttal, BPA staff indicated that it was 'modifying the level of prepurchased Intertie capacity included in the transmission expense forecast to account for the most current data on the level of prepurchased Intertie capacity available.'" DSI Brief, WP-02-B-DS-01, at 55 (quoting Pedersen and McRae, WP-02-E-BPA-52, at 5). However, the DSIs did not take a position on this issue in their initial brief. *Id.*

BPA's Position

PBL proposed to modify the level of prepurchased Intertie transmission capacity included in the transmission expense forecast to account for the most current data on the level of prepurchased Intertie capacity available. Pedersen and McRae, WP-02-E-BPA-52, at 5. When the initial proposal was developed, PBL had pending transmission requests totaling 600 MW that were counted as prepurchased Intertie transmission. *Id.* The requests totaling 600 MW were not fulfilled, so PBL proposed that they be removed from the transmission expense forecast. *Id.* In conjunction with the transmission requests that were not fulfilled, PBL found discrepancies in the post-2001 period in the data base that tracks the prepurchased transmission inventory compared with what was actually acquired for the same time period; these discrepancies should be corrected. *Id.*

Evaluation of Positions

BPA's proposed modification attempts to reflect costs of prepurchased transmission capacity more accurately by accounting for unfulfilled requests and data base discrepancies. This modification is consistent with the DSIs' stated objective of reducing the PBL transmission expense forecast. *See* DSI Brief, WP-02-B-DS-01, at 55. The DSIs accept the decision BPA proposed on this issue in the Draft ROD. DSI Ex. Brief, WP-02-R-DS-01, at 22.

Decision

BPA has modified the transmission expense forecast presented in the initial proposal to include in the final rates the following amounts of prepurchased Intertie transmission: October 2001 to March 2002--1,610 MW; April 2002 to August 2002--2,005 MW; September 2002 to December 2002--1,605 MW; January 2003 to June 2003--1,405 MW; July 2003 to December 2003--1,305 MW; and from January 2004 through September 2006--1,150 MW.

8.3 General Transfer Agreement (GTA) Expense Issues

Issue 1

Whether BPA should continue existing GTA service to current loads for Federal power deliveries and whether those costs should be borne by BPA's power customers.

Parties' Positions

PPC states, "BPA proposes that its power business line continue existing service under the General Transfer Agreements to preference customer loads currently served through GTAs." PPC Brief, WP-02-B-PP-01, at 42. "PPC supports each of BPA's GTA proposals in this rate proceeding." *Id.* "NRU supports BPA's initial proposal to recover the cost of GTA service for Federal power deliveries through power rates in the 2002-2006 rate period." NRU Brief, WP-02-B-NI-02, at 14.

PPLM states, "To the extent possible . . . the costs associated with GTAs should be directly assigned to the customers who are benefited by the GTAs. When such assignment is not possible, the costs of GTAs associated with the delivery of Federal power should be included in BPA's power rates." PPLM Brief, WP-02-B-PM-01, at 11.

BPA's Position

BPA proposed to continue existing GTA service to current loads for delivery of Federal power through the FY 2002-2006 rate period. 64 Fed. Reg. at 44,328. For GTAs that expire during the rate period, BPA proposed to obtain comparable transfer service under the transmitting utility's open access transmission tariff. Pedersen and McRae, WP-02-E-BPA-28, at 8. BPA proposed that the costs of transfer service for delivery of Federal power will be spread over all PBL power sales; these costs are estimated to be around $52 million per year through the rate period. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 96; Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 49-54.

Evaluation of Positions

In the Subscription ROD, the Administrator decided that, "BPA's initial proposal for the Power Rate Case will include a proposal that GTA costs for Federal deliveries be allocated to the PBL . . . " Subscription ROD, at 135. This commitment was reflected in the power rate case Federal Register Notice, 64 Fed. Reg. 44,318, 44,328 (1999); the Wholesale Power Rate Development Study, WP-02-E-BPA-05; Cherry and Metcalf, WP-02-E-BPA-10, at 7; and Pedersen and McRae, WP-02-E-BPA-28, at 7-8. At the suggestion of customers, BPA agreed to address all GTA-related costs in the power rate case. Cherry and Metcalf, WP-02-E-BPA-10, at 7. As PPC and NRU both note, no party has taken issue squarely with BPA's general proposal to continue providing GTA service for Federal deliveries. PPC Brief, WP-02-B-PP-01, at 42; NRU Brief, WP-02-B-NI-02, at 15. However, PPLM has described BPA's proposal as "the next best solution" to directly assigning the costs of GTA service to the customers that benefit from it. Brooks, WP-02-E-PM-01; PPLM Brief, WP-02-B-PM-01, at 11.

PPLM states, "To the extent possible . . . the costs associated with GTAs should be directly assigned to the customers who are benefited by the GTAs." PPLM Brief, WP-02-B-PM-01, at 11. PPLM's suggestion that GTA costs be directly assigned is tantamount to a suggestion that BPA discontinue providing GTA service altogether. Notably, PPLM has not argued or provided any evidence to demonstrate whether direct assignment of GTA costs is possible. This implies that PPLM is satisfied with what it characterizes as the next best solution: "the costs of GTAs associated with the delivery of Federal power should be included in BPA's power rates." PPLM Brief, WP-02-B-PM-01, at 11.

PPLM cites *Northern States*, 64 FERC ¶ 61,234, 63,379 (1993), for the statement that cost-causation is the fundamental theory of ratemaking at FERC. *Id.* In *Northern States*, the Commission was analyzing whether the service agreements filed by Northern States were just and reasonable under Federal Power Act standards. *See* 64 FERC ¶ 61,234, 63,377. While the FPA does not supply the standards upon which FERC will review BPA's decision with respect to whether the cost of certain Federal power deliveries may be included in power rates, because BPA is not a public utility regulated under the FPA, cost causation has always been an important consideration in BPA ratemaking; but it is not the only consideration. (The applicable standards of review at FERC are provided by the Northwest Power Act. FERC reviews BPA power rates to ensure that power rates "are sufficient to assure repayment of the Federal investment in the [FCRPS] over a reasonable number of years . . . ," and "are based upon . . . total system costs."

16 U.S.C. §7(a)(2). Neither of these standards inherently precludes spreading the cost of GTA service amongst all power customers; FERC has previously approved BPA power rates which included the cost of GTA service under these standards. *See United States Department of Energy--Bonneville Power Admin.*, 80 FERC ¶ 61,118 (1997). PPLM has not argued or provided evidence that BPA's GTA proposal for Federal power deliveries will jeopardize approval under the applicable repayment and total system cost standards.)

Cost-causation is a factor in BPA's GTA proposal. Metcalf and Furst, WP-02-E-BPA-35, at 2. When BPA built the Federal transmission system to deliver Federal power to its preference and DSI customers, BPA chose not to build transmission facilities where it was cost-effective to utilize existing facilities owned by other utilities. *Id.* BPA entered into GTAs to serve preference and DSI customers over these third-party facilities. *Id.* These decisions benefited all BPA customers. *Id.* Therefore, cost-causation principles suggest that it is appropriate for all power customers to share in the costs of GTA service.

The Bonneville Project Act gives the agency additional ratesetting guidance by commanding that BPA rates "shall be established with a view to encouraging the widest possible diversified use of electric energy." 16 U.S.C. §832e. Continuation of GTA service for Federal power deliveries is consistent with BPA's historical practice and helps promote the widespread use of Federal power. 64 Fed. Reg. 44,318, at 44,328 (1999); Pedersen and McRae, WP-02-E-BPA-28, at 7-8; Cherry and Metcalf, WP-02-E-BPA-10, at 7. NRU agrees, stating that, "This practice is both consistent with historical BPA practice and meets BPA's legal obligation to promote widespread use of Federal power." NRU Brief, WP-02-B-NI-02, at 14. Provision of GTA service is grounded in an affirmative obligation to serve BPA's historical preference load and to assist such customers in avoiding unexpected cost shifts during the transition to a competitive market. Pedersen and McRae, WP-02-E-BPA-28, at 8. Thus, the GTAs provide a means of ensuring that these customers receive requirements power service that is comparable to directly served preference customers. *Id.* By putting these customers on comparable terms, BPA encourages the widespread and diversified use of electricity.

Decision

BPA will continue existing GTA service to current loads for Federal power deliveries, and the associated costs, including the costs of open-access transmission service to replace expiring GTAs, will be borne by BPA's power customers. Provisions dealing with GTAs can be found in the Power Subscription Strategy Administrator's Supplemental ROD.

Issue 2

Whether BPA should provide GTA service to new preference customers for deliveries of Federal power.

Parties' Positions

NRU states that it "does not propose to reopen in this rate case the decision in the Subscription ROD not to include in the PBL revenue requirement the cost of GTA service to serve . . . a new public agency. In this regard, NRU also opposes the proposal by witness Ed Sheets that a new tribal utility formed by the Yakamas after the close of the Subscription window be eligible for GTA service." NRU Brief, WP-02-B-NI-02, at 14-15.

UCUT takes the position that unless the revenue requirement includes an amount "sufficient to pay for new preference customers' General Transfer Agreements, or similar power delivery provisions," the BPA proposal would be contrary to law because it includes similar funding for existing preference customers. UCUT Brief, WP-02-B-UC-01, at 10-11. Further, "UCUT considers it more equitable that the Administrator would provide GTA service for new customers but not for existing customers . . ." *Id.* at 17.

"CRITFC and the Yakama Nation recommend that Bonneville increase its revenue requirements by approximately $5 million per year to cover the cost of paying for the General Transfer Agreements of new public utilities, including new tribal utilities." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 53. CRITFC/Yakama "do not support the alternative remedy . . . that all GTA costs be eliminated from Bonneville's revenue requirements." *Id.*

BPA's Position

Under BPA's initial proposal, GTA service for delivery of Federal power would not be available to new preference customers. Pedersen and McRae, WP-02-E-BPA-28, at 8.

Evaluation of Positions

In the Subscription ROD, the Administrator determined that "Service under GTAs will not be available to new preference customers . . ." Subscription ROD, at 130. NRU suggests that this Subscription ROD decision precludes revisiting this issue in the power rate case. NRU Brief, WP-02-B-NI-02, at 15. The limited scope of the 2002 power rate case generally does not allow for rearguing decisions made in the Subscription ROD. 64 Fed. Reg. 44,318, 44,322. However, the scope of the 2002 power rate case specifically does include issues pertaining to "all GTAs and GTA replacement costs for Federal power deliveries . . ." *Id.* at 44,323, 44,328. As manifested above in Issue 1, the over-arching issue of whether or not to continue providing GTA service for Federal deliveries is within the scope of this rate case. Therefore, the scope of this rate case logically includes the subissue of whether new Federal deliveries will be eligible for GTA service or whether this benefit will be reserved for existing preference customers. NRU's reliance on the Subscription ROD is misplaced.

Under BPA's initial proposal, GTA service for delivery of Federal power would not be available to new preference customers. Pedersen and McRae, WP-02-E-BPA-28, at 8. BPA stated that, "Provision of GTA service is grounded in an affirmative obligation to serve BPA's historic preference load and to assist such customers in avoiding unexpected cost shifts during the transition to a competitive market. Thus, the GTAs provide a means of ensuring that these customers receive requirements power service that is comparable to directly served preference customers. The rationale to continue this treatment is not compelling with respect to new load coming into service under FERC's current regulatory regime, which envisions transmission service being provided under open access tariffs." *Id.* Thus, the rationale for BPA's initial proposal to deny new preference customers GTA service for Federal deliveries was based primarily on possible inconsistency with FERC's vision of how transmission service should be provided. BPA's testimony did not attempt to evaluate the impact of this proposal on potential new preference customers.

UCUT and CRITFC/Yakama have addressed the impact of BPA's initial proposal on new preference customers. "Requiring new preference customers to pay costs not paid by existing customers, as well as to subsidize existing customer costs, reduces and may eliminate the benefits of their preference status and places them at an economic disadvantage." UCUT Brief, WP-02-B-UC-01, at 15; *see also* UCUT Ex. Brief, WP-02-R-UC-01, at 3. BPA's initial proposal "act[s] as a disincentive for formation of new preference entities . . . ." UCUT Brief, WP-02-B-UC-01, at 11. "The Yakama Nation's utility's pancaked costs and control area costs would range from $1.75 million to $2.75 million, and these costs have the potential to erase any real cost benefits that would accrue to ratepayers of the Yakama Nation utility . . . ," CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 48-49, and "may make formation of a tribal utility uneconomic and infeasible." *Id.* at 53. The Yakama Nation may save only about $900,000 on its power bill by purchasing power from BPA instead of PacifiCorp. Sheets, WP-02-E-CR/YA-01, at 8. Formation of a tribal utility could help the Yakama Nation protect and maintain its sovereignty; create employment opportunities for tribal members; foster economic development on tribal lands; and help the Nation protect itself from uncertain price and service quality in the face of deregulation. *Id.* at 7.

UCUT and CRITFC/Yakama argue that BPA's initial proposal for GTA delivery of Federal power "is contrary to the following laws: (1) they are not 'uniform' or 'equitable' as required by sections 5(a) and 6 of the Bonneville Project Act, Section 6 of the Preference Act, and sections 9 and 10 of the Transmission System Act; (2) they act as a disincentive for formation of new preference entities as contravenes the intention and history of section 5(a) of the Northwest Power Act; and (3) they contravene the requirement of section 6(k) of the Northwest Power Act requiring the Administrator to insure that benefits shall be distributed equitably consistent with the obligations to particular customer classes." UCUT Brief, WP-02-B-UC-01, at 11; CRITFC/Yakama Brief, WP-02-CR/YA-01, at 48. *See also* UCUT Ex. Brief, WP-02-R-UC-01, at 3; CRTFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 30. The arguments these parties have presented in support of their position do not compel the conclusion that BPA's initial proposal was contrary to law.

UCUT and CRITFC/Yakama cite sections 5(a) and 6 of the Bonneville Project Act, section 6 of the Preference Act, and sections 9 and 10 of the Transmission System Act for the proposition that BPA rates must be uniform and equitable. UCUT Brief, WP-02-B-UC-01, at 12-15; CRITFC/Yakama Brief, WP-02-CR/YA-01, at 50. "UCUT . . . asserts that based on their plain language, . . . BPA organic acts prohibit power rates from being purposely designed to apply differently to similarly situated preference customers." UCUT Ex. Brief, WP-02-R-UC-01, at 3. Essentially, these parties point to the occurrence of the words "uniform" and "equitable" in these statutory subsections and conclude, without substantial analysis of the issue at hand, that the BPA initial proposal violates the statute. Furthermore, while UCUT and CRITFC/Yakama have demonstrated that BPA's initial proposal will have a cost impact on their utility customers, they have not demonstrated that the decision in question amounts to a "rate" as contemplated by the statutory subsections cited. These customers would pay rates from the same applicable rate schedules as any other eligible customer. Nevertheless, UCUT and CRITFC/Yakama have demonstrated that BPA organic statutes do require fairness.

UCUT and CRITFC/Yakama cite section 5(a) of the Northwest Power Act, section 2(b) of the Bonneville Project Act, and section 9 of the Transmission Act for the principle that BPA rates should not provide a disincentive for formation of new preference customers. UCUT Brief, WP-02-B-UC-01, at 15-16; CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 51-52. Congress could have distinguished between new and existing preference customers in enacting the Northwest Power Act, but Congress did not. UCUT Brief, WP-02-B-UC-01, at 15; CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 51. Imposing costs on new customers but not on existing customers is contrary to section 2(b) of the Bonneville Project Act, which requires BPA to "encourage the widest possible use of all electric energy that can be generated and marketed and to provide reasonable outlets, thereof, and to prevent the monopolization thereof by limited groups." UCUT Brief, WP-02-B-UC-01, at 15-16; CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 51. Section 9 of the Transmission Act requires BPA to encourage "the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles." UCUT Brief, WP-02-B-UC-01, at 16; CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 52. The parties point to general statutory guidance without applying it to the matter at issue and then conclude that the initial proposal is contrary to the statute.

UCUT and CRITFC/Yakama state that "discriminatory treatment of new preference customers in favor of existing preference customers with regard to GTA service," is inconsistent with the Northwest Power Act section 6(k) mandate that "the Administrator insures that benefits shall be distributed equitably consistent with the obligations to particular customer classes." UCUT Brief, WP-02-B-UC-01, at 16; CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 52. The parties fail to note that section 6(k) of the Northwest Power Act applies only to conservation and acquisition of resources; section 6(k) prohibits geographical discrimination in allocating the benefits of conservation and resource acquisition. H.R. Rep. No. 96-976, pt. 2, at 293 (1980). The parties do not explain how this section is applicable to the matter in question.

UCUT and CRITFC/Yakama have asserted that BPA's initial proposal would violate several of BPA's organic acts. While these parties have not supported this allegation with the most convincing legal arguments, the parties have pointed to sections of BPA's organic acts that would permit BPA to provide new preference customers with GTA service comparable to that enjoyed by existing preference customers. Furthermore, these parties have provided ample evidence suggesting that fairness dictates that GTA service should be available to new preference customers. These fairness concerns outweigh any perceived inconsistency with FERC's new regulatory requirements for jurisdictional utilities. Moreover, offering GTA service to new preference customers may further FERC's objectives. GTA service "lessens distortions in the market and helps achieve FERC's goal of a freely moving, open-to-all, power market over a large geographic area." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 52 (quoting Scott and Scher, WP-02-E-PN-12, at 12). Making GTA service available to new preference customers will encourage formation of new public agency utilities. In their briefs on exceptions, UCUT and CRITFC/Yakama express support for this decision, as it was proposed in the Draft ROD.

UCUT Ex. Brief, WP-02-R-UC-01, at 3; CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 30.

BPA actively considered supporting the formation of new small public preference customers in the Subscription process. In the Power Subscription Strategy Administrator's Supplemental ROD, BPA determined that it can cover the cost of GTA service or comparable transfer service under open access tariffs for a limited amount of load for new preference customers, within BPA's current GTA budget forecast. Therefore, GTA service will be made available to new preference customers, up to 75 aMW Subscription Supplemental ROD, at 32.

Decision

BPA will provide a limited amount of GTA service or comparable transfer service under an open access tariff for deliveries of Federal power to certain new preference customers, consistent with the Power Subscription Strategy Administrator's Supplemental ROD.

Issue 3

Whether BPA should provide GTA service to preference customers for deliveries of Federal power to annexed load.

Parties' Positions

No party addressed this issue in an initial brief or brief on exceptions.

BPA's Position

Under BPA's initial proposal, GTA service for delivery of Federal power would not be available for preference customers' annexed load. Pedersen and McRae, WP-02-E-BPA-28, at 8.

Evaluation of Positions

Provision of GTA service is grounded in an affirmative obligation to serve BPA's historical preference load and to assist such customers in avoiding unexpected cost shifts during the transition to a competitive market. Pedersen and McRae, WP-02-E-BPA-28, at 8. Thus, the GTAs provide a means of ensuring that these customers receive requirements power service that is comparable to directly served preference customers. *Id.* The rationale to continue this treatment is not compelling with respect to new load coming into service under FERC's current regulatory regime, which envisions transmission service being provided under open access tariffs. *Id.* Therefore, BPA will not provide GTA service to preference customers for deliveries of Federal power to annexed load.

Decision

BPA will not provide GTA service to preference customers for deliveries of Federal power to annexed load.

8.4 Delivery Segment Costs

Issue

Whether any delivery segment costs should be included in the power revenue requirement.

Parties' Positions

PNGC argues that $6 million of delivery segment costs must be retained in power rates on a rolled-in basis. PNGC Brief, WP-02-B-PN-01, at 27.

BPA's Position

In its initial proposal, BPA proposed that PBL would continue to pay for delivery segment costs only when PBL is the transmission customer using those facilities. Cherry and Metcalf, WP-02-E-BPA-10, at 7. The portion of delivery segment costs included in power rates upon settlement of the 1996 rate case would not be included in power rates for the 2002-2006 rate period. *Id.*

Evaluation of Positions

BPA stated that, "[t]he decision to assign a portion of the delivery segment costs to the power rates in 1996 was a condition of the settlement of the 1996 transmission rate case. This decision represented a phasing-in of the new segmentation and transmission rate design methodologies. It also gave customers time to purchase delivery facilities under the sale of facilities policy." Cherry and Metcalf, WP-02-E-BPA-10, at 7. BPA described its decision to decide delivery segment issues such as "which facilities are in the segment and how the delivery charge is designed" in the transmission rate case, as an attempt to comply with FERC unbundling principles. Pedersen and McRae, WP-02-E-BPA-52, at 6-7. BPA stated that retaining delivery segment costs in the power revenue requirement is not consistent with cost/price linking or functional unbundling. *Id.* at 7. BPA acknowledged that unbundling may affect some customers more than others, but pointed out several areas where BPA has already attempted to mitigate the effects of unbundling, including caps on the Demand Charge and the Load Variance Charge, continuation of the Low Density Discount (LDD), and relief for customers with high irrigation loads. *Id.*

PNGC notes that some customers will see dramatic cost increases under BPA's initial proposal. PNGC Brief, WP-02-B-PN-01, at 27. For example, PNGC testified that Lane Electric could expect a 4-6 percent increase in its overall revenue requirement based on this single issue. *Id.;* Crincklaw and Wiedl, WP-02-E-PN-05, at 3. PNGC stated that it has not always been practical to mitigate delivery segment cost increases by purchasing substations. *Id*. at 2. PNGC does not view BPA's mitigation efforts, such as caps on the Demand Charge and the Load Variance Charge and continuation of the LDD, as sufficient. PNGC Brief, WP-02-B-PN-01, at 27-28. PNGC believes that, "It is fair to have power customers continue to pay for part of these costs because, in this rate case, BPA is melding the costs of system augmentation needed to serve IOU customers and DSI customers with the cost of serving Preference Customers," and customers who pay the delivery charge are paying for this augmentation. *Id.*

PNGC has demonstrated the substantial impact the initial proposal could have on particular customers. The $6 million of annual delivery costs included in the 1996 power revenue requirement significantly mitigated rate shock for delivery segment users. Crincklaw and Wiedl, WP-02-E-PN-05, at 1-2. However, BPA's interest in offering unbundled rates and linking costs to causation is consistent with FERC efforts to promote competitive wholesale power markets, and therefore is substantial. In an effort to balance these competing principles, BPA will continue to include $2 million of delivery costs per year in the power revenue requirement for the first two years of the 2002-2006 power rate period.

The costs associated with the delivery facilities used by GTA customers were included in the delivery segment in the 1996 transmission rates. 1996 ROD, WP-96-A-02, at 409, 422. Definition of the delivery segment is reserved for the transmission rate case. Cherry and Metcalf, WP-02-E-BPA-10, at 7. However, the initial transmission rate case proposal does not include low voltage GTA facilities in the Delivery segment. *See* Transmission Rate Study, TR-02-E-BPA-03, at 16, C1-C4 (not including GTA PODs as subject to the Utility Delivery Charge). Thus, PBL cannot expect to receive credit from TBL in the 2002-2006 rate period for these costs. Instead, PBL intends to develop a rate to collect these costs from the customers that utilize these facilities. While all GTA issues were intended to be addressed in the power rate case, Cherry and Metcalf, WP-02-E-BPA-10, at 7, PBL did not learn of the TBL proposal in time to develop and propose a specific rate to recover these costs within the normal course of this proceeding. Therefore, BPA will conduct a separate rate proceeding for this purpose.

Decision

For the first two years of the FY 2002-2006 rate period, BPA includes $2 million annually in the power revenue requirement to be used to mitigate the effects of unbundling on delivery segment customers. The power revenue requirement does not include any other costs of delivery facilities. More specifically, the costs of low voltage delivery facilities used by GTA customers are not included in the power revenue requirement; BPA will conduct a separate rate proceeding to develop a rate to collect these costs from the GTA customers that utilize these facilities.

8.5 Generation Inputs for Ancillary Services

Issue 1

Whether BPA should establish in the power rate case a minimum percentage of generation inputs for ancillary services that the TBL would be required to purchase from the open market through a competitive bid process, or, in the alternative, establish a market price cap for PBL-supplied generation inputs.

Parties' Positions

PPLM states that BPA should "establish a minimum percentage of [generation inputs for] ancillary services that the TBL would be required to purchase from the open market through a competitive bid process, to the extent that the rates for such [generation inputs for] ancillary services do not exceed the PBL's cost-based rates for the same services." PPLM Brief, WP-02-B-PM-01, at 1. Alternatively, PPLM proposes that "if BPA declines to implement PPLM's proposed auction approach, BPA should now establish a market price cap for PBL-supplied generation inputs and prohibit the PBL from recovering from the TBL any related shortfall." *Id.* at 10.

BPA's Position

BPA proposed to set a fixed inter-business line charge for the generation input to the generation supplied reactive power ancillary service. Cherry and Metcalf, WP-02-E-BPA-10, at 5. This charge will be used in developing the portion of the transmission revenue requirement associated with the reactive power ancillary service in the transmission rate case. *Id.* Under the initial proposal, TBL would be required to purchase this reactive power generation input from PBL at the fixed inter-business line charge. *Id.*

BPA proposed cost-based caps for the per-unit inter-business line charge for capacity-based generation inputs to the regulation service and operating reserves ancillary services. *Id.* at 4. PBL used these unit costs and an estimate of unit sales to TBL to forecast revenue from sales of these products. *Id.* at 4-5. Under the initial proposal, TBL would not be required to purchase these generation inputs from the PBL, and PBL may discount the unit charge for these products. *Id.* at 4.

BPA proposed a market-based per-unit inter-business line charge for energy used as a generation input to the energy imbalance ancillary service and for energy utilized when operating reserves are called upon. DeClerck *et al.*, WP-02-E-BPA-26, at 11, 15. BPA had insufficient information to forecast revenue from these sources. *Id.* Under the initial proposal, TBL would not be required to purchase these services from PBL, but TBL will be charged the specified market-based rate if and when it does make such purchases. *Id.*

Evaluation of Positions

With the exception of the generation input to the generation-supplied reactive power ancillary service, BPA proposed methodologies to determine the unit cost of energy and capacity supplied by the PBL to the TBL as generation inputs for ancillary services. Cherry and Metcalf, WP-02-E-BPA-10, at 5. With the same exception of the generation input to the generation supplied reactive power ancillary service, BPA did not propose to require TBL to purchase any particular amount of generation inputs for ancillary services from the TBL. *Id.* at 4-5. With respect to all other generation inputs for ancillary services, PBL has forecasted the amount of particular generation inputs for ancillary services it expects to sell to TBL, and has used these estimates as credits in the power revenue requirement. *Id.* PPLM argues that by forecasting particular amounts of PBL revenue from these sales, and because of past practice, BPA has indicated an intent that PBL will continue to be TBL's sole supplier of generation inputs for ancillary services. PPLM Brief, WP-02-B-PM-01, at 2-3. This assertion is contrary to clear statements in BPA testimony. TBL is free to purchase from other suppliers generation inputs for the generation-supplied reactive power ancillary service in excess of those proposed to be supplied by PBL. TBL is free to acquire generation inputs for other ancillary services from any supplier TBL chooses in any amounts meeting TBL's requirements.

BPA's initial proposal sought to establish parameters governing the price PBL would charge TBL for generation inputs. In contrast, PPLM states that BPA should "establish a minimum percentage of [generation inputs for] ancillary services that the TBL would be required to purchase from the open market through a competitive bid process . . ." PPLM Brief, WP-02-B-PM-01, at 1. Thus, PPLM's proposal attempts to define the method of sourcing TBL will use to procure generation inputs. As such, PPLM's auction proposal addresses matters well beyond the scope of the power rate case. "[T]he scope of the power rate case does not include . . . BPA's rates for transmission and ancillary services that will be marketed by the [TBL]." 64 Fed. Reg. at 44,323. PPLM's proposal would be more appropriately raised in the transmission rate case.

Alternatively, PPLM proposes that if BPA "continues to require that the TBL purchase all of its generation inputs for ancillary services from the PBL," PPLM Brief, WP-02-B-PM-01, at 9, "BPA should now establish a market price cap for PBL-supplied generation inputs and prohibit the PBL from recovering from the TBL any related shortfall." *Id.* at 10. As noted above, BPA is not requiring TBL to purchase all of its generation inputs for ancillary services from the PBL. Moreover, PPLM fails to explain how BPA would satisfy cost recovery requirements, should BPA adopt its proposal and find that costs exceed market prices. *See* 16 U.S.C. §839e(a)(2)(B) (requiring BPA rates to be based upon total system costs).

Decision

BPA did not establish in the power rate case a minimum percentage of generation inputs for ancillary services that the TBL would be required to purchase from the open market through a competitive bid process. PBL sales of generation inputs for ancillary services to TBL will be governed by the criteria BPA proposed, as summarized above; BPA will not impose a market-based cap on the per-unit inter-business line charges for generation inputs for ancillary services.

Issue 2

Whether BPA must develop an inter-business line charge for the reactive power generation input by strictly adhering to either a capability method or an actual use method, as proposed by the IOUs, or whether BPA may develop that charge based upon a capability methodology, but still take into account the normal operation of FCRPS generators, as BPA has proposed.

Party's Positions

"BPA has inappropriately mixed an 'actual use' approach and 'capability' approach in determining that 19 percent of the electrical plant should be allocated to the Transmission Business Line ("TBL") for reactive power." Schlect and Banaghan, WP-02-E-AC/GE/IP/MP/PL/PS/EN-08, at 2; IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 80; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 60.

BPA's Position

BPA has proposed a capability method, with certain elements of that methodology accounting for the normal operation of FCRPS hydro generation units. DeClerck *et al.*, WP-02-E-BPA-51, at 2.

Evaluation of Positions

The IOUs have argued that BPA must choose between: (1) an actual use method; or (2) a capability method "based upon the real and reactive power capabilities of electrical generation components . . . " Schlect and Banaghan, WP-02-E-AC/GE/IP/MP/PL/PS/EN-08, at 3. The IOUs describe the "actual use" method as one "based upon either real data or upon a comprehensive set of reasonable assumptions to estimate the actual use of such components." *Id.* The IOUs argue that BPA has inappropriately mixed the actual use and capability methods to determine the ratio used to allocate the costs of electrical generation components between real and reactive power production. *Id.* at 4. The IOUs argue that, once a "capability method" is chosen, "[a]llowing one or two assumptions based upon actual use principles to be applied . . .,such as using the available reactive *capability* when a hydro unit is operated near peak efficiency, simply provides for the 'cherry picking' of assumptions to produce an arbitrarily higher or lower allocation factor." *Id.* at 5 (emphasis added). The IOUs state that, "It would be appropriate for BPA to consider peak efficiency operations when taking a comprehensive cost causation approach based upon normal operations or *actual use* of electrical generation components." *Id.* at 7. But to be consistent with the choice of a capability method, the IOUs conclude that BPA must ignore the effects of peak efficiency operations and instead use the rated power factor, based on the nameplate rating, to allocate costs. *Id.* at 5.

Both BPA and the IOUs accept using the allocation ratio that results from the relationship between apparent, real, and reactive power to determine the allocation of costs of electrical generation components between real and reactive power production. *See* Schlect and Banaghan, WP-02-E-AC/GE/IP/MP/PL/PS/EN-08, at 3-4. BPA takes the position that it has not inappropriately mixed capability and actual use methods to arrive at that ratio. DeClerck *et al.*, WP-02-E-BPA-51, at 2. The IOUs insist that there is a stark distinction between capability and actual use methodologies and that an appropriate allocation will result only from rigid application of either methodology, but not from a methodology that makes use of principles from both. Schlect and Banaghan, WP-02-E-AC/GE/IP/MP/PL/PS/EN-08, at 3; IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 80; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 60. BPA has taken a capability methodology approved by the Commission for application to a thermal system, *see Southern Company*

Services, Inc., 80 FERC ¶ 61,318 (1997); *see also* IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 60, and adapted it to the operational realities of the FCRPS in order to obtain a fair allocation of costs, based upon the capability of the FCRPS hydro generation under normal operating conditions, DeClerck *et al.*, WP-02-E-BPA-51, at 2. Thus, BPA should not be confined to blind application of a methodology the Commission approved for use with regard to a thermal system, without taking into account hydrosystem idiosyncrasies, when to ignore those differences would yield unfair results.

Decision

BPA will develop an inter-business line charge for the reactive power generation input based upon a capability methodology, but will take into account the normal operation of FCRPS generators, where to do so is necessary to achieve a fair result.

Issue 3

Whether PBL should develop a charge for the reactive power generation input based on power factors corresponding to nameplate ratings instead of normal operations.

Parties' Positions

Should BPA choose to use a capability method to develop the inter-business line charge for the reactive power generation input, the IOUs propose to allocate the percentage of electrical generation equipment used in the production of reactive power and voltage control through the use of a weighted average system power factor, based on the machines' nameplate ratings. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 80 (arguing for use of the 8 percent hydro unit allocation factor developed from the rated power factor (nameplate) analysis); Schlect and Banaghan, WP-02-E-AC/GE/IP/MP/PL/PS/EN-08, at 5; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 60 (clarifying that the IOUs' proposal to use power factors based upon nameplate ratings is proposed as a remedy to perceived deficiencies in BPA's proposal, which the IOUs argue inappropriately mixes elements of actual use and capability methodologies).

BPA's Position

Maintaining that it has chosen a capability method to develop the inter-business line charge for the reactive power generation input, WP-02-E-BPA-51, at 2, BPA has selected a power factor defined at a point near peak efficiency of the hydro generator units, corresponding to their normal operating point. DeClerck *et al.*, WP-02-E-BPA-26, at 5-6. BPA agrees that the power factor associated with operation of WNP-2 should be the rated power factor of the nuclear units. DeClerck *et al.*, WP-02-E-BPA-51, at 9.

Evaluation of Positions

The focal point of disagreement between BPA and the IOUs is whether, once a capability method has been chosen, the allocation ratio must be developed from a power factor based upon machine nameplate ratings, or whether the allocation ratio can be developed from a power factor corresponding to normal operations of the machine instead. The IOUs imply that nameplate power factors necessarily identify the correct reactive capability of the machine to base such an allocation on. BPA has chosen a power factor corresponding to actual operations because BPA believes this power factor results in a fair allocation of costs. The IOUs argue that such an allocation is arbitrary; thus, BPA must use the only available non-arbitrary power factor, which, the IOUs argue, is the nameplate power factor. As discussed below, BPA has presented credible evidence that its choice of power factor is not arbitrary and that use of the nameplate power factor suggested by the IOUs would not fairly allocate costs between real and reactive power production.

Should BPA choose to use a capability method to develop the inter-business line charge for the reactive power generation input, the IOUs propose to allocate the percentage of electrical generation equipment used in the production of reactive power and voltage control through the use of a weighted average system power factor, based on the machine's nameplate ratings. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 80 (arguing for use of the 8 percent hydro unit allocation factor developed from the rated power factor (nameplate) analysis); Schlect and Banaghan, WP-02-E-AC/GE/IP/MP/PL/PS/EN-08, at 5; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 60 (clarifying that the IOUs' proposal to use power factors based upon nameplate ratings is proposed as a remedy to perceived deficiencies in BPA's proposal, which the IOUs argue inappropriately mixes elements of actual use and capability methodologies). The IOUs argue that the allocation factor resulting from this methodology should be no higher than 8 percent for hydro units and 5 percent for WNP-2. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 80. The IOUs note that BPA has defined reactive capability by way of the operating range it selects based on real power production considerations, and then BPA allocates reactive costs based on 100 percent of this reactive capability. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 80, n. 215. Thus, the IOUs claim that BPA has "inappropriately mixed 'actual use' and a 'capability'" in calculating the cost of generation-supplied reactive power. *Id.* at 79-80. The IOUs argue that this "inconsistent approach results in overstating the cost of generation-supplied reactive power" by about $16 million. *Id.* at 80.

BPA has not mixed capability and actual-use methods in allocating the costs of hydro generation electrical facilities to generation inputs for generation-supplied reactive power and voltage control. DeClerck *et al*., WP-02-E-BPA-51, at 2. BPA's approach to calculate the weighted average system power factor is based on a capability method rather than an actual-use method. *Id.* While BPA is using a capability method, elements of BPA's proposed methodology do account for the normal operation of the hydro generation units. *Id.* Hydro generation units are normally constrained to operate below nameplate ratings due to a limited water supply, plant operating restrictions, and fish passage limitations. *Id.* Therefore, BPA is defining the capability of the hydro generation units to provide reactive power using points on the generator capability curves corresponding to normal operations, rather than nameplate ratings. *Id.* This methodology yields a capacity-weighted average power factor of 0.90 for the FCRPS hydro units, DeClerck *et al.*, WP-02-E-BPA-26, at 5, with a corresponding allocation factor of 19 percent, *Id.* at 6.

The general reactive power cost allocation methodology at issue here was approved by the Commission in *Southern Company Services, Inc.*, 80 FERC ¶ 61,318 (1997). As the IOUs point out, the system at issue in *Southern Company* consisted primarily of thermal generation which is usually operated near nameplate ratings. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 63. Thus, using a nameplate rating to define the allocation factor for thermal units may be appropriate for a thermal system. The Commission has accepted that "a generator nameplate rating specifies the maximum rate that power can be generated by the unit, on a continuous basis without overheating." City of Seattle, Washington, Project No. 2144-012, 53 FERC ¶ 63,015 at 65,153 (1990). Unlike thermal generation, FCRPS machines are constrained such that they rarely operate outside of the peak efficiency band, which, as the IOUs point out, "is at a point below the nameplate rating resulting in higher reactive capability than at the nameplate rating." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 64. While arguing for a contrary result, the IOUs appear to admit that the reactive power capability of FCRPS hydro generation is increased because it operates within the peak efficiency band.

Many FCRPS machines that provide significant reactive power support have a rated power factor of, or approaching, unity. DeClerck *et al.*, WP-02-E-BPA-51, at 5. Machine nameplate ratings of unity correspond to allocations of costs to reactive power production equaling zero. *Id.* Thus, allocations based on the IOUs' proposal would not capture the full value of the reactive capability the FCRPS hydro units provide for transmission reliability. Indeed, for some machines, the IOUs' proposal would not capture any of that value. The BPA proposal will result in a fair cost allocation because the BPA proposal more accurately reflects the reactive capability of the hydro units during normal operations.

BPA and the IOUs agree on the methodology for choosing the WNP-2 power factor and allocation percentage. WNP-2 is primarily a base-loaded plant. DeClerck *et al.*, WP-02-E-BPA-51, at 9. BPA agrees that the power factor associated with operation of WNP-2 should be the rated power factor of the nuclear units. *Id.* Because nuclear plants are normally base-loaded near their nameplate ratings, the rated power factor most accurately describes the capability of the nuclear units to provide reactive power during normal operation. *Id.*

Decision

The inter-business line charge for the generation-supplied reactive power generation input is based upon power factors and allocation percentages corresponding to normal operations.

Issue 4

Whether PBL should charge TBL for the generation-supplied reactive power generation input based on the entire reactive capability of the FCRPS hydro projects.

Parties' Positions

The IOUs argue that "because BPA chose to develop the generation inputs based on an inconsistent methodology using actual use to derive the real power inputs . . ., BPA should not allocate the costs of 100 percent of the reactive capability of the FCRPS [to the inter-business line charge for the reactive power generation input].” IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 63.

BPA's Position

BPA proposed to charge TBL for the generation-supplied reactive power generation input based on the entire reactive capability of the FCRPS hydro projects, because all of that capability is required at some point in time to support transmission system reliability. DeClerck *et al.*, WP-02-E-BPA-51, at 7-9; DeClerck *et al.*, WP-02-E-BPA-26, at 3-4.

Evaluation of Positions

The IOUs state that, “Because of the relationship between real and reactive power and the method chosen by BPA to determine the percentage of costs allocated to TBL, the result of BPA’s methodology is to allocate an arbitrarily high percentage of costs to transmission customers.” IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 64. Thus, the IOUs state that “BPA proposes to allocate costs for reactive power to be based on reactive capability even though this reactive power support is not needed or used by TBL.” IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 81. Further, “BPA proposes to charge TBL for all . . . of the reactive power capability of the Federal power system, 100 percent of the time.” *Id.* The IOUs conclude that, “BPA does not require the reactive capability for which it proposes to charge TBL,” based in part upon admissions by BPA witness DeClerck on cross examination that the “times and places where a hundred percent of the reactive capability is needed are limited both in time and in particular locations.” *Id.* at 81-82, quoting Tr. 219. Further, the IOUs state that TBL’s Reactive Power Margin Criteria do not require “such an allocation.” IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 82. In their brief on exceptions, the IOUs clarify that “because BPA chose to develop the generation inputs based on an inconsistent methodology using actual use to derive the real power inputs . . . , BPA should not allocate the costs of 100 percent of the reactive capability of the FCRPS [to the inter-business line charge for the reactive power generation input].” IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 63.

BPA has determined that the transmission system is usually curtailed due to reactive power demands on the transmission system. DeClerck *et al.*, WP-02-E-BPA-51, at 7. Hydroplant operators are routinely instructed by BPA dispatchers to put more hydro generating units online to provide additional reactive power to support transmission reliability, or to adhere to voltage schedules that are provided by TBL dispatchers. *Id.* TBL has a reactive power monitoring system to maintain reactive power margins (determined by TBL’s Reactive Margin Criteria) and has stated in their rate case workshops that there are times when 100 percent of the reactive power available from BPA hydro generating units at a particular location is needed. *Id.*

BPA has made reasonable assumptions for the amount of reactive power actually needed to support transmission system reliability. DeClerck *et al.*, WP-02-E-BPA-51, at 7. BPA considered the fact that the available reactive capability of the hydro generating units is often greater than the required reactive power needed to support transmission system reliability at particular locations and points in time. *Id.* at 8. However, a transmission system operator must plan for and meet the maximum reactive needs of the transmission system during a disturbance.

Id. It is essential for sufficient reactive power capability to be available, even if it is needed for only short periods of time. *Id.* This demonstrates that FCRPS reactive demands exceed FCRPS hydro reactive capability on at least some occasions. Therefore, all of the reactive capability of the FCRPS hydro projects is required to support transmission system reliability, because that capability must stand ready to provide reactive support when contingencies arise without warning. DeClerck *et al*., WP-02-E-BPA-51, at 7-9; DeClerck *et al*., WP-02-E-BPA-26, at 3-4.

Decision

PBL will charge TBL for the generation-supplied reactive power generation input based on the entire reactive capability of the FCRPS hydro projects.

Issue 5

Whether BPA should adopt in this proceeding a unit charge for the generation inputs to the generation-supplied reactive power ancillary service and a corresponding revenue forecast, instead of a fixed charge for reactive power generation inputs.

Parties' Positions

The IOUs "argue that it is inappropriate for PBL to determine, in the power rate case, a fixed cost for generation-supplied reactive power." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 64. "Instead, . . . BPA should in this proceeding adopt only a unit charge for generation-supplied reactive power." *Id.* at 65.

BPA's Position

BPA has chosen an allocation method based on reactive capability under normal operating conditions. DeClerck *et al.*, WP-02-E-BPA-51, at 2. A core assumption of BPA's methodology is that all of the reactive capability of FCRPS hydro facilities is necessary to support the transmission system. *Id.* at 7-8. Thus, BPA did not find it necessary or worthwhile to perform the rigorous analysis required to determine the exact reactive power requirements imposed by transmission system reliability. *Id.* Development of a per-unit charge is unnecessary, because BPA proposes that PBL will charge TBL a fixed charge for all of the reactive capability of the FCRPS.

Evaluation of Positions

The IOUs suggest that "BPA should in this proceeding adopt only a unit charge for generation-supplied reactive power," and suggest that PBL forecast revenues from TBL based upon this unit charge. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 83. The IOUs have argued that BPA must choose between: (1) an actual use method, or (2) a capability method "based upon the real and reactive power capabilities of electrical generation components . . . " Schlect and Banaghan, WP-02-E-AC/GE/IP/MP/PL/PS/EN-08, at 3. The IOUs describe the "actual use" method as one "based upon either real data or upon a comprehensive set of reasonable assumptions to estimate the actual use of such components." *Id.* However, the IOUs' proposal that BPA develop a unit charge for generation-supplied reactive power first appears in the IOUs' initial brief. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 83. While the IOUs have argued that BPA inappropriately mixes elements of actual use and capability methods, the IOUs did not advocate that BPA choose an actual use method until filing their initial brief. In fact, the IOUs have acknowledged that because BPA does not track reactive power usage, it is not possible "to determine the extent to which generators are dispatched to provide reactive support." Schlect and Banaghan, WP-02-E-AC/GE/IP/MP/PL/PS/EN-08, at 13. Thus, the IOUs have not supported their proposal with an explanation of how it could be implemented.

In their brief on exceptions, the IOUs "argue that it is inappropriate for PBL to determine, in the power rate case, a fixed cost for generation-supplied reactive power, because to do so predetermines the amount of such reactive power TBL will purchase from PBL for transmission operations." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 64. "Rather, TBL, not PBL, should determine how much reactive it needs and from where the reactive should be purchased." *Id.* (citing IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 82). This proposal, originating in the IOUs' briefs, assumes that it is practicable to develop a per-unit inter-business line charge for the reactive power generation input. There is no record evidence to support this proposal. Furthermore, it is important to note that "[t]he initial proposal was developed with input from both business lines . . . The proposals and recommended decisions are made by BPA, not by either business line." Cherry and Metcalf, WP-02-E-BPA-10, at 6. In the power rate case, BPA is determining the amount of an inter-business line charge to account for the annual cost of generator-supplied reactive power capability, as a generation input provided by the PBL to the TBL. *Id.* at 5. In the transmission rate case, TBL will develop a unit-cost rate for the generation-supplied reactive power ancillary service. *Id.*

Decision

BPA has adopted in this proceeding a fixed inter-business line charge to TBL for the reactive power generation input.

Issue 6

Whether the per-unit charge for the operating reserves generation input should be subject to the CRAC.

Parties' Positions

The HLFG argued that the per-unit charges for operating reserves generation inputs should be subject to CRAC. Koehler *et al.*, WP-02-E-HL-01, at 36.

In its initial brief, PGE states that, "Adopting the HLF Group recommendations will better effectuate both of the competing policy goals of sending appropriate market price signals and mitigating rate impacts." PGE Brief, WP-02-B-GE-01, at 12. PGE notes that the HLFG recommendations included application of the CRAC to the operating reserves generation input. *Id.* at 11, n. 12.

WPAG stated that "BPA should exclude CRAC from the internal transfer price of operating reserves . . . " Cross *et al.*, WP-02-E-WA-02, at 5, 59-60.

In its brief on exceptions, PGP states that "PGP takes exception to the Administrator's draft decision not to adopt Bonneville's suggested proposal with respect to the per unit charge for operating reserves generation input." PGP Ex. Brief, WP-02-R-PG-01, at 13. PGP states that, "Bonneville has offered an alternative that would increase the per unit cost for operating reserves generation input to account for the forecasted probability that CRAC will trigger [in] the upcoming rate period." *Id.* at 14.

<u>BPA's Position</u>

Applying CRAC to an inter-business line charge such as the operating reserves generation inputs is inappropriate. DeClerck *et al.*, WP-02-E-BPA-51, at 10.

<u>Evaluation of Positions</u>

HLFG argued that, because the allocated costs and revenue credits for operating reserves generation inputs are based on the same forecasted costs and revenue credits that go into BPA's power rates, the per-unit charges for operating reserves generation inputs should be subject to the CRAC. Koehler *et al.*, WP-02-E-HL-01, at 36. Otherwise, the result may be: "(1) an understatement of the pricing of TBL-supplied Operating Reserves over time, which could cause; or (2) an inequity between the wheeling of Federal and non-Federal power." *Id.* However, it would be inadequate simply to "apply the percentage increase resulting from the CRAC to the internal transfer price, [because] this could overstate the appropriate increase in the internal transfer price . . . " *Id.* at 39. Thus, HLFG proposed "that BPA track the actual net costs associated with the generation assigned to Operating Reserves and increase the internal transfer price proportionately whenever the CRAC triggers." *Id.* HLFG asserts that BPA's new accounting system should be able to track the "actual net costs of generation." *Id.*

In theory, applying the CRAC to the inter-business line charge for operating reserves could promote parity between BPA's posted rates and the charge to the TBL for generation inputs to operating reserves, as HLFG suggested. *See* Koehler *et al.*, WP-02-E-HL-01, at 36-39; DeClerck *et al.*, WP-02-E-BPA-51, at 10. However, under HLFG's proposal, proper application of the CRAC to achieve this parity would require tracking actual net costs of generation. Koehler *et al.*, WP-02-E-HL-01, at 39. HLFG suggested that BPA's new accounting system should be able to track these costs. *Id.* However, BPA states that its systems will not be capable of tracking actual net costs of generation. DeClerck *et al.*, WP-02-E-BPA-51, at 10. In addition, inserting a CRAC charge into TBL's risk portfolio via the inter-business line charge for generation inputs to operating reserves seems to add unnecessary complexity to the overall BPA risk management program. *Id.*

In rebuttal testimony, BPA mentioned an alternative method of adding forecasted CRAC costs to the operating reserves generation input and noted that BPA staff members had discussed this alternative. DeClerck, *et al.*, WP-02-E-BPA-51, at 11. This alternative involved attaching an adder to the per-unit cost of operating reserves that would compensate PBL based on the probability that CRAC will trigger during the rate period, and a forecast of the CRAC increase. *Id.* BPA did not offer support for this alternative because, while this alternative mitigated an implementation problem, it does not alleviate certain inter-business line cost recovery issues. *Id.* BPA made clear that it was not BPA's intent to include a CRAC recovery component in the inter-business line charge for operating reserves generation inputs. *Id.* In its brief on exceptions, PGP characterizes this alternative as "Bonneville's proposal" and argues that the alternative should be adopted because "[t]here is no evidence on the record that Bonneville's alternative . . . is unworkable or has other fatal flaws." PGP Ex. Brief, WP-02-R-PG-01, at 13, 15. No party advocated this alternative in testimony or in their initial briefs; this alternative was not part of BPA's proposal. Moreover, BPA made clear that this alternative mitigated only some of the problems associated with assessing CRAC to the inter-business line charge for operating reserves generation inputs. DeClerck *et al.*, WP-02-E-BPA-51, at 11. Therefore, BPA will not utilize this alternative method.

<u>Decision</u>

BPA will not subject the per-unit charge for the operating reserves generation input to the CRAC. BPA will not attach an adder to the per-unit charge for the operating reserves generation input to recover forecasted CRAC costs.

<u>Issue 7</u>

Whether the inter-business line charges for generation inputs to ancillary services should include the costs of renewables and conservation programs, the costs of nonperforming assets, or Trojan decommissioning costs.

<u>Parties' Positions</u>

PPLM states that, "No costs of nonperforming assets should be included in the pool of costs from which the costs of ancillary services are derived." PPLM Brief, WP-02-B-PM-01, at 13.

WPAG asserted that "BPA has erred by excluding certain costs from the pool of costs assigned to ancillary services." These costs are "the costs of nonperforming assets (WNP-1 and WNP-3), decommissioning costs for the Trojan plant and conservation and renewable resource programs . . . " Cross *et al.*, WP-02-E-WA-01, at 24.

<u>BPA's Position</u>

BPA proposed to allocate costs to the Operating Reserves generation input by using an embedded cost methodology based on the cost of the hydro projects used to meet operating reserve obligations on the system. DeClerck *et al.*, WP-02-E-BPA-26, at 9. BPA proposed to allocate costs to the regulating reserves generation input by using an embedded cost methodology based on the cost of the hydro projects used to meet the regulating reserve obligations of the system; these consist of the 10 hydro projects that are equipped with AGC. *Id.* at 13. BPA proposed that both of these methodologies would exclude the costs of the nonperforming assets (including WNP-1, -3, and Trojan decommissioning), and conservation. *Id.* at 10, 13.

Evaluation of Positions

BPA stated that the costs of nonperforming assets and conservation should be excluded from the cost of the operating reserves and regulating reserves generation inputs, because these assets and programs do not directly contribute to meeting the BPA Control Area operating reserves and regulating reserves obligations. DeClerck *et al.*, WP-02-E-BPA-26, at 10, 13. WPAG acknowledged "that the costs of nonperforming assets and Trojan decommissioning do not contribute directly to the costs of providing ancillary services." Cross *et al.*, WP-02-E-WA-01, at 25. However, WPAG argued that "these costs do not contribute directly to the production of real power . . . " or to "any of the products that the power system produces." *Id.* WPAG compared these costs to administrative and general costs, such that all power system users should share in them. *Id.* WPAG argued that conservation and renewables programs reduce the need for additional generation, which reduces the need for ancillary services, such that a portion of the cost of these programs should be included in the ancillary services generation inputs costs. *Id.* at 26.

PPLM states that "BPA does not dispatch its base-loaded plants to provide operating or regulating reserves." PPLM Brief, WP-02-B-PM-01, at 13. "If they were operating, it is likely that both WNP-1 and WNP-3 (BPA's 'nonperforming assets') would be dispatched as base-loaded plants. Therefore, their costs should not be used as generation inputs for spinning reserve, supplemental reserve, or load regulation services." *Id.* at 13-14. Because Trojan is located outside the BPA control area, and because it would probably be base-loaded were it still operating, Trojan decommissioning costs are not properly included in the costs of ancillary services generation inputs. *Id.* at 14. With respect to including the cost of conservation and renewables, PPLM states that reductions in transmission demand incidental to conservation or renewable programs are very location-specific. *Id.* at 12, 14. PPLM states that attempting to determine what percentage could be assigned to transmission would need to be done on a resource-by-resource basis. Brooks, WP-02-E-PM-09, at 2. The costs of performing this analysis "would likely exceed the benefits of doing so." *Id.*

In its testimony, WPAG raised the issues discussed above. Cross *et al.*, WP-02-E-WA-01, at 24-26. However, WPAG failed to raise these issues in its initial brief. WPAG Brief, WP-02-B-WA-01.

Decision

The inter-business line charges for generation inputs to ancillary services do not include the costs of renewables and conservation programs, the costs of nonperforming assets, or Trojan decommissioning costs.

Issue 8

Whether BPA should assess TBL an annual inter-business line charge for generation dropping provided by PBL.

Parties' Positions

No party raised this issue in an initial brief or brief on exceptions.

BPA's Position

BPA proposed to assess TBL an annual inter-business line charge for generation dropping provided by PBL. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 84-87. *See also* DeClerck *et al.*, WP-02-E-BPA-26, at 16-17.

Evaluation of Positions

Generation dropping is a Remedial Action Scheme (RAS) that the PBL provides to the TBL for purposes of transmission system reliability. DeClerck *et al.*, WP-02-E-BPA-26, at 16-17. PBL provides this service by dropping large increments of generation (600 MW and greater), virtually instantaneously, from the transmission grid. *Id.* Generation dropping is severe duty that imparts wear and tear on equipment, which will incrementally decrease the life of and increase the maintenance required by the unit. *Id.* In addition to these costs, decreased unit life and increased maintenance reduce revenues during replacement or overhaul of the equipment. *Id.* BPA estimated the cost of the generation dropping RAS based on consultations with manufacturers and designers, and lost revenue from increased downtime. *Id.* Because these costs are incurred to promote transmission system reliability, these costs will be assigned to TBL.

Decision

BPA will assess TBL an annual inter-business line charge for generation dropping provided by PBL.

Issue 9

Whether BPA should assess TBL an annual inter-business line charge for station service provided by PBL.

Parties' Positions

No party raised this issue in an initial brief or brief on exceptions.

BPA's Position

BPA proposed to assess TBL an annual inter-business line charge for Station Service provided by PBL. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 87-88. *See also* DeClerck *et al.*, WP-02-E-BPA-26, at 18-19.

Evaluation of Positions

Station service is real power taken directly off the BPA power system for use by TBL at substations, Celilo, and the Ross Complex. DeClerck *et al.*, WP-02-E-BPA-26, at 18. The proposed inter-business line charge for station service does not include station service that is being purchased by the TBL from any other utility. *Id.* There are very few locations on the BPA system where station service is metered, so BPA developed a methodology to estimate this usage. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 88. Because station service power is used to operate the transmission system, BPA will assess TBL an annual inter-business line charge for station service provided by PBL based upon this methodology.

Decision

BPA will assess TBL an annual inter-business line charge for station service provided by PBL.

9.0 TRANSMISSION FOR NON-FEDERAL POWER

9.1 Introduction

BPA announced that it would address all GTA and GTA replacement issues in the power rate case, including determining the allocation of the costs to transmit the non-Federal power purchases of GTA customers over third-party transmission systems, and allocation of costs for delivering the Federal power purchases for such customers. 64 Fed. Reg. 44,318, 44,323 (1999). The treatment of GTA costs, whether for Federal or non-Federal power deliveries, is an issue that involves an equitable balancing of a number of historical, economic, and other factors. BPA built the Federal transmission system to provide regional transmission facilities to integrate Federal and non-Federal power, and to interconnect with other utility systems to transmit such power to existing and potential regional and interregional markets. *See* Bonneville Project Act, 16 U.S.C. §832a(b); and Transmission System Act, 16 U.S.C. §838b. These transmission services were provided on a rolled-in, average cost basis. The FCRTS was not extended to all of BPA's customers, however. BPA did not construct transmission facilities to some preference and DSI customers when it was less expensive to acquire GTA service over existing non-Federal transmission facilities. This decision resulted in lower overall network transmission rates that benefited all of BPA's customers.

BPA proposed that its historical GTA customers should be afforded the same opportunity as its other customers to acquire access to competitive bulk power markets and make non-Federal power purchases. Due to the unique history surrounding the provision of transmission service to BPA's historical GTA customers, BPA proposed to pay up to $6.5 million annually for the acquisition of network equivalent non-Federal transmission service for their non-Federal power purchases and roll such costs into the network. The proposal was limited to arrangements that transfer non-Federal power *from* BPA's transmission system over a third-party's system and *to* BPA's historical GTA customers. BPA believes that this proposal provides an equitable solution to a complex historical problem, and promotes competition in wholesale power markets, avoids pancaked rates, and promotes open access.

Issues relating to GTAs and GTA replacement costs for Federal power deliveries are discussed in section 8.3. This section analyzes the record evidence and addresses issues regarding the treatment of third-party transmission costs for non-Federal power as raised by the parties in their briefs.

9.2 Payment of Non-Federal Transmission Cost for GTA Customers' Non-Federal Power Purchases

Summary Issue

Whether BPA should pay up to $6.5 million per year for transmission over third-party systems to deliver non-Federal power to customers historically served by GTAs, and roll such costs into the network cost.

Summary of Parties' Positions

The Idaho Consumer-Owned Utilities Association, Inc. (ICUA), NRU, PNGC, and PPC supported BPA's proposal. ICUA stated that the proposal was an appropriate means of providing Idaho customers and the regional electric utility community the opportunity to resolve transmission pricing and operations issues until a Regional Transmission Organization (RTO) is established. Gendron, WP-02-E-ID-01, at 2. NRU maintained that the BPA proposal promotes a level playing field for wholesale power purchasers, promotes competition in bulk power markets, and advances the national policy to eliminate pancaked rates. Saven, WP-02-E-NI-03, at 8. PNGC claimed that the BPA proposal allows customers served over GTAs to access Federal and non-Federal power suppliers equally, and mitigates adverse transmission rate impacts and uncertainty associated with pancaked rates. Holt and Scott, WP-02-E-PN-01, at 2-5. The PPC supported the BPA proposal so long as costs were limited to $6.5 million a year to acquire network equivalent transmission. Hansen and O'Meara, WP-02-E-PP-08, at 1. WPAG generally supported BPA's GTA proposals. Oral Tr. 26.

CRITFC, Confederated Tribes and Bands of Yakama Nation (Yakama), and UCUT Tribes objected to BPA's proposal to the extent such offer was not also available to new preference customers. Sheets, WP-02-E-CR/YA-01, at 6; CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 48; UCUT Brief, WP-02-B-UC-01, at 10. The Joint DSIs opposed BPA's proposal, and claimed that BPA is not obligated by statute or common practice to pay for the transmission costs to deliver non-Federal power to some BPA customers. Schoenbeck and Bliven, WP-02-E-DS/AL/VN-06, at 22-27. The IOUs and Enron opposed BPA's proposal, and argued that the proposal is discriminatory and counter to FERC policy. The IOUs and Enron also asserted that the issue of pancaking should be addressed in RTO discussions. Brattebo *et al.*, WP-02-E-AC/GE/IP/MP/PL/PS/EN-05, at 7-10; Brattebo *et al.*, WP-02-E-AC/GE/MP/PL/PS/EN-11, at 4; IOU/Enron Brief, WP-02-B-AC/GE/IP/MP/PL/PS/EN-01, at 65-72. The IOUs and Enron concluded that withdrawal of the proposal would not result in GTA customers suffering economic harm, as it is unlikely that they will purchase much non-Federal power. Brattebo *et al.*, WP-02-E-AC/GE/MP/PL/PS/EN-11, at 6. The Public Generating Pool (PGP) argued that the issue of how costs should be allocated should be decided in the transmission rate proceeding; PGP opposed recovering the cost from network rates. Knitter and Peters, WP-02-E-PG-01, at 2; Knitter and Peters, WP-02-E-PG-02, at 1-2; PGP Brief, WP-02-B-PG-01, at 3.

Summary of BPA's Position

BPA proposed to pay up to $6.5 million annually for network equivalent non-Federal transmission service *from* BPA's network to deliver non-Federal power *to* customers historically served by GTAs. Metcalf and Furst, WP-02-E-BPA-35 at 1-3. BPA argued that its proposal would promote competition in bulk power markets and avoid introducing pancaked rates. *Id.* at 2-3. The lesser of $6.5 million or the forecast of the cost of network equivalent non-Federal transmission would be included in BPA's network cost. *Id.* at 3.

Summary Evaluation of Positions

BPA would roll the lesser of $6.5 million or the forecast of the cost of network equivalent non-Federal transmission into its network cost. Metcalf and Furst, WP-02-E-BPA-35, at 3. If BPA's forecast cost exceeded the cap, then BPA would calculate for each GTA customer a preliminary load percentage that would limit BPA's costs to $6.5 million per year. *Id.* at 6. BPA also proposed to include losses over the non-Federal transmission systems BPA paid for in the calculation of BPA's network loss factors. *Id.* at 7. Finally, BPA proposed that where both Federal and non-Federal power could be delivered at both GTA or BPA points of delivery, a *pro rata* share of the Federal and non-Federal power would be delivered over each path. PBL would pay the cost for delivering Federal power over the non-Federal point, and TBL would pay the cost for delivering non-Federal power over the same point consistent with the proposal described herein. *Id.* at 7-8. No parties raised any issue in their briefs on the allocation methodology if the cap is exceeded, the allocation methodology for GTA customers with both Federal and non-Federal points of delivery (PODs), or the treatment of losses. Accordingly, consistent with BPA's Procedures, where no issue is raised then the parties shall be deemed to take no position on these issues. Moreover, arguments are deemed to be waived. *Procedures*, §1010.13(c).

The parties' briefs raised several legal, factual, and policy issues to be resolved by the Administrator. Evaluations of the parties' and BPA's positions on these contested issues are presented below.

Sub-Issue 1

Whether BPA should decide in the power rate proceeding whether to pay up to $6.5 million per year for transmission over third-party systems to deliver non-Federal power to GTA customers.

PGP objected to the Administrator making a decision in the power rate case on BPA's proposal to pay for third-party transmission service to deliver non-Federal power to GTA customers. PGP argued that the decision should be made in the transmission rate case. Knitter and Peters, WP-02-E-PG-01, at 2; Knitter and Peters, WP-02-E-PG-02, at 2; PGP Brief, WP-02-B-01, at 2. ICUA, NRU, and PNGC maintained that they needed a decision regarding GTA or GTA equivalent service for deliveries of both Federal and non-Federal power made in the power rate case in order to make informed choices on their power supply decisions during the Subscription process. Gendron, WP-02-E-ID-01, at 3; Saven, WP-02-E-NI-03, at 8; Holt and Scott, WP-02-E-PN-01, at 9-10. PNGC declared that without BPA's proposal, GTA customers would pay additional transmission costs up to 10 mills/kWh for delivery of non-Federal power purchases. They argued that these additional costs would make it uneconomic for them to participate in the competitive power markets. Holt and Scott, WP-02-E-PN-01, at 4. Thus, the decision on this issue is far more likely to affect a customer's choice of power supplier than decisions on other transmission issues that will be made in the transmission rate case. The IOUs and Enron claimed BPA's proposal was improper, and lessening or eliminating pancaked rates would best be addressed through an RTO process. Brattebo *et al.*, WP-02-E-AC/GE/IP/MP/PL/PS/EN-05, at 10; Brattebo *et al.*, WP-02-E-AC/GE/MP/PL/PS/EN-11, at 4; IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 71.

NRU asserted that deferring the decision and waiting for an RTO was a chimera, as BPA's participation in an RTO is voluntary, and an RTO is not likely to provide relief for the relevant time frame. Saven, WP-02-E-NI-05, at 37.

BPA committed to address all issues on GTA-related costs, including GTA replacement costs, in the power rate case. Burns and Elizalde, WP-02-E-BPA-08, at 19-20; Cherry and Metcalf, WP-02-E-BPA-10, at 7. *See also* 64 Fed. Reg. 44318, 44323 (1999), providing that the allocation for non-Federal transmission costs for deliveries of Federal and non-Federal power to GTA customers would be decided in the power rate case. BPA included all GTA proposals in the power rate case because their resolution affects the level of the power revenue requirement. Burns and Elizalde, WP-02-E-BPA-08, at 19. BPA acknowledged that the GTA customers would be able to make more informed power purchase decisions by knowing BPA's decisions on the GTA issues for Federal and non-Federal power deliveries. Burns and Elizalde, WP-02-E-BPA-08, at 19-20; Cherry and Metcalf, WP-02-E-BPA-10, at 7.

PGP asserted that BPA "commingled" power and transmission decisions directly, and such action is contrary to FERC policy. PGP Ex. Brief, WP-02-R-PG-01, at 9. BPA does not understand PGP's assertion that power and transmission issues have been "commingled." GTA costs for Federal power deliveries were proposed to be included in the power rates. Cherry and Metcalf, WP-02-E-BPA-10, at 7. *See* discussion in section 8.3, *supra*, regarding GTA expenses for Federal power deliveries. The costs for non-Federal power deliveries were proposed to be included in transmission rates. *Id.* Non-Federal transmission costs for non-Federal power deliveries are addressed in this ROD chapter. The decisions made in the power rate case will not be revisited in the subsequent transmission rates and terms and conditions cases. *Id.* at 8. Tr. 316-318. PGP also claims that deciding these issues in the power rate case is a direct violation of Order 888. PGP Ex. Brief, WP-02-R-PG-01, at 9. PGP, however, fails to identify any particular provision of Order 888 that is violated.

The treatment of GTA costs for delivery of Federal or non-Federal power is an issue that involves an equitable balancing of a number of historical, economic, and other factors. It is appropriate that BPA evaluate these issues in one forum, rather than two. BPA, however, has not commingled the decisions.

<u>Decision 1</u>

BPA is addressing all issues concerning GTA and GTA replacement costs for Federal and non-Federal power deliveries for GTA customers in the 2002 power rate case. Accordingly, in this ROD BPA decides whether to pay for a portion of the non-Federal transmission costs for delivery of non-Federal power to GTA customers.

<u>Sub-Issue 2</u>

Whether the costs for third-party transmission to deliver non-Federal power to GTA customers should be rolled into network cost, and whether such treatment is contrary to FERC policy.

ICUA, PNGC, and NRU support rolling the third-party transmission costs for non-Federal power deliveries into BPA's network cost. Gendron, WP-02-E-ID-01, at 1; Holt and Scott, WP-02-E-PN-01, at 2; Saven, WP-02-E-NI-03, at 8, 10. ICUA stated that the FCRTS was not extended into Idaho for a variety of economic and political reasons. As a result, BPA established GTA service to Idaho customers in lieu of constructing network facilities. ICUA maintains that GTAs are the functional equivalent of BPA's network service. Gendron, WP-02-E-ID-01, at 1-2; ICUA Brief, WP-02-B-ID-01, at 1. ICUA opposes directly assigning the costs to GTA customers. ICUA Brief, WP-02-B-ID-02, at 8. PNGC declared that BPA's decision to acquire transmission through GTAs rather than constructing additional Federal transmission facilities was prudent. PNGC agreed with BPA that this decision resulted in lower overall network transmission rates that benefited all BPA customers, especially wheeling or predominantly wheeling customers. Holt and Scott, WP-02-E-PN-01, 2-3; PNGC Brief, WP-02-B-PN-01, at 19-20.

The IOUs and Enron claimed that Northwest utilities used a "one-system planning" model to avoid building duplicative facilities. They admitted that this practice benefited the region's power and wheeling customers, but argued that such benefit is not a justification for rolling third-party transmission costs into BPA's network costs. Brattebo *et al.*, WP-02-E-AC/GE/IP/MP/PL/PS/EN-05, at 8-9. The IOUs and Enron contended that BPA's network rates were not lower because of GTA service. They maintained that GTA costs were historically assigned to the Fringe segment, and were charged to BPA's power customers. The IOUs and Enron asserted that the cost of duplicative facilities that might have been constructed would also have been charged to BPA's Fringe segment and borne by power customers. Brattebo *et al.*, WP-02-E-AC/GE/IP/MP/PL/PS/EN-11, at 4.

PGP argued that certain conditions should be met before the third-party transmission costs are recovered through network transmission rates. Knitter and Peters, WP-02-E-PG-01, at 2. These conditions include a demonstration that BPA applied for and acquired the third-party transmission, and that the non-Federal transmission capacity is available to any transmission customer, except Federal power. Knitter and Peters, WP-02-E-PG-01, at 3. PNGC countered that PGP's proposed conditions resulted in a higher test for inclusion of GTA costs in transmission rates than for any other type of forecasted transmission expense. Accordingly, PNGC argued, the PGP's proposed conditions should be rejected. Scott and Scher, WP-02-E-PN-17, at 15.

BPA's proposal to include non-Federal transmission cost in the network is due to the unique history surrounding the provision of transmission service to BPA's historical GTA customers. Scott and Scher, WP-02-E-PN-02, Attachment at 2. BPA built the Federal transmission system to deliver Federal power to BPA's preference and DSI customers and to other regional and inter-regional markets, and to provide wheeling service for non-Federal power. BPA did not construct transmission facilities to some preference and DSI customers when it was less expensive to acquire GTA service over existing non-Federal transmission facilities. Metcalf and Furst, WP-02-E-BPA-35, at 2. When BPA's non-GTA customers constructed resources or made non-Federal power purchases or sales, BPA provided transmission service to them on a rolled-in average basis. Scott and Scher, WP-02-E-PN-02, Attachment at 2. The GTA arrangements benefited all BPA power and transmission customers, particularly wheeling customers. BPA spent less money on acquiring transmission service over the GTAs than it would otherwise have spent to construct transmission facilities. While the GTA costs were not included in BPA's network cost, the GTA customers' loads were allocated network costs. Metcalf and Furst, WP-02-E-BPA-35, at 2.

As a policy matter, BPA agrees that GTA customers should be afforded the same ability as BPA's other customers to acquire non-Federal power from BPA's transmission system over network-equivalent facilities without paying pancaked transmission rates. Scott and Scher, WP-02-E-PN-02, Attachment at 3. BPA capped the annual cost at $6.5 million as a reasonable balance between mitigating the effect of pancaked rates on GTA customers and protecting the network transmission rates from large cost increases. Metcalf and Furst, WP-02-E-BPA-35, at 5. BPA will forecast costs in the transmission rate case based on the best information available at the time, and the lesser of the forecasted amount or $6.5 million will be included in the network cost. *Id.* at 3. Only costs for which BPA could get billing determinants would be put into the network. Tr. 362.

The IOUs and Enron claimed that BPA's proposal to include the costs of third-party transmission service in its transmission network revenue requirement runs counter to FERC policy. Brattebo *et al.*, WP-02-E-AC/GE/IP/MP/PL/PS/EN-05 at 8. The IOUs, Enron, and the DSIs rely on *Niagara Mohawk Power Corp.(Niagara)*, 82 FERC ¶ 63,018 (1998) and *New England Power Co. (New England)*, 65 FERC ¶ 61,153 (1993) to support their argument that FERC policy would not allow past avoided costs to justify BPA's proposal to roll the costs into BPA's network rates. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 69; DSI Brief, WP-02-B-DS-01, at 83. These parties agree, however, that the FERC policy allows the transmission costs of facilities used as part of the transmission provider's integrated network to be included in the network transmission revenue requirement. *Id*. The DSIs also contend that such costs may be included in the utility's rates if it uses the facilities on a day-to-day basis. DSI Brief, WP-02-B-DS-01, at 83.

ICUA, PNGC, and NRU argue that BPA's proposal is consistent with FERC policy. ICUA maintains that BPA must provide the same level of service to users of its network as it provides for deliveries of Federal power. ICUA Brief, WP-02-B-ID-02, at 6. ICUA contends that the policies of Orders 888 and 889 argue forcefully for providing broad and nondiscriminatory access to bulk power markets. *Id.* at 7. PNGC claims that FERC's policy goals to hold the transmitting utility's native load customers harmless, and to charge third-party transmission customers the lowest reasonable cost-based rates, would be furthered by BPA's proposal. PNGC Brief, WP-02-B-PN-02 at 19. The proposal also would promote FERC's ultimate goal, articulated in the Regional Transmission Organization Notice of Proposed Rulemaking, of promoting fully competitive bulk power markets by providing an opportunity for historical GTA customers to avoid pancaked rates. *Id.* at 20. NRU acknowledges that FERC policies are many, and a comprehensive view recognizes that promoting wide and nondiscriminatory access to bulk power markets is among the most significant of FERC's concerns. Saven, WP-02-E-NI-05, at 36; NRU Brief, WP-02-B-NI-02, at 17. NRU contends that FERC policy does not prevent rolling in third-party costs if the facilities are effectively a part of the utility's integrated transmission system. Finally, NRU argues that elimination of pancaked rates is encouraged by Order 2000. NRU Brief, WP-02-B-NI-02, at 18; Oral Tr. 191. PPC notes that the IOU, Enron, and DSI objections to BPA's proposal are based on FERC policy and precedent applicable to IOUs. PPC is unclear that this policy is applicable to BPA. PPC Brief, WP-02-B-PP-01, at 42.

BPA disagrees with the IOU, Enron, and DSI position that BPA's proposal is contrary to FERC policy. BPA's proposal meets the FERC test for inclusion of these costs in its transmission rates. TBL, historical GTA, or other open access transmission tariff eligible customers would acquire open access service over the non-Federal transmission system to deliver non-Federal power to historical GTA customers. That transmission would be available to be used on a day-to-day basis, in combination with BPA-owned facilities, to provide flexible open access service to such customers. BPA's proposal also supports FERC's policies to eliminate pancaked rates, and to promote competition in bulk power markets, in the context of the historical GTA service. Metcalf and Furst, WP-02-E-BPA-35, at 2-3. The IOUs/Enron claim that BPA is not proposing to eliminate pancaked rates, nor is BPA's proposal an incremental step in eliminating pancaked rates. IOUs/Enron Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 54 (IPC and MPC do not join the brief on this issue). BPA does not disagree. BPA clarified that it supports FERC's objectives under Order 2000 to establish RTOs which purpose, among others, is to eliminate pancaked rates. BPA, however, is neither proposing to eliminate pancaked rates nor rely on its proposal as an incremental step in eliminating pancaked rates. Rather, BPA's proposal is designed to avoid *introducing* pancaked rates to customers who have not faced them in the past. Tr. 380-383.

The IOUs/Enron also assert that the *Niagara* and *New England* opinions disallow the inclusion of third-party costs to deliver any power to retail load off the utility's system. IOU/Enron Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 53 (IPC and MPC do not join the brief on this issue). BPA disagrees that *New England* and *Niagara* opinions are concerned with *any* power deliveries to a utility's remote loads. BPA's proposal differs from the facts underlying FERC's policies that prohibit the inclusion of third-party transmission costs in a utility's transmission rates. Tr. 369. In the *New England* and *Niagara* opinions applicable to public utilities under the FPA, FERC did not allow the utilities to include third-party transmission costs to import remote generation *purchased by* the utility to serve its power customers, or that it used to deliver power *it owned or purchased* to serve its remote customers or retail load. *See New England*, 62 FERC ¶ 61,294, 62,908 (1993); and *Niagara*, 82 FERC ¶ 63,018, 65,136-7 (1998). BPA continues to treat as Federal power costs the costs of third-party transmission that is acquired to deliver power from Federal projects or power that BPA purchases to serve the full requirements needs of its remote customers. Tr. 369-370. *See also* section 8.3, *supra*. BPA clarified that this is not the purpose of the instant proposal. BPA would pay for the third-party transmission costs to deliver non-Federal power purchased by the historical GTA customer, not power purchased by BPA. Tr. 370.

The IOUs/Enron claim that BPA's proposal violates FERC's policy that the costs of facilities used to provide a particular transmission service should not be charged twice to customers who may use that service. IOU/Enron Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 54 (IPC and MPC do not join the brief on this issue). The IOUs/Enron assert that BPA will pay for such transmission only on the request of BPA's historical GTA customers, but would not acquire or pay for transmission over the same facilities that is acquired by other transmission customers. *Id.* The IOUs/Enron misunderstand BPA's proposal. It is available for the network equivalent non-Federal transmission required for the delivery of non-Federal power to historical GTA customers. Metcalf and Furst, WP-02-E-BPA-35, at 3. The proposal is not limited to non-Federal transmission acquired only by GTA customers. The costs acquired by other transmission customers who access the same non-Federal transmission facilities from BPA's transmission system to deliver non-Federal power to historical GTA customers would also be eligible. Thus, there would be no double-charging under BPA's proposal.

Finally, PGP alleges that BPA's proposal violates FERC's Transmission Pricing Policy, because BPA fails to treat such costs as new construction or incremental costs; and such incremental costs have not been subjected to an "or" pricing or Direct Assignment test. PGP concludes that because BPA's proposal allegedly violates FERC's Transmission Pricing Policy, FERC will remand BPA's rates, and BPA's rates will not be sufficient to assure repayment of the Federal investment or meeting BPA's operating costs. PGP Ex. Brief, WP-02-R-PG-01, 8-12. PGP, however, fails to point to any record evidence that BPA's proposal contemplates any new construction or should be treated as new construction costs. BPA does not agree that the Transmission Pricing Policy relating to incremental costs is applicable to this transmission expense. BPA does not propose to construct any new transmission facilities. BPA proposes to pay only annual costs, not any new capital investment. Metcalf and Furst, WP-02-E-BPA-35, at 3. Because no new construction is contemplated, the "or" pricing test would not trigger. Furthermore, BPA's proposal is for the cost of transmission of non-Federal power over only *network-equivalent* transmission facilities. *Id.* Thus, even if the Transmission Pricing Policy were applicable, a Direct Assignment test is not required.

Decision 2

Rolling into the network the costs of third-party transmission service to deliver non-Federal power to historical GTA customers is appropriate and not contrary to FERC policy. It is an equitable solution to a complex historical problem, and would promote competition in wholesale power markets, avoid pancaked rates, and promote open access.

Sub-Issue 3

Whether BPA's proposal is unduly discriminatory or preferential.

The IOUs state that section 212(i) of the FPA requires the rates for certain BPA transmission service not be unjust, unreasonable, or unduly discriminatory or preferential. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 66; *see also* DSI Ex. Brief, WP-02-R-DS-01, at 22-23. The IOUs, Enron, Joint DSIs, and PGP maintain that limiting the BPA proposal to BPA's historical GTA customers is unduly discriminatory or preferential. Brattebo *et al.*, WP-02-E-AC/GE/IP/MP/PL/PS/EN-05, at 7; IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 66; IOU/Enron Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 52 (IPC and MPC do not join the brief on this issue); Schoenbeck and Bliven, WP-02-E-DS/AL/VN-06, at 25-26; DSI Ex. Brief, WP-02-R-DS-01, at 23; PGP Brief, WP-02-B-PG-02, at 2.

ICUA claims that FERC's discrimination analysis examines whether the service a transmission owner provides to third-party users is similar to the service it provides itself. ICUA Brief, WP-02-B-ID-02, at 6. ICUA concludes that BPA, through its reciprocity tariff and rates, must therefore provide the same level of service to other users of its network as it provides for deliveries of Federal power. *Id.* NRU claims that BPA's proposal is not unduly discriminatory or preferential, because BPA proposed to treat similarly situated customers, the entire class of customers served by GTAs, in the same way. Saven, WP-02-E-NI-05, at 34; NRU Brief, WP-02-B-NI-02, at 16.

In support of their argument that BPA's proposal is unduly discriminatory or preferential, the IOUs rely on the "undue" discrimination analysis articulated in *New England Power Pool (NEPOOL)*, 67 FERC ¶ 61,042 (1994). The IOUs claim that FERC's undue discrimination analysis examines whether factual differences justify different rates for similarly situated customers. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 66. In *NEPOOL,* FERC expanded its undue discrimination analysis to apply it to the rates and transmission services of the utility's own use of the system. *NEPOOL*, 67 FERC ¶ 61,042, at 61,132. The NEPOOL participants proposed to continue to discount transmission rates to existing generation jointly owned by the participants and charge full transmission rates to any new generation using the transmission system. FERC had previously found that the reduction in cost for one group of customers (the pool coordination group) was in the public interest and outweighed the reduction in wholesale competition. In *NEPOOL* it reevaluated that decision by looking at whether the proposal was so anti-competitive as to be unjust and unreasonable. *Id.* at 61,132-61,133.

In their brief on exceptions, the IOUs/Enron argued that FERC's undue discrimination analysis disallows *any* discrimination among similarly situated customers. IOU/Enron, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 52-53. BPA disagrees. FERC has long held that discrimination is unlawful under the FPA only when undue, and undue discrimination means "substantially different treatment to 'similarly situated' entities without good reasons." *ANR Pipeline Co. v. Transcontinental Gas Pipe Line Corp.*, 91 FERC ¶ 61,066, at 18 (2000) (citing *Pacific Gas & Electric Co.*, 38 FERC 61,242 (1987)). *See also The Electric and Water Plant Board of the City of Frankfort, Ky. v. Kentucky Utilities Co.*, 12 FERC ¶ 61,004 at 61,008 (1980) (where FERC found that discrimination that is undue or unreasonable is prohibited by the FPA, and discrimination which is anti-competitive in effect is presumptively undue).

These standards are not dissimilar to those articulated in *NEPOOL*. Here, BPA's proposal is a reasonable proposal that is available to historical GTA customers due to the unique history of providing transmission service to them. Eligibility is limited to the transmission of non-Federal power that is delivered *from* BPA's transmission system over a third party's system *to* historical GTA customers. No other BPA transmission customers are similarly situated to GTA customers. Moreover, the proposal is capped at the lower of $6.5 million or the forecast of expected non-Federal power acquisitions by these customers. BPA settled on this cap as a reasonable balance to mitigate the effect on GTA customers of avoiding introducing pancaked rates and to protect network rates from large cost increases. Metcalf and Furst, WP-02-E-BPA-35, at 5. The proposal is in the public interest, as it promotes, rather than prevents, access to competitive bulk power markets, and it avoids introducing additional pancaked rates for non-Federal power deliveries *from* BPA's system *to* such customers' loads. *Id.* at 2-3. Finally, the proposal is not so anti-competitive as to be unjust and unreasonable. Nor does the proposal provide a significant advantage to historical GTA customers. The proposal levels the playing field to place historical

GTA customers in a position similar to BPA's other transmission customers. GTA customers, however, continue to be responsible, like all other BPA transmission customers, for transmission costs to deliver non-Federal power *to* BPA's transmission system. The proposal is expected to cause an increase to the transmission rates of less than 2 percent. Holt and Scott, WP-02-E-PN-02, Attachment at 3.

PNGC declared that without BPA's proposal, GTA customers would be significantly disadvantaged, as they would pay additional transmission costs up to 10 mills/kWh for delivery of non-Federal power purchases over third-party systems. They argued that these additional costs would make it uneconomic for them to participate in the competitive power markets. Holt and Scott, WP-02-E-PN-01, at 4-5. PNGC also pointed out that the inclusion of third-party wheeling costs for non-Federal power purchases allowed customers access to other power suppliers and eroded BPA's market power. Scott and Scher, WP-02-E-PN-07, at 11. Without BPA's proposal, the GTA customer's only economic power supplier other than BPA is the local IOU transmission provider. *Id*. at 12. PNGC argued that the IOU and Enron objection was merely an attempt to protect their own market power dominance over the captive GTA customers. *Id*. BPA's proposal is not unduly discriminatory and is consistent with the comparability standard, because it allows GTA customers to pay the same transmission costs regardless of whether they purchase power from the PBL or non-Federal power suppliers. All potential non-Federal power suppliers, including Enron and the IOUs, are eligible for this treatment.

The IOUs/Enron, CRITFC, Yakama, and UCUT also argue that BPA's proposal violates section 7(a)(2)(C) of the Northwest Power Act, which requires Federal transmission costs to be equitably allocated between Federal and non-Federal power using the transmission system. In addition, CRITFC, Yakama, and UCUT argue that the proposal is not consistent with section 10 of the Transmission System Act, containing similar provisions. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 66; IOU/Enron Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01; CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 50; UCUT Brief, WP-02-B-UC-01, at 12-15. The IOUs and Enron complain that it is inequitable to allocate the costs incurred for a group of customers to all users of the network. IOU/Enron Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 51-52. They also imply that the equitable allocation standard was intended to apply to customers traditionally *purchasing* Federal power. *Id.* at note 160. Section 7(a)(2)(C) clearly provides that transmission rates shall equitably allocate the costs of the Federal transmission system *between Federal and non-Federal power using the transmission system*. 16 U.S.C. §839e(a)(2(C). As explained previously, the costs associated with the proposal are to deliver non-Federal power to historical GTA customers. Costs for GTA deliveries of Federal power are allocated to power rates as described in section 8.3, *supra.* BPA balanced competing issues and found that the public interest to provide access to and promote competitive bulk power markets and avoid the introduction of additional pancaked rates outweighed a small increase to network rates. Metcalf and Furst, WP-02-E-BPA-35, at 5. It is not uncommon for BPA to be faced with deciding whether costs incurred for service to particular utilities should be rolled into the network. A network rate increase is often the result of the aggregate of multiple projects and policies that benefit individual utilities. It would be inequitable for BPA to single out one of these projects or policies without considering the totality of the circumstances. Thus, balancing the competing interests results in an equitable, or just and reasonable solution. CRITFC, Yakama, and UCUT contend that BPA's proposal is also a disincentive for the formation of new preference customers. CRITFC/Yakama Brief, WP-02-B-CR/YA-01; UCUT Brief, WP-02-B-UC-01, at 51-52. Preference status, however, grants public bodies and cooperatives priority access to Federal power, not to non-Federal power. 16 U.S.C. §832c(a).

The DSIs rely on section 205 of the FPA, which requires that a public utility's rates shall be just and reasonable, to assert that if BPA seeks reciprocity for its open access tariff its rates must also be just and reasonable. DSI Brief, WP-02-B-DS-01, at 82. The DSIs' reliance on section 205 is misplaced, as that section of the FPA applies to *public utilities* and is not applicable to BPA. 16 U.S.C. §824(e). Even if it were, the foregoing discussion demonstrates that the proposal is a just and reasonable resolution of the complex historical issues involved. In their brief on exceptions, the DSIs also claim that BPA's proposal is arbitrary, capricious, and contrary to law. DSI Ex. Brief, WP-02-R-DS-02. For the reasons described in the foregoing paragraphs and subsections, BPA disagrees that its proposal is arbitrary, capricious and contrary to law. *See* section 1.4, *supra*, for further discussion of the standard governing judicial review of BPA's rates. *See also* 16 U.S.C. §839f(e)(2).

Decision 3

BPA's proposal is not unduly discriminatory or preferential. BPA's proposal is in the public interest, as it promotes access to competitive bulk power markets, avoids the creation of additional pancaked rates, and is not anti-competitive. It takes into account historical equities, and results in an equitable or just and reasonable solution.

Sub-Issue 4

Whether BPA's proposal should be modified to allow customers currently served by the South Idaho Exchange Agreement to participate.

ICUA, NRU, and PNGC argued that BPA's proposal should be extended to customers currently served by the South Idaho Exchange Agreement between BPA and PacifiCorp. NRU claimed that the South Idaho Exchange Agreement serves a similar function as the GTAs, and urged BPA to provide the same treatment for utilities served from the South Idaho Exchange mechanism as BPA intended to provide to GTA customers. Saven, WP-02-E-NI-03, at 10-11; NRU Brief, WP-02-B-NI-02, at 16. ICUA recommended that BPA include deliveries of non-Federal power either through the South Idaho Exchange or an equivalent replacement. ICUA also contended that BPA should eliminate the requirement that non-Federal power deliveries come from the BPA network. Gendron, WP-02-E-ID-01, at 3. PNGC wanted BPA to extend its proposal to the South Idaho Exchange, and supported elimination of the requirement that non-Federal power use the BPA network for the affected South Idaho utilities. Holt and Scott, WP-02-E-PN-01, at 6-8; PNGC Brief, WP-02-B-PN-01, at 20-21. In contrast, the IOUs opposed any expansion of BPA's proposal. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 70. In particular, PacifiCorp argued that the South Idaho Exchange Agreement is limited to the exchange of Federal power and PacifiCorp power, and any amendment to the Agreement would require FERC approval.

PacifiCorp asserts, without citing to any testimony, that the affected South Idaho utilities may require transmission service over Idaho Power's facilities, as well as PacifiCorp's facilities. *Id.*

The proposal is available for the delivery of non-Federal power that uses BPA's network to historical GTA customers with existing service territories. Payment under the proposal would be limited to the cost of non-Federal transmission service from BPA's network *over* the intervening non-Federal transmission system *to* such customers, up to the limits of the proposal. Metcalf and Furst, WP-02-E-BPA-35, at 4. BPA maintained that no modification to its proposal was necessary to allow customers currently served through the South Idaho Exchange to participate. Metcalf and Furst, WP-02-E-BPA-57, at 2. BPA explained that transmission service could be provided to the affected South Idaho utilities if non-Federal power deliveries used a South Idaho Exchange mechanism or the redispatch provisions of a non-Federal utility's open access tariffs. *Id.* Redispatch arrangements, including arrangements like the South Idaho Exchange, are consistent with FERC policy if they are made by the utility's transmission function. *See Utah Associated Municipal Power Systems (UAMPS) v. PacifiCorp*, 83 FERC ¶ 61,337 (1998) (where FERC concluded that all redispatch arrangements were the responsibility of the transmission function). On rehearing, FERC clarified that where PacifiCorp's merchant function purchased power at receipt points on PacifiCorp's transmission system, and simultaneously sold the same amount of power to the party at other delivery points on PacifiCorp's transmission system, such redispatch arrangement effected transmission service. *See UAMPS v. PacifiCorp*, 87 FERC ¶ 61,044 (1999). FERC reiterated that this type of arrangement is the responsibility of the transmission function. *See also, Arizona Public Service Co. (Arizona) v. Idaho Power Co. (IPC)*, 87 FERC ¶ 61,303 (1999), where FERC directed IPC to consider whether redispatch could serve to meet Arizona's transmission request; and IPC's Compliance Filing, July 19, 1999, concluding that there may be some capacity available in months of the year other than July for short-term or monthly firm service.

BPA rejected the ICUA and PNGC proposal that would eliminate the requirement that non-Federal power be delivered from the BPA network to the third-party transmission system for customers currently served by the South Idaho Exchange. Metcalf and Furst, WP-02-E-BPA-57, at 2. BPA explained that the customer would be responsible for costs to deliver the non-Federal power to BPA's system at Goshen, and under the proposal, BPA would pay for the non-Federal transmission from Goshen over the intervening non-Federal transmission system to the customer's points of delivery, subject to the conditions of its proposal. *Id.*

Decision 4

It is not necessary to modify or eliminate any provisions in BPA's proposal to allow customers currently served by the South Idaho Exchange to participate. These customers would be eligible, under the proposal, for arrangements that deliver non-Federal power from BPA's system over a third party's system to the customer.

Sub-Issue 5

Whether the BPA proposal should be adopted through FY 2006.

NRU urged BPA to pay up to $6.5 million for non-Federal transmission to deliver non-Federal power to GTA customers until an RTO is operational that completely addresses pancaking issues. Saven, WP-02-E-NI-03, at 9. NRU recommended that, if the pancaking problem persists beyond September 30, 2006, then BPA should extend the proposal until the pancaking issue is resolved. *Id.*; NRU Brief, WP-02-B-NI-01, at 15. PNGC supported extending BPA's proposal for the duration of the five-year power rate period. Holt and Scott, WP-02-E-PN-01, at 5. PGP disagreed with both the PNGC and NRU views that payments of up to $6.5 million for non-Federal power deliveries to GTA customers should be extended beyond the transmission rate period ending 2003. Knitter and Peters, WP-02-E-PG-02, at 2. PGP argued that the Administrator should not decide in the power rate case that any particular treatment of transmission rates should persist until resolution of the pancaking issue is achieved. *Id.* at 3. The IOUs and Enron expressed concern that BPA's proposal is not a harmless means of filling the gap until an RTO is formed. Brattebo *et al.*, WP-02-E-AC/GE/IP/MP/PL/PS/EN-11, at 5. The IOUs and Enron argued that if an RTO is formed that does not completely address the pancaking issue, then the BPA proposal could continue indefinitely. *Id.*

BPA explained that an RTO that would include BPA's transmission facilities is expected to be formed and operational before September 30, 2003. BPA anticipates that pancaking issues will be addressed by the RTO. Metcalf and Furst, WP-02-E-BPA-35, at 4. BPA declared that if an RTO is not operational or does not completely address the pancaking problem, then BPA's proposal would be continued for the full five-year power rate period.

Decision 5

BPA's proposal will be effective until the earlier of the formation of an RTO that incorporates BPA's transmission facilities or through September 30, 2006.

Summary Decision

BPA will pay up to $6.5 million per year for transmission over third-party systems to deliver non-Federal power to customers historically served by GTAs or to utilities currently served by the South Idaho Exchange arrangement, and will roll such costs into the network. This proposal will be effective until the earlier of the formation of a regional RTO that incorporates BPA's transmission facilities or September 30, 2006. Eligibility is limited to arrangements that transfer power from BPA's system over a third-party's system to historical GTA customers or utilities currently served by the South Idaho Exchange arrangement.

10.0 WHOLESALE POWER RATE DESIGN

10.1 Introduction

BPA's 2002 rate proposal included 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, including deregulation and the unbundling of products and services. Therefore, BPA proposed several new products and services that are intended to meet the demands of a more competitive electric utility marketplace and to better serve the needs of BPA's regional customers. In doing so, BPA also revised its rate design to reflect cost causation more accurately and 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 suppliers.

The primary changes in BPA's power rate design are as follows:

- BPA revised the six seasonal periods used in BPA's 1996 rates to monthly periods for energy and demand, section 10.2.
- BPA continued to use market forecasts in developing the monthly Demand Charge in order to send accurate price signals to customers, section 10.4.
- The Load Shaping Charge has been eliminated and replaced by the Load Variance Charge. The primary cost drivers of the Load Variance Charge are the customer's right to place load growth on BPA and energy consumption variations due to factors such as weather, section 10.5.
- The Unauthorized Increase Charges (UAI Charges) were modified to more accurately reflect the potential costs to BPA caused by customers exceeding their contractual entitlement to take power, section 10.6
- The Excess Factoring Charge was added to compensate BPA for providing factoring service that is outside the factoring benchmarks, section 10.7.
- A SUMY Charge has been adopted to compensate BPA for the estimated cost of serving a multiyear Block which steps up over the years, section 10.9.
- A C&R Discount was added to encourage and support the development of conservation projects and renewable resources in the region, section 10.13.
- The TAC was added; 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, section 10.15.

The Subscription core products and the design of the rates applicable to them were developed consistent with certain key BPA business principles, including equitable comparability among purchasers, the common tables of rates, and the concept of effective rate. BPA's Subscription core products were 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. There are common tables of rates for Demand, HLH and LLH energy, and Load Variance, where applicable. The common tables of rates are associated with tables of billing factors showing the billing determinants appropriate to the specific products--Demand, Demand Adjuster where applicable, HLH and LLH energy, Load Variance, and Unauthorized Increase and Excess Factoring.

10.2 Monthly and Diurnal Differentiation of Energy Charges

BPA is using the same basic approach to establish energy rates for the FY 2002-2006 rate period that was used in the 1996 rate case. Rates are shaped to a forecast of market-based marginal costs for the rate period and then adjusted so that the revenue requirement is neither overcollected, nor undercollected. Keep *et al*., WP-02-E-BPA-17, at 13. As in BPA's current rates, rates for FY 2002-2006 are diurnally differentiated. *Id.* The primary change is that BPA is setting monthly energy rates for the 2002-2006 rate period. *Id.* This is a change from the 1996 rate case, which had six seasons for HLH and LLH energy rates. *Id.* BPA proposed monthly energy rates for three reasons. First, spot market electricity prices in the Northwest are showing significant month-to-month variation. *Id.* For example, over the last two years the average month-to-month variation in electricity prices for firm onpeak power at Mid-C has exceeded 20 percent. *Id.* Second, BPA's Marginal Cost Analysis Study, WP-02-FS-BPA-04, shows substantial monthly differentiation in predicted energy rates for the FY 2002-2006 rate period. *Id.* Third, because of reduced flexibility in operating the hydrosystem, BPA is more frequently forced to purchase in the market to meet requirements load. *Id.* Therefore, to reduce BPA's exposure to market risks in meeting its contractual commitments to meet requirements load, it is appropriate for BPA to set monthly energy rates for the FY 2002-2006 rate period. *Id.* Because no party raised the issue of monthly and diurnal differentiation of energy charges on brief, this issue is withdrawn in accordance with the *Procedures Governing Bonneville Power Administration Rate Hearings*, §1010.3, 51 Fed. Reg. 7611 (1986).

As stated in Keep *et al.*, WP-02-E-BPA-17, at 14, the 2002 HLH and LLH energy rates were established in a four-step procedure. First, BPA estimated its marginal costs for the FY 2002-2006 rate period. *See* Marginal Cost Analysis Study, WP-02-FS-BPA-04. BPA uses monthly energy rates from the Marginal Cost Analysis Study as inputs in the calculation of demand and load variance charges, and to shape the energy rates. Keep *et al.*, WP-02-E-BPA-17, at 14. Next, 2002-2006 demand and load variance revenues were calculated by multiplying the demand and load variance charges by estimated loads. *See* Loads and Resources Study, WP-02-FS-BPA-01. These revenues were subtracted from BPA's FY 2002-2006 revenue requirement. Keep *et al.*, WP-02-E-BPA-17, at 14. Finally, HLH and LLH energy rates were derived by adjusting the monthly and diurnal energy prices from the Marginal Cost Analysis Study to assure that only the revenue requirement is collected. *Id.* This is done because using forecasted market energy prices as rates would overcollect BPA's revenue requirement. *Id.* Monthly HLH and LLH energy rates from the Marginal Cost Analysis Study were reduced proportionately until estimated revenues from energy charges equaled the balance of BPA's revenue requirement. *Id.* Because no party raised the issue of how BPA established HLH and LLH energy prices on brief, this issue is withdrawn in accordance with the *Procedures.*

10.3 Rate Caps for Demand and Load Variance Charges

Issue

Whether BPA should remove or reduce caps on Demand and Load Variance Charges and adopt an alternative rate mitigation package to protect customers from excessive rate increases due to rate design changes.

Parties' Positions

The IOUs and PGE state that BPA ignored the rate mitigation proposal proffered by the HLFG. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 61; PGE Brief, WP-02-B-GE-01, at 12. In their brief on exceptions, the IOUs incorporate by reference their initial brief. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01. NRU opposes the HLFG's alternative rate mitigation proposal. NRU Brief, WP-02-B-NI-02, at 6.

WPAG argues that the proposed increase for the PF rate Demand Charge is out of line with the level of increase being proposed for other rate components. WPAG Brief, WP-02-B-WA-01, at 4. WPAG states that an increase of more than 150 percent to the Demand Charge is not justified in a rate proceeding where the average PF rate will be unchanged. *Id.* PNGC argues that increases in the Demand Charges are dramatic and draconian and are seemingly inconsistent with BPA's assertion of maintaining rates at PF-96 levels. PNGC Brief, WP-02-B-PN-01, at 24.

BPA's Position

BPA proposed caps on the Demand and Load Variance Charges and is offering a power product under the FPS rate schedule to mitigate inordinate rate impacts on irrigation loads. Burns and Elizalde, WP-02-E-BPA-08, at 18. BPA rebutted recommendations made by the HLFG to remove the caps. Burns and Elizalde, WP-02-E-BPA-37, at 11. The price caps as proposed balance the competing goals of rate stability and product pricing to reflect cost. *Id*.

Evaluation of Positions

The IOUs and PGE argue that BPA's rebuttal "ignored" an alternative $30 million rate mitigation package that would be explicit rather than hidden in rate design. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 61; PGE Brief, WP-02-B-GE-01, at 12. They make the supposition that none of BPA's workgroups looked at how BPA could achieve its rate design and rate impact mitigation goals to take into account BPA's Subscription policy goals. *Id*. They contend that this failure appears to be a function of BPA's "fragmented" rate development process. *Id*. They claim that adopting the HLFG recommendations will better effectuate both of the competing goals of sending appropriate market price signals and mitigating rate impacts. *Id*.

NRU supports BPA's proposed caps and argues that the HLFG mischaracterizes them as "mitigation." NRU Brief, WP-02-B-NI-02, at 7. NRU notes that the HLFG proposal starts by uncapping the Demand and Load Variance Charges and replacing both the caps and a $20 million mitigation proposal for selling surplus power to utilities with irrigation loads with an alternative mitigation program. *Id*. The alternative program would provide a total of $30 million for all impacted utilities over five years; would be front loaded; and would be phased out over the rate period. *Id*. NRU argues that the effects of this proposal would likely be exacerbated if the HLFG's proposals to model BPA rates after the volatility of the CalPX were adopted; it ignores the need for rate continuity and the significant adverse impacts that proposed changes in BPA's rate design will have on small full requirements utilities; it is inconsistent with the Subscription ROD that commits BPA to an irrigation mitigation program involving surplus sales over the entire rate period; and it is unsupported by any evidence other than the HLFG's heavy reliance on particular economic theories of ratemaking. *Id*.

The HLFG argued that both caps distort the market price signals and lead to economically inefficient solutions for society regarding electrical capacity usage. Koehler *et al*., WP-02-E-HL-01, at 9. In particular, the HLFG argued that the cap on the Load Variance Charge shifts approximately $20 million annually to energy charges. *Id*. BPA responded in rebuttal that it is necessary to keep the price caps as proposed. Burns and Elizalde, WP-02-E-BPA-37, at 11. This is based on the need to balance the competing goals of pricing products to reflect costs versus concern over the degree of rate impact in spreading the benefits of the FCRPS. *Id*. BPA is mindful that its rates, taken in total, must recover BPA's costs, taken in total. While BPA is moving toward a rate design for power products that appropriately sends price signals at the margin, BPA believes that there would be unreasonable rate impacts for some customers if BPA designed rates to fully reflect market signals. *Id*. BPA believes the 2002 power rates balance the competing goals of rate stability and product pricing to reflect cost. *Id*.

The HLFG's recommended mitigation alternative, Koehler *et al*., WP-02-E HL-01, at 29; includes aspects of BPA's rate proposal that are broader than the forms of rate mitigation BPA has offered. The HLFG included elements of BPA's initial proposal which the HLFG asserted "deliberately or inadvertently shift costs among customers and types of loads." *Id*. The HLFG identifies: (1) the cap on the Load Variance Charge; (2) two kinds of caps on the Demand Charge; (3) the new TBL obligation to incur incremental costs for non-Federal transmission service and the spreading of most GTA costs to all of BPA's power rates; (4) a summer/irrigation mitigation fund; (5) no-cost transmission management services for the smallest customers; (6) the LDD; and (7) the implementation of the rate collars in pre-Subscription contracts. *Id*. The HLFG alleged cost shifts of over $100 million annually without providing any supporting analysis or evidence to make a demonstration of any actual cost shifts. *Id*.

BPA agrees with the position taken by NRU that the HLFG's mitigation package is unsupported by any evidence. NRU Brief, WP-02-B-NI-02, at 7. The HLFG's proposal is further attenuated by inclusion of such a broad array of rate elements, which as a threshold matter, were either addressed by BPA to the extent a specific element was at issue in this rate case or were simply not claimed by the HLFG as causing cost shifts. Moreover, no evidence in the record supports the claim made by the parties that the rate elements identified by the HLFG would cause cost shifts of $100 million annually. For example, BPA rebutted the HLFG's argument regarding the caps on both the Demand and Load Variance Charges as described above. Burns and Elizalde, WP-02-E-BPA-37, at 11. Therefore, BPA rejects the IOUs' and PGE's recommendation that BPA adopt the HLFG's recommendations. BPA does not agree that the HLFG's recommendation will better effectuate BPA's policy goals. To the contrary, BPA believes it is more reasonable to rely on the forms of rate mitigation it has proposed to effectuate its policy goals than to adopt the unsupported recommendation made by the HLFG.

In contrast to the IOUs and PGE, WPAG and PNGC argue that the level of the cap for the Demand Charge should be lowered. WPAG claims the annual cap on the proposed Demand Charge is the minimum mitigation action needed to protect BPA's small and medium sized preference customers from substantial adverse impacts from the proposed Demand Charge increase. WPAG Brief, WP-02-B-WA-01, at 19. WPAG recommends that BPA adopt an annual Demand Charge of $1.80, which WPAG states will limit the increase of the Demand Charge to a little more than 100 percent. *Id*. at 20. Similarly, PNGC argues that the proposed cap to the Demand Charge is too great, and that the other forms of rate mitigation fail to adequately redress the impacts related to the Demand Charge. PNGC Brief, WP-02-B-PN-01, at 24-27. PNGC claims that the LDD is not rate mitigation; nor will $4 million in relief available to high irrigation load customers do anything for "typical" customers that have light irrigation loads that predominantly serve residential consumers. *Id*. at 25. PNGC, therefore, recommends that the Demand and Load Variance rates be limited to increasing no more than 30 percent over PF-96 rates or $1.13 for capacity on an annual average basis, and 0.42 mills/kWh for Load Variance Charges. *Id*.; Gonzales *et al*., WP-02-E-PN-04, at 3.

BPA again notes that these particular caps were selected based on a balancing of competing goals of wanting product pricing to reflect cost, and on the other hand, concern about the degree of rate impact as one consideration in spreading the benefits of the FCRPS. Burns and Elizalde, WP-02-E-BPA-08, at 18. BPA is aware that there would be impacts among the customers depending on their load shapes and usage. *Id.* By the changes in the Demand and Load Variance Charges, BPA is attempting to price its products such that they reflect costs to BPA. *Id.*

It is necessary to keep the price caps as proposed because of the need to balance the competing goals of pricing products to reflect costs versus concern over the degree of rate impact in spreading the benefits of the FCRPS. Burns and Elizalde, WP-02-E-BPA-37, at 11. Charging full market price would have unreasonable rate impacts for some customers. Burns and Elizalde, WP-02-E-BPA-08, at 18. While BPA is moving toward a rate design for power products that appropriately sends price signals at the margin, BPA believes that there would be unreasonable rate impacts for some customers if BPA designed rates to fully reflect market price signals. *Id.* The proposed caps provide rate mitigation in addition to other forms of mitigation BPA is offering. *Id.* Although PNGC claims the LDD is not a rate mitigation tool, the LDD when taken together with forms of rate mitigation certainly provides eligible customers rate relief. *See* Gustafson *et al*., WP-02-E-BPA-23. To at least partially mitigate rate impacts on seasonal loads, the 2002 rates continue the flexible PF rate while still maintaining the same amount of revenues for BPA. *Id.* The $4 million is, in the professional judgment of BPA's witnesses, an amount of money that will help to offset rate impacts for some customers and still allow BPA to meet its PF rate targets. *Id.*

Another issue PNGC raises in relation to the caps is the Demand Adjuster. PNGC notes that its recommendation, which was that the Demand Adjuster not be applied to Actual Partial Service-Simple (APS-S), went unrebutted. PNGC Brief, WP-02-B-PN-01, at 26. PNGC states that calculating the Demand Adjuster using Total Retail Load (TRL) and then applying it to the Demand Entitlement results in a higher demand than actually placed on BPA when BPA is meeting its peak demands in every instance. *Id*. PNGC's witnesses concluded that APS-S service should be billed for demand at the hour of the BPA Generation Peak and not include the Demand Adjuster. *Id*.

BPA does not agree with PNGC's recommendation. In rebuttal BPA responded to a similar recommendation made by WPAG, which is equally applicable to PNGC's recommendation made in its brief. BPA notes that the product intent was to create demand billing parity for partial product purchasers in comparison to full service purchasers. Keep *et al*., WP-02-E-BPA-43, at 10. This was done in light of the BPA proposal to bill full service purchasers for demand on the BPA Generation System Peak (GSP) hour. *Id*. A customer with a flat resource leaves BPA with a "peakier" load than a customer that has a resource that follows part of its load shape. BPA's overall price signal to customers is intended to be that their mills/kWh effective rate should increase as the load factor placed on BPA decreases, *i.e.*, becomes more peaky. *Id.* The Demand Adjuster was not intended to change that. PNGC's proposed change would make the price signal to a customer that uses a flat resource the same as a customer whose resource followed a portion of its load, as long as both customers are using the same energy amounts on BPA's system peak, even though the flat resource can leave BPA with the fluctuations of the customer's load to follow. This effective rate difference results in a price signal and also a proportionate distribution of the responsibility for paying a portion of BPA's revenue requirement. *Id*. In rebuttal, BPA pointed out that WPAG's proposed method would result in a lower Demand Charge as the GSP delivery amount decreased, whether or not the customer was helping to reduce the factoring service placed on BPA. *Id*. Under the WPAG method, a customer who supplied a flat diversification resource to its load would have chosen to place a higher load factor on BPA than a customer who supplied an equal MW amount on the GSP hour, but attempted to follow a portion of its own load placed on BPA. The recommendation made by WPAG's witnesses as to how to calculate the Demand Adjuster has the same end result for a flat diversification as the proposal made by PNGC as applied to the APS-S service. As BPA witnesses testified, this would weaken the price signal regarding choices that increase peaky load placed on BPA. *Id*. It also would counteract BPA's intention to distribute proportionate responsibility for payment of the revenue requirement to customers consistent with the obligations they place on BPA. *Id*.

<u>Decision</u>

BPA will cap Demand and Load Variance Charges at the levels set as part of its rate mitigation package to protect customers from excessive rate increases due to rate design changes.

10.4 <u>Demand Charges</u>

The Demand Charge is a $/kW per month charge that compensates 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.

The method for computing the Demand Charges uses hourly values minus annual average values of market forecast prices. The method computes a delta which is the average of all the positive differences between hourly and annual average values. This delta reflects the cost of serving firm hourly loads. This annual average delta is converted to a five-year average and then shaped to AURORA average monthly onpeak prices, resulting in 12 monthly Demand Charges. More value is attributed to months where BPA faces higher prices that may result in higher costs to serve load. Less value is attributed to months where BPA faces lower prices that may result in lower costs to serve load. Since BPA did not propose hourly rates, the Demand Charge is needed to reflect firming costs and hourly price differentials. The Demand Charge plus energy rates tend to mimic the effect that hourly pricing would have had on the customer's effective mills/kWh rate. Keep *et al.*, WP-02-E-BPA-17, at 3-5. In order to mitigate the rate impact of the Demand Charge, BPA has capped it at a maximum of $2.50/kW per month, and at a maximum of $2.00/kW per month on an annual average basis. Keep *et al.*, WP-02-E-BPA-17, at 5; Burns and Elizalde, WP-02-E-BPA-08. Monthly demand rates are shown in the Wholesale Power Rate Schedules, Appendix 1, WP-02-A-02, section II.A. Demand Rate Table.

The source of data used for the market forecast is the Marginal Cost Analysis Study, WP-02-FS-BPA-04. This study uses the AURORA Model to estimate a market-clearing price forecast. The forecasted hourly prices are used to derive the Demand Charge. *See* Wholesale Power Rate Development Study, WP-02-E-BPA-05, section 2.3.1.2.1.

Issue 1

Whether the Demand Charge calculation method should be revised to use the annual energy prices across only the HLH period for each year of the rate period.

Parties' Positions

WPAG argues that the demand component of the PF rate does not accurately capture the value of firming, factoring, and peaking service provided under the PF rate. The Demand Charge should be calculated using the annual average energy prices across only the heavy load period for each year of the rate period. WPAG Brief, WP-02-B-WA-01, at 16-17.

BPA's Position

WPAG's assertion that these services are typically needed only in HLH is incorrect. Keep *et al*., WP-02-E-BPA-43, at 7. Including LLH prices in the annual average energy prices rather than just the HLH prices does not overstate the value of firming, factoring, and peaking. *Id*.

Evaluation of Positions

WPAG argues that during LLH periods BPA has more energy available than it can easily find loads to serve. WPAG Brief, WP-02-B-WA-01, at 17. The firming, factoring, and peaking services provided by the PF rate should be valued during the period that they are provided, and during the period that the market recognizes the value of such service, which is the heavy load period. *Id*. As a consequence, the calculation of the Demand Charge should not use the annual average energy prices across all hours for each year during the rate period. *Id*. WPAG contends that the proper threshold for the calculation of the demand component of the PF rate is the annual average energy prices across the heavy load period for each year of the rate period. *Id*.

WPAG argues that during LLH periods BPA has more energy available than it can easily find loads to serve. WPAG Brief, WP-02-B-WA-01, at 17. While WPAG is correct in its statement, WPAG fails to recognize that the Demand Charge is not billed on LLH. BPA's rate design sufficiently reflects a price signal regarding the HLH/LLH distribution of firming, factoring, and peaking costs, because the Subscription product billing factors for Demand are set in HLH only. Keep *et al*., WP-02-E-BPA-43, at 6. BPA testified that the demand method it chose necessitates using LLH pricing to capture the services of firming, factoring, and peaking by accounting for the differences in prices of all hourly energy prices across the year. *Id*. at 7. Demand cost is inherent in all hourly prices and not just in the HLH prices. There is some demand cost reflected in the difference between HLH and LLH prices. The cost of this demand component would not get captured in BPA's Demand Charge if LLH prices were not included in the annual average energy price. *Id*. at 7-8.

Contrary to WPAG's argument that the Demand Charge should be calculated using the annual average energy prices across only the heavy load period for each year of the rate period, BPA testified that firming and factoring are clearly used and needed in all hours where a variable generation resource must be managed and backed up to be delivered to a firm load. Keep *et al*., WP-02-E-BPA-43, at 7. BPA believes that including LLH prices in the annual average energy prices rather than just the HLH prices does not overstate the value of firming, factoring, and peaking. *Id*. Factoring FBS generation among LLH, in view of the differences between hourly LLH market prices, incurs cost. Open energy markets clearly display the hourly differentials among LLH, so firming and factoring for LLH obligations must reflect that hourly cost differential. *Id*. BPA testified further that viable commodity markets have not yet developed for unbundled stand-ready power products such as firming or factoring, as BPA uses those terms for Subscription products. *Id*. This is not because such products are not applicable outside of HLH or because they have no value. Rather, the reason for this is because such products tend to arise in connection with requirements service, such as provided by BPA, which is not usually represented among the array of commodity products that open markets tend to trade. *Id*.

WPAG also gives several reasons why BPA should adopt WPAG's proposed approach to calculating the Demand Charge. First, WPAG points out that BPA is striving for no rate increase to the average PF rate in this case. WPAG claims that if BPA retains its current PF rate Demand Charge approach, the Demand Charge will increase by over 150 percent. WPAG Brief, WP-02-B-WA-01, at 17. WPAG asserts that this is an unprecedented increase proposed at a time when there has been no material change to either the FBS resources supplying this product or to the market that is supposedly serving as a guide to BPA's rate design. *Id*. Second, WPAG contends that BPA has no compelling rationale to justify BPA's high Demand Charge. *Id*. at 18. WPAG asserts that it is not the case that BPA needs the increase in the Demand Charge to provide more revenue stability during the rate period. WPAG claims that because the preponderance of power products being offered by BPA to customers have a take-or-pay element, BPA will have a guaranteed revenue stream that is more predictable than that provided by a high Demand Charge. *Id*. WPAG states that as a result of the increase in the PF rate Demand Charge, BPA has had to substantially reduce the price it will charge for energy to avoid overcollecting its revenue requirement. *Id*. Consequently, BPA will be charging an energy rate that will be below the market rate for energy that is being predicted by the AURORA Model, and BPA's energy rates will be out of step with the market. *Id*. Finally, WPAG claims that the proposed Demand Charge will have an adverse impact on BPA's preference customers who have weather-sensitive loads, such as winter peaking and irrigation loads. WPAG argues that, in contrast, the methodology proposed by the WPAG direct testimony would result in an increase in the PF rate Demand Charge of about 24 percent, which is in line with the changes being made to other rate components. *Id*. WPAG claims that this one component most directly impacts BPA's small and medium sized preference customers.

BPA is not persuaded by the arguments made by WPAG. BPA's new Demand Charge definition and pricing for this rate period are more appropriate within the context of an unbundled, deregulated market. Keep *et al*., WP-02-E-BPA-17, at 6. In BPA's direct testimony, BPA described the changes in the Demand Charge computation from that used in the 1996 rate case. The MCA in the 1996 rate case computed values for capacity based on the costs of new resource additions. *Id*. at 5. Those values were used to derive the Demand Charge. This charge was averaged over all months, resulting in a single Demand Charge rate. *Id*. The Marginal Cost Analysis Study, WP-04-FS-BPA-04, for this rate case uses the AURORA Model, which does not compute capacity values. It computes only hourly energy prices, and therefore, because energy rates are derived using AURORA hourly prices, it is appropriate to derive a Demand Charge from AURORA. *Id*. This Demand Charge is shaped by month to reflect market prices. *Id*. The 1996 rate case defined demand as standing ready to serve instantaneous peakload, and the cost was derived from the capital costs of new resources. In that rate case, BPA charged as though it would acquire new generation resources to meet load. *Id*. In comparison to the computation in this rate case, unbundling as it has developed in the deregulated market has resulted in a more specific inclusion of expected market purchases for the supplier's portfolio of resources to serve its load. *Id*. at 6. Such purchases are made from markets that use hourly energy prices. Unbundling has also resulted in specific identification of risks such as price risk. *Id*. Due to the need to make market purchases as necessary, BPA undertakes price risk when it provides firming and stand-ready services to actual customer loads as part of firm requirements products. Loads that are not flat will cause peaks to occur in the market that will drive hourly prices higher during these peaks. *Id*.

BPA does not agree that WPAG's method for calculating the Demand Charge better reflects the market value of the service. BPA believes that WPAG's method undervalues demand. Keep *et al*., WP-02-E-BPA-43, at 8. BPA examined WPAG's proposed calculations and determined that they fail to capture the value for demand that is reflected by including the LLH in the average annual price, and thus would undercollect costs. *Id*. BPA's method is built on the premise that if a load were flat and BPA were to charge a single rate, then the annual average price would collect all costs. This works for a flat load, but not necessarily for a shaped load. *Id*. Therefore, to allocate costs equitably for shaped and flat loads, BPA's 2002 power rates include a monthly Demand Charge and monthly HLH and LLH energy charges. These monthly charges would result in the flat load paying the same charge as it would pay under a single annual average charge. *Id*. The shaped load would pay more or less than the average annual charge depending on whether the load was shaped into HLH or LLH or shaped into more or less costly months. *Id*.

Decision

The Demand Charge calculation method will not be revised.

Issue 2

Whether BPA should apply the Demand Adjuster to customers taking APS-S service.

Parties' Positions

PNGC notes that its recommendation that the Demand Adjuster not be applied to APS-S went unrebutted. PNGC Brief, WP-02-B-PN-01, at 26. PNGC claims that calculating the Demand Adjuster using TRL and then applying it to the Demand Entitlement would result in a higher demand than actually placed on BPA when BPA is meeting its peak demands in every instance. *Id*. PNGC concluded that APS-S service should be billed for demand at the hour of the BPA Generation Peak and not include the Demand Adjuster. *Id*.

BPA's Position

BPA's Demand Adjuster methodology is specified in the Power Products Catalog, Appendix A, Product Billing Factors. Keep *et al*., WP-02-E-BPA-43, at 10. The product intent was to create demand billing parity for partial product purchasers and full service purchasers. *Id*. This was done in light of the BPA proposal to bill full service purchasers for demand on the BPA GSP hour. *Id*.

Evaluation of Positions

PNGC notes that its recommendation that the Demand Adjuster not be applied to APS-S went unrebutted. PNGC Brief, WP-02-B-PN-01, at 26. PNGC noted that an APS-S customer brings in a flat block at the bottom of its load. Gonzalez and Sher, WP-02-E-PN-04, at 7. PNGC contends that calculating the Demand Adjuster using TRL and then applying it to the Demand Entitlement results in a higher demand than actually placed on BPA when BPA is meeting its peak demands in every instance. *Id*. PNGC recommended that APS-S service should be billed for demand at the hour of the BPA Generation Peak and not include the Demand Adjuster. *Id*. Further, BPA should amend its schedules to remove application of the Demand Adjuster from APS-S. *Id*.

BPA does not agree with the recommendation in PNGC's brief. In rebuttal testimony BPA responded to a similar recommendation made by the WPAG. BPA notes that the intent for the product was to create demand billing parity for partial product purchasers and full service purchasers. Keep *et al*., WP-02-E-BPA-43, at 10. This was done in light of the BPA proposal to bill full service purchasers for demand on the BPA GSP hour. *Id*. As PNGC correctly points out, an APS-S customer will use a flat resource. However, a customer with a flat resource places BPA in a position of needing to serve a "peakier" load, as opposed to a customer that has a resource that follows some or most of its load shape. BPA's overall price signal to customers is intended to be that the customer's mills/kWh effective rate should increase as the load factor placed on BPA decreases, *i.e*., becomes more peaky. The Demand Adjuster was not intended to change that. PNGC's proposed change would make the price signal to a customer that uses a flat resource the same as a customer whose resource follows a portion of its load, as long as both customers are using the same energy amounts on BPA's GSP, even though the customer using the flat resource puts BPA in the position of serving the fluctuations, *i.e*., peaks, in its load. This runs counter to BPA's intended price signal. The effective rate difference results in a price signal and also a proportionate distribution of the responsibility for paying a portion of BPA's revenue requirement. *Id*. In rebuttal, BPA pointed out that WPAG's proposed method would result in a lower Demand Charge as the GSP delivery amount decreased, whether or not the customer was helping to reduce the factoring service placed on BPA. *Id*. Under the WPAG method, a customer who supplied a flat diversification resource to its load would have chosen to place a peakier load on BPA than a customer who supplied an equal MW amount on the GSP hour but attempted to follow a portion of its own load placed on BPA. The recommendation made by PNGC as to how to calculate the Demand Adjuster methodology has an end result similar to that of WPAG's proposal as applied to the APS-S service. BPA witnesses testified that this would weaken the price signal regarding choices that increase peaky load placed on BPA. *Id*. It also would counteract BPA's intention to distribute proportionate responsibility for payment of the revenue requirement to customers consistent with the obligations they place on BPA. *Id*.

<u>Decision</u>

BPA will apply the Demand Adjuster to customers taking APS-S service.

10.5 <u>Load Variance Charge</u>

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 they are served by BPA under the applicable firm power rate. Keep *et al.*, WP-02-E-BPA-17, at 7. Details of the product and rate case considerations and issues are discussed below.

The Load Variance service shifts the planning risk to BPA for all variations between actual and forecasted retail loads. With Load Variance, BPA will deliver additional power at the PF or NR rate to meet variations in retail load above forecast and will reduce PF or NR deliveries for variations in retail load below forecast. The Load Variance product is available to Full and Actual Partial utility customers under 2002 Subscription contracts. The Load Variance Charge under the Full and Actual Partial Service products entitles customers' billing factors to follow actual consumption. This differs from Block products, where the amounts to be paid are fixed. Keep *et al.*, WP-02-E-BPA-17, at 7.

The Load Variance Charge is applied to TRL (as defined in the General Rate Schedule Provisions, GRSPs), because under the Subscription core products, BPA's service applies to the entire TRL even if the customer dedicates some resource amounts to service its load. If the Load Variance Charge were applied only to net load, customers would pay unequally for the same service. Keep *et al.*, WP-02-E-BPA-17, at 13.

BPA proposed to set the Load Variance Charge based on the market costs of avoiding the price risk of serving variations in load. Keep *et al.*, WP-02-E-BPA-49, at 2-3. BPA assumed that it could buy call options in the financial market to guarantee purchase prices to serve load in excess of forecast, and that it could buy put options to guarantee sale prices in the market to ensure no change in expected revenue when loads do not materialize, *i.e.*, loads below forecast. *Id*.

The Load Variance Charge was calculated by computing load growth amounts from the five-year monthly forecast of TRL as reflected in the NWPPC's forecast of public and Federal agencies' TRL. Loads and Resources Study, WP-02-E-BPA-01 and Loads and Resources Study Documentation, WP-02-E-BPA-01A. The cost to serve load growth was calculated using call option pricing. Load variation was estimated to have a 3.7 percent average upside variation and a 0.4 percent average downside variation. These variations were determined by comparing regional combined load forecasts for generating and non-generating public utilities to subsequent actual loads for the period October 1990, through September 1995. The cost to serve load variation was calculated using call option pricing for upside variation and put option pricing for downside variation. A detailed explanation of the derivation of the rate can be found in the Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 18-20.

This Load Variance option pricing method resulted in a cost of 1.19 mills/kWh on forecasted TRL. Keep *et al.*, WP-02-E-BPA-17, at 17. To mitigate the rate impact relative to PF-96, the cost of 1.19 mills/kWh was capped at 0.80 mills/kWh. *Id*. A description of the reasons for capping the rate is described in Burns and Elizalde, WP-02-E-BPA-08.

Issue 1

Whether the Load Variance Charge should be revised because it overstates the value of service BPA provides.

Parties' Positions

WPAG and SUB agree that the proposed Load Variance Charge should be capped but, they argue, it is substantially overstated and should be revised in order to reflect the value of the service BPA provides. WPAG Brief, WP-02-B-WA-01, at 20; SUB Brief, WP-02-B-SP-01, at 6.

SUB also argues that the Load Variance charge should include a component priced at the unit cost of FBS resources. *Id*. SUB reiterates its arguments and claims its positions on Load Variance were ignored in the Draft ROD. SUB Ex. Brief, WP-02-R-SP-01, at 7.

<u>BPA's Position</u>

BPA argued that the Load Variance charge reflects the value of the service, that it is not overstated, and that it should not be revised. Keep *et al*., WP-02-E-BPA-43, at 17-19. BPA is not allocating or functionalizing specific costs to any individual product or billing factor. Keep *et al*., WP-02-E-BPA-43, at 12. BPA has used some proxy pricing approaches to develop "price-signal" rates for certain billing factors such as Load Variance. *Id*.

<u>Evaluation of Positions</u>

WPAG argues that the proposed Load Variance Charge is substantially overstated and should be revised in order to properly reflect the value of the BPA service. WPAG Brief, WP-02-B-WA-01, at 20. WPAG suggests that BPA make the following revisions: eliminate the risk costs that are already being collected in PNRR; remove the costs of expected growth already included in the PF and NR rates; use a bandwidth for the deviations above and below the forecast of +/- 2.05 percent; and credit the revenue forecast to be collected from the Load Variance Charge to only the PF and NR rates. *Id.*

WPAG's first suggested revision is to eliminate the risk of costs that are already being collected in the PNRR. WPAG contends that the costs of weather and load included in the calculation of the Load Variance Charge are being double-counted, because they are also included as potential cost exposure in the amount of PNRR BPA needs to collect. WPAG Brief, WP-02-B-WA-01, at 20. BPA stated in testimony that PNRR includes a cost for risk associated with the published rate for the Load Variance Charge. Keep *et al*., WP-02-E-BPA-43, at 17. The risk is based on the possibility that any and all Subscription sales, including the Load Variance service, may not recover BPA's revenue requirement; therefore, no customers will be double-charged by applying the Load Variance Charge. *Id*. at 18. BPA's forecast of revenue from Load Variance Charges is netted out of the total revenue requirement prior to computing the PF and NR energy rates; therefore, no customers are double-charged for PNRR. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 52, lines 1 and 2.

WPAG's second suggested revision is to remove costs of weather variations and expected load growth from the Load Variance Charge because they are already included in PF and NR rates. WPAG Brief, WP-02-B-WA-01, at 20-21. WPAG argues that customers are being double-charged for the costs of load growth. *Id*. WPAG claims that including forecast load growth in the calculation of the Load Variance Charge, when such costs have already been included in the PF rate, amounts to double-counting the costs of this load growth and unnecessarily inflates the level of the Load Variance Charge. *Id*. WPAG contends that the Load Variance Charge should be calculated on the basis of unforeseen load variations, and not include load growth that is forecast. *Id*. at 21.

Removing weather variations and load growth costs from the Load Variance Charge would cause an underrecovery of revenue requirement or an increase in other PF rates. BPA should not remove the cost components related to weather and load growth variations from the Load Variance Charge. Keep *et al*., WP-02-E-BPA-43, at 17. BPA testified that because it is not allocating costs directly to specific billing determinants, BPA estimates what it might cost if BPA decided to separately cover monthly energy uncertainty with an option. *Id*. at 17. BPA then uses that estimate to come up with a price-signal rate for load variance. Keep *et al*., WP-02-E-BPA-43, at 17. The estimated revenues from the Load Variance Charge reduce the revenue requirement that the PF energy rates must recover. The costs associated with load variance are first calculated, then capped, and then removed from the revenue requirement. Keep *et al*., WP-02-E-BPA-43, at 19. BPA testified further that its forecast does not show that it will have surplus firm power available on an annual basis to meet load growth during the rate period. Charging for load growth in the Load Variance Charge provides BPA cost coverage for the cost associated with increasing the FBS to serve customers' load growth at PF rates. *Id*. at 18.

WPAG's third suggested revision is for BPA to use a bandwidth for deviations above and below the forecast of +/- 2.05 percent. WPAG Brief, WP-02-B-WA-01, at 21. WPAG contends that without such a bandwidth, BPA's calculation would be statistically unsound. *Id*. WPAG states that it should be assumed that unforeseen variations from forecast will be random, and such variations will occur above forecast as often as they will occur below the forecast. *Id*. WPAG's testimony on the Load Variance Charge suggested that BPA use the forecast and actual loads for the combined group of utilities to calculate the monthly load deviations, and then take the averages of the positive and negative differentials over the five-year test period. Cross *et al*., WP-02-E-WA-01, at 56. Using this method results in a 3.7 percent positive and 0.4 percent negative deviation from the 1991 forecast. *Id*. WPAG's witness concluded that given an equal spread of probable loads, the simple average of 2.05 percent ((3.7 + 0.2)/2) should be used for the positive and negative deviations. *Id*. at 57. SUB agrees with WPAG's argument. SUB Brief, WP-02-B-SP-01, at 6.

In rebuttal, upon examination of the data described in WPAG's testimony, BPA determined that the distribution of actual load around the forecast is approximately equal in magnitude when looking at the maximum deviation above and below the forecast. Keep *et al*., WP-02-E-BPA-43, at 19. However, more occurrences are observed of loads above forecast than below forecast. *Id*. Therefore, the average error above the forecast is greater than the average error below the forecast. BPA's analysis results in a 3.8 percent positive and a 0.7 percent negative deviation from the forecast. Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05B, at 2. BPA concludes that a uniform bandwidth for deviations above and below the forecast is not appropriate.

WPAG's final suggested revision is for BPA to credit the revenue forecast from the Load Variance Charge to only the PF and NR rates. WPAG Brief, WP-02-B-WA-01, at 21. WPAG argues that crediting the Load Variance revenues to all firm power rates provides a subsidy to purchasers under the RL and IP rates by allowing them to share the revenues from a charge that they are not required to pay, creating an inequitable cost shift. *Id*.

BPA does not agree with WPAG's contention that BPA will provide a subsidy to purchasers under the RL and IP rates by crediting revenues to all firm power rates, including the RL and IP rates, which are not subject to the Load Variance Charge. BPA has testified that it is not allocating costs directly to specific billing determinants. Keep *et al*., WP-02-E-BPA-43, at 17. Instead, BPA estimates what it might cost if it decided to separately cover monthly energy uncertainty with an option. *Id.* This estimate is used to come up with a price-signal rate for Load Variance. *Id*. BPA is not necessarily going to buy such options to cover a specific subset of BPA's loads. *Id*. BPA will actually be covering total Subscription inventory and load uncertainty simultaneously through a portfolio of long- and short-range approaches. *Id*. Moreover, BPA estimated the cost of the Load Variance service and forecasted that the revenues from the Load Variance product will exactly equal those costs; therefore, there is no subsidy to a class of customer that does not purchase the Load Variance service.

SUB's brief on exceptions notes that the Draft ROD ignored SUB's positions on Load Variance in its initial brief and encourages BPA to address SUB's comments. SUB Ex. Brief, WP-02-B-SP-01, at 7. SUB argues that because BPA "can meet a portion of Load Variance service to Preference Customers with the flexibility in the FBS, the Load Variance charge should include a component priced at the unit cost of FBS resources." SUB Brief, WP-02-B-SP-01, at 6. BPA understands SUB's proposition to mean that SUB believes BPA's system has flexibility to operate and provide additional energy or resell unused energy in periods in which BPA is called upon to provide customers with Load Variance service. However, the Load Variance Charge approximates the amount of incremental or marginal cost risk BPA must bear in providing Load Variance service. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 18. The risk is standing ready to serve an unknown quantity at an unknown cost, but at a fixed price. *Id*. When loads are above or below the forecast, BPA could purchase or sell in the market at an unknown price. *Id*. BPA has reviewed SUB's suggestion, but as stated in testimony, the Load Variance charge was developed using a proxy pricing approach that results in a "price-signal rate." Keep *et al*., WP-02-E-BPA-43, at 12. That should not be confused with saying that those are BPA's plans of service or that BPA will actually incur costs in such an earmarked way. *Id*. BPA will actually be planning and operating to match generation plus other inventory to all load BPA is obligated to serve under existing and Subscription contracts. *Id*.

Finally, SUB agrees with BPA's decision to cap the Load Variance charge. In its initial brief, SUB quotes the following from the Energy and Water Development Act of 1993:

> . . . none of the funds made available under this Act, subsequent Energy and Water Development Appropriations or any other law hereafter shall be used for the purposes of conducting any studies relating or leading to the possibility of changing from the currently required "at cost" to a "market rate" or any other noncost-based method for the pricing of hydroelectric power by the six Federal public power authorities, or other agencies or authorities of the Federal Government, except as may [sic] specifically authorized by Act of Congress hereafter enacted.

SUB Brief, WP-02-B-SP-01, at 6, quoting 42 USC 7152. SUB argues in its brief on exceptions that BPA (in complying with 42 U.S.C. 7152) cannot conduct studies which lead to the charging of power at market rates, particularly for a product which applied for general service for core subscription products. SUB Ex. Brief, WP-02-R-SP-01, at 7. SUB does not state how the above statute relates to this current section 7(i) proceeding. Nor does SUB allege one way or the other regarding the use of appropriated funds to conduct any studies whatsoever. Therefore, BPA does not find this particular statutory reference relevant to setting cost-based rates in this proceeding.

Decision

BPA has determined that the methodology used to calculate the Load Variance Charge is appropriate and does not overstate the value of service BPA provides.

Issue 2

Whether the Load Variance billing factor uses the wrong baseline to calculate Load Variance Charges.

Parties' Positions

PGP argues that a billing factor based on TRL is improper ratemaking, because it bases a charge for a variable load on a fixed retail load. PGP Brief, WP-02-B-PG-01, at 6-8; PGP Ex. Brief, WP-02-R-PG-01, at 3-6. PGP argues that the Load Variance service should instead be based on factors that account for the variable nature of the proposed service. *Id*. PGP and the DSIs argue that customers with stable or constant loads will absorb costs of those customers with fluctuating loads. *Id*.; DSI Brief, WP-02-B-DS-01, at 80. Cowlitz joins PGP's exceptions and independently preserves its exception that the proposed billing factor is not based on the actual variable loads that create cost of service for BPA. Cowlitz Ex. Brief, WP-02-R-CO-01, at 2-6.

BPA's Position

BPA does charge the Load Variance charge to those loads that fluctuate, but based on an average across all public generating and non-generating loads. Keep *et al*., WP-02-E-BPA-43, at 15. This is consistent with the overall rate design of billing on a common table of rates. *Id*. A customer whose load does not vary has the option of purchasing a Block product that does not incur the Load Variance Charge. If a customer's load does vary, it could still purchase a Block product and cover load variation from the market or through a negotiated FPS product from BPA. *Id*.

Evaluation of Positions

PGP argues that TRL is a fixed load. PGP contends that BPA's proposal relies on a faulty comparative analysis of the proposed Load Variance Charge. PGP Brief, WP-02-B-PG-01, at 6. BPA's method uses a fixed base to measure a fluctuating variable. *Id*. PGP claims that BPA customers with relatively flat loads, or even customers with no load, will bear an unequal proportion of costs for the Load Variance service compared to those customers that actually have load variations. *Id*. at 6-7. TRL is not a fixed load. Keep *et al*., WP-02-E-BPA-17, at 7. Load Variance applies to the variability in monthly energy consumption within the BPA customer's system. *Id*. Inherent in the TRL is the variability caused by weather, economic business cycles, load growth, and load loss. *Id.* BPA stands ready to serve this variability under the Full and Actual Partial service products. *Id*. The service entitles customers' billing factors to follow actual consumption.

PGP and Cowlitz argue BPA does not support with any evidence or testimony in the record when and how often weather (or other unnamed factors for that matter) proportionally affect the proposed Load Variance billing. PGP Ex. Brief, WP-02-R-PG-01, at 5; Cowlitz Ex. Brief, WP-02-R-CO-01, at 2-3. They contend, without any support, that it is "indisputable that the loads of certain industrial customers are largely unaffected by weather fluctuations." *Id*. They conclude, "Bonneville wrongly assumes that weather affects the TRL of all customers equally." *Id*.

PGP and Cowlitz focus on this narrow example of load variation to argue that Load Variance should not be based on TRL, but rather on the actual variance for which it seeks recovery of its costs. PGP Ex. Brief, WP-02-R-PG-01, at 5; Cowlitz Ex. Brief, WP-02-R-CO-01, at 2-3. Their argument is not persuasive. BPA notes that variability in monthly energy consumption may be caused by factors other than weather, such as economic business cycles, load growth, or load loss. Keep *et al*., WP-02-E-BPA-17, at 7. It is not isolated to any one specific event occurring in the month. BPA does charge those loads that fluctuate, but based on an average across all public generating and non-generating loads. Keep *et al*., WP-02-E-BPA-43, at 15. This is consistent with the overall rate design of billing on a common table of rates. *Id*. A customer whose load does not vary has the option of purchasing a Block product that does not incur the Load Variance Charge. If a customer's load does vary, it could still purchase a Block product and cover load variation from the market or through a negotiated FPS product from BPA. *Id*.

BPA's Load Variance Charge is based on historical forecast data, actual resulting load data, and a load growth forecast. Keep *et al*., WP-02-E-BPA-17, at 6. BPA testified that Load Variance service costs are a function of the size of the potential change in load, and the size of potential changes in load is a function of the absolute size of the total load. Keep *et al*., WP-02-E-BPA-43, at 14. Further, the Load Variance Charge was based on observed deviations from forecast. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05B, section 4.1. The cost of those deviations is spread over TRL. Keep *et al*., WP-02-E-BPA-43, at 14. Therefore, TRL is an appropriate billing factor, because the potential changes in load are a function of TRL. *Id.*

<u>Decision</u>

The billing factor for Load Variance has the appropriate baseline to calculate the customer's TRL.

<u>Issue 3</u>

Whether the TRL billing factor should exclude Block purchases.

Parties' Positions

PGP argues that because BPA's proposed TRL billing factor is an inaccurate method to bill variable loads, which creates a cross-subsidy requiring customers with relatively stable or constant loads to absorb costs of customers with fluctuating loads, BPA should instead focus on actual or contracted monthly load variances to calculate its Load Variance billing factor. PGP Brief, WP-02-B-PG-01, at 7. An example, given by the PGP, is to exclude Block power purchases from the TRL billing factor, because a Block power sale does not vary. *Id*. at 8. PGP and Cowlitz maintain that block power purchases should be excluded from the TRL when calculating Load Variance charges. PGP Ex. Brief, WP-02-R-PG-01, at 6-7; Cowlitz Ex. Brief, WP-02-R-CO-01, at 4-5. Both parties contend that BPA's rationale for including block power purchases in the calculation is not factually grounded, nor supported by any evidence in the record. *Id*.

BPA's Position

TRL is the appropriate billing factor to calculate the Load Variance charge. Keep *et al*., WP-02-E-BPA-43, at 14. TRL should not exclude Block purchases. While the amount of power in a Block purchase will not vary, the underlying load is not affected and will still vary proportionately due to weather, economy, and load growth. Keep *et al*., WP-02-E-BPA-43, at 16.

Evaluation of Positions

PGP argues for a remedy to escape what it contends is a cross-subsidy provided by customers with relatively flat or constant loads to customers with fluctuating loads. PGP Brief, WP-02-B-PG-01, at 7. PGP and Cowlitz contend that the record is devoid of support for BPA's conclusion that "[t]he variation in TRL includes any variation of the underlying load." PGP Ex. Brief, WP-02-R-PG-01, at 6; Cowlitz Ex. Brief, WP-02-R-CO-01, at 4. PGP suggests a remedy, which is to exclude from the TRL any Block power purchases. *Id*.

BPA does not agree with the PGP and Cowlitz position. The record supports BPA's conclusion. PGP and Cowlitz note that "loads that cannot vary, due to contractual obligations, are by definition excluded from causing any variation in the load placed on Bonneville." PGP Ex. Brief, WP-02-R-PG-01, at 7; Cowlitz Ex. Brief, WP-02-R-CO-01, at 5. BPA's witnesses have discussed the relationship of this type of load and the conditions that apply to it. *See* Keep *et al*., WP-02-E-BPA-43, at 11. An example of a load qualifying for an adjustment to TRL for purposes of the Load Variance Charge billing determinant would be one that BPA has no obligation to serve. Keep *et al*., WP-02-E-BPA-43, at 11. Such load must be separately hourly metered, its power supply must be hourly scheduled, and schedules and metered data must be provided to BPA. *Id*. Also, meeting the load's variation must be an obligation of a party other than BPA. *Id*. While this type of load may be exempt from the Load Variance Charge, it may be subject to other charges such as energy imbalance. *Id*. The customer-specific power sales contract will determine adjustments to TRL. *Id*. In comparison, for customers that do not have such exempt load and place BPA in the position of standing ready to meet the fluctuations in the customer's load, BPA has stated that TRL is an appropriate billing factor to calculate the Load

Variance Charge. Keep *et al*., WP-02-E-BPA-43, at 14. While BPA may agree with PGP that the Block power purchase does not vary, it does not prevent the underlying load from varying. *Id.* at 16. The variation in the TRL includes any variation of that underlying load. For example, Block service combined with a load following service such as Actual Partial service does not shift the load variation risk to the BPA customer. *Id*. The Actual Partial service would still cover the total fluctuations that occur in the TRL above Block service. *Id*. Therefore, BPA believes that the correct billing determinant with this combination is TRL. *Id*.

Decision

The TRL billing factor will not exclude Block purchases.

Issue 4

Whether BPA should negotiate a limited Load Variance service for those customers anticipating such a need.

Parties' Positions

PGP argues that BPA should negotiate a limited Load Variance service for those customers anticipating such a need, which would replace the "Total Retail Load Less Block" billing factor. PGP Brief, WP-02-B-PG-01, at 7.

BPA's Position

BPA has offered to negotiate various products under the FPS-96 rate schedule and could negotiate a service similar to Load Variance. Keep *et al*., WP-02-E-BPA-43, at 16. The FPS product would have defined limits based on the customer's specific purchase amounts, whereas the Load Variance Charge billed against TRL has no limits. *Id*. A FPS product providing this type of Load Variance service could be billed in such a way so as to replace the TRL billing factor. *Id.*

Evaluation of Positions

The parties and BPA agree on this issue.

Decision

BPA will negotiate limited Load Variance service for customers.

Issue 5

Whether the Load Variance billing factor should be redesigned.

Parties' Positions

PGP argues that an alternative for customers interested in the Full Service or APS-S service would be to design a billing factor accounting for the difference in MWh between: (1) a customer's peak load multiplied by the number of billing hours in the month; and (2) the customer's average energy load for the month. PGP Brief, WP-02-B-PG-01, at 7. PGP contends that this billing factor would provide a reasonable proxy for the amount of load subject to fluctuation. *Id*.

BPA's Position

The Load Variance Charge, in part, covers the costs for the difference between expected loads versus actual loads. Keep *et al*., WP-02-E-BPA-43, at 16-17.

Evaluation of Positions

PGP provides no evidence as to how the difference between: (1) a customer's peak load multiplied by the number of billing hours in the month; and (2) the customer's average energy load for the month would reflect the uncertainty in load. PGP argued in its direct testimony for this change. Knitter *et al*., WP-02-E-PG-01, at 6. BPA noted that PGP provides no reasoning or evidence that its suggested billing factor is a measure of load variation. Keep *et al*., WP-02-E-BPA-43, at 16. It is not reasonable for BPA to redesign the billing factor as proposed by PGP without evidence to support the change. BPA's Load Variance Charge is based on historical data and a load growth forecast. *Id.* at 16. The Load Variance Charge, in part, covers the costs for the difference between expected loads versus actual loads. *Id*. The measure of peak versus average has nothing to do with expected loads versus actual loads. *Id*. at 17. The Load Variance Charge was based on observed deviations from forecast. *Id*. at 14. The cost of those deviations was spread over TRL. *Id*. Therefore, the correct billing determinant is TRL. *Id*.

Decision

BPA will not redesign the Load Variance billing factor.

Issue 6

Whether the Load Variance Charge should apply to all customers purchasing under the PF-02 rate unless specifically excluded.

Parties' Positions

The DSIs argue that, "[u]nless specifically excluded, a Load Variance Charge of 0.8 mills/kWh applies to all customers purchasing under the PF-02 Rate." DSI Brief, WP-02-B-DS-01, at 80. The charge will be applied to the customer's TRL, as defined in the GRSPs. *Id*. The DSIs state that "[t]he current definition of TRL in the GRSPs creates considerable ambiguity in that the rate schedules fail to define the circumstances in which certain loads would be exempt from the Charge." *Id*. "The DSIs propose that BPA amend the definition of Total Retail Loads [sic] so that the Charge does not apply to loads that impose no variance on BPA even if the load varies." *Id*. The DSIs state in their brief on exceptions that BPA has misstated the issue the DSIs raised in their direct testimony, Schoenbeck and Bliven, WP-02-E-DS-03, and at pages 79-80 in their initial brief regarding the Load Variance Charge. DSI Ex. Brief, WP-02-R-DS-01, at 11.

<u>BPA's Position</u>

Subscription core products that flex to meet actual consumption will have the Load Variance Charge applied to TRL. Block product entitlement and billing amounts are fixed in advance and are not altered to reflect after the fact measured power consumption. The Block energy does not change the monthly HLH or LLH contracted Block energy amounts. Keep *et al*., WP-02-E-BPA-17, at 9.

<u>Evaluation of Positions</u>

The DSIs recommend that BPA should either specify in each rate schedule (*e.g.*, PF-02, section IV.A. 1.3 of WP-02-E-BPA-07) that the Load Variance Charge shall be multiplied by the Purchaser's TRL "less any excluded load identified by contract," or alternatively, the definition of TRL (WP-02-E-BPA-07, at 125) should provide that, for purposes of computing the amount of the monthly Load Shaping Charges, certain loads identified by contract will be excluded. DSI Ex. Brief, WP-02-R-DS-01, at 11.

BPA and the DSIs agree that the Load Variance Charge applies to all customers purchasing under the PF-02 and NR-02 rates, unless the customer's contracted services specifically exclude Load Variance service. The GRSPs do not define TRL for the sole purpose of charging for Load Variance; therefore TRL should not be redefined. The definition of TRL does not address loads that are exempt from the Load Variance Charge. Keep *et al*., WP-02-E-BPA-43, at 11. Adjustments to TRL for applying the Load Variance Charge may be determined in the power sales contract and will exclude that portion of the TRL and its associated load variation that BPA is not obligated to serve. *Id*. An example of a load qualifying for an adjustment to TRL for purposes of the Load Variance Charge billing determinant would be one that BPA has no obligation to serve. *Id*. Such load must be separately hourly metered, its power supply must be hourly scheduled, schedules and metered data must be provided to BPA, and meeting the load's variation must be an obligation of a party other than BPA. *Id*. The customer-specific power sales contract will determine adjustments to TRL. *Id*. at 12. The DSIs agree with this criteria and BPA's intent to specify any load to be excluded from the Load Variance Charge by contract. DSI Ex. Brief, WP-02-R-DS-01, at 11. The DSIs note, however, that BPA's rate schedules and GRSPs do not provide for such exclusions. *Id*. BPA agrees with the DSIs that exemption to Load Variance should be identified within contracts and the rate schedules or GRSPs.

<u>Decision</u>

The Load Variance Charge applies to all customers purchasing under the PF-02 and NR-02 rates unless the customer's contracted services specifically exclude Load Variance service. The GRSPs contain language under the definition of TRL specifying the billing determinant for the Load Variance Charge for customers with exempt loads under their power sales contracts.

10.6 Unauthorized Increase Charges

BPA's UAI Charge methodology must be viewed in context with the relevant products and the BPA requirements service obligations under such products. BPA's core Subscription products are established in a forum outside the rate case. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 10-11. UAI Charges will apply when customers have contracted for Subscription power products but take amounts of power to which they are not entitled. Customers may be able to take amounts of power from BPA which are greater than they are entitled to if they fail to supply the amounts of other resources that they have committed to provide. BPA has a substantial economic and reliability interest in assuring that customers are unambiguously motivated in all timeframes to ensure the availability and delivery of their non-BPA resource amounts. UAI Charges are avoidable if customers arrange for appropriate reserve and firming products or services. Tr. 1213-15. These products and services can be self-supplied or obtained from suppliers in the market. Only if UAI Charges are clearly not an economic alternative to such reserve and firming arrangements can BPA be assured that FCRPS reliability will not be jeopardized. Therefore, UAI Charges apply to deliveries that exceed customers' contractual entitlements for demand and energy. BPA proposed that the charges for unauthorized increases in demand in any billing month be the greater of: (1) three times the applicable standard monthly demand charge; and (2) the sum of hourly California Independent System Operator (ISO) Spinning Reserve Capacity prices for all HLH in the month. Keep *et al*., WP-02-E-BPA-17, at 17. BPA also proposed that the UAI Charge for energy for each month be the greatest of: (1) 100 mills/kWh; (2) the maximum Dow Jones (DJ) Mid-C price; and (3) the maximum hourly ISO Supplemental Energy price. *Id.* at 17-18.

Issue 1

Whether BPA lacks the authority to impose a UAI Charge that is not reflective of BPA's cost.

Parties' Positions

PPC argues that the proposed UAI Charges are not cost based as required by BPA's statutes. PPC Brief, WP-02-B-PP-01, at 34; PPC Ex. Brief, WP-02-R-PP-01, at 7. In its brief on exceptions, PPC argues that "BPA arbitrarily, capriciously and without reason rejected PPC's recommendations." PPC Ex. Brief, WP-02-R-PP-01, at 8. OURCA argues that BPA lacks the authority to impose penalties without some basis tied to the underlying service and the associated costs that BPA may incur. OURCA asserts that the charges should be eliminated or revised. OURCA Brief, WP-02-B-OU-01, at 7; OURCA Ex. Brief, WP-02-R-OU-01, at 6.

BPA's Position

BPA's UAI Charges have been developed as penalty rates, and not cost-based rates. Keep *et al*., WP-02-E-BPA-43, at 26. *See* 1993 ROD, WP-93-A-02, at 166-171. The argument that the UAI Charge should be cost-based is similar to arguments made by some parties in the 1993 and 1996 rate cases. *Id*. In both cases, the Administrator rejected those arguments. Keep *et al*., WP-02-E-BPA-43, at 26. *See* 1993 ROD, WP-93-A-02, at 166-171, and 1996 ROD, WP-96-A-02, at 321-322. Cost is only one consideration in setting the level of the UAI Charges.

Keep *et al*., WP-02-E-BPA-43, at 26; Tr. 1212-14. The intent of the UAI Charges is to deter customers from using BPA power in excess of their contractual entitlements and to impose a penalty when they do place an unauthorized increase on BPA's system. *Id*.

Evaluation of Positions

PPC argues that the foundation for BPA's proposed UAI Charges is suspect because it is not based on BPA's cost as required by statute. PPC Brief, WP-02-B-PP-01, at 37; PPC Ex. Brief, WP-02-R-PP-01, at 7. OURCA similarly contends that BPA lacks authority to impose these penalties without some explanation of or link to the underlying service and the costs that BPA may incur. OURCA Brief, WP-02-B-OU-01, at 7; OURCA Ex. Brief, WP-02-R-OU-01, at 6.

Since its inception in 1974, the UAI Charge has been developed to be a penalty and not a cost-based rate. *See* 1993 ROD, WP-93-A-02, at 169. FERC has recognized the Administrator's authority to impose a UAI Charge that is not cost-based. *United States Department of Energy--Bonneville Power Admin.*, 13 FERC ¶ 61,157, 61,340 (1980). FERC approved BPA's UAI Charge of 100 mills/kWh in the 1970s, when power costs were less than 5 mills/kWh. 1993 ROD, WP-93-A-02, at 171. FERC predicated its approval on the fact that the UAI Charge was designed to modify customers' behavior. *Id*. FERC took notice of the fact that the charge was developed to assure that BPA's customers used their own resources first to meet their firm system load obligations. *Id*. As such, FERC noted that such a charge also ensures that the power BPA's customers marketed to others was truly excess resource capability. *Id*.

The minimum UAI Charge is necessary to ensure that there is always an incentive for customers to avoid placing unauthorized demand or energy increases on BPA's system. Keep *et al.*, WP-02-E-BPA-17, at 16-17. BPA's ability to plan its service obligations for the core Subscription products, as specified in the power sales contracts, and to control its costs depends on customers accurately specifying the obligations that BPA must serve. *Id*. at 17. Any occurrences of Unauthorized Increase undermine BPA's ability to plan these service obligations and control its costs. *Id*. The minimum charges, in conjunction with the potential for higher charges tied to market indexes, should encourage customers to select those products and services they need, and deter customers from using increases as an economic alternate source for those services. *Id*.

PPC, without any support, alleges that BPA lacks the statutory authority to base its power rates and charges on "lost opportunities." PPC Brief, WP-02-B-PP-01, at 37. PPC asserts that BPA's UAI Charges are intended to account for lost opportunities. *Id*. at 34. In direct testimony, BPA described that its costs are affected by market prices, and that market indexes provide a reasonable measure of its cost exposure, either as a representation of opportunity cost or purchase costs associated with serving an unauthorized increase. Keep *et al*., WP-02-E-BPA-17, at 16. BPA states that there may be times when unauthorized increases prevent or reduce BPA sales into the ISO markets, thus creating opportunity costs associated with serving the unauthorized increases. Keep *et al*., WP-02-E-BPA-43, at 25.

While BPA considers opportunity costs in the design of the UAI Charges, the opportunity cost concept by itself is not presented as an indispensable rationale for BPA's design. BPA presents several other reasons for its design. Tr. 1213-114. Nevertheless, opportunity cost pricing is a standard pricing method. Tr. 1205. BPA relied, in part, on opportunity cost pricing in the 1996 rate proceeding and in the development of the Load Variance Charges for the current rate proceeding. Tr. 1205. Also, in the 1985 rate case, BPA priced the first quartile of the DSI loads based on the opportunity cost of serving the first quartile with nonfirm energy. 1985 ROD, WP-85-A-02, at 150-155. It is appropriate for the UAI Charges to constitute a penalty, rather than to be tied to some cost basis. BPA adopts the principle of penalty-based UAI Charges. Additionally, the UAI Charges need to provide a sufficiently strong price signal to customers to plan and operate their systems in a fashion that avoids unauthorized increases on BPA's system.

BPA does not agree that it has acted in an arbitrary, capricious, or discriminatory manner as alleged by some parties. BPA's decisions are supported by the evidence in the record and are well reasoned and analyzed.

<u>Decision</u>

BPA has the authority to impose UAI Charges that are not strictly cost based.

<u>Issue 2</u>

Whether the use of California ISO price indexes is appropriate for the UAI Charges.

<u>Parties' Positions</u>

PPC opposes the use of California ISO Spinning Capacity Reserve and Supplemental Energy indexes for the UAI Charges for demand and energy, arguing that the ISO is demonstrably unreliable. PPC Brief, WP-02-B-PP-01, at 34-35; PPC Ex. Brief, WP-02-R-PP-01, at 7-8; Opatrny *et al*., WP-02-E-PP-02, at 20-22. PPC contends that the California ISO market indexes are flawed. PPC Brief, WP-02-B-PP-01, at 34-35; PPC Ex. Brief, WP-02-R-PP-01, at 7-8; Opatrny *et al*., WP-02-E-PP-02, at 20-22. PPC favors the use of DJ Mid-C price indexes in the determination of the UAI Charge for energy. PPC Brief, WP-02-B-PP-01, at 37-38; PPC Ex. Brief, WP-02-R-PP-01, at 8; Opatrny *et al*., WP-02-E-PP-02, at 22-23.

SUB also disagrees with BPA's proposed use of the California ISO charges for ancillary services as the basis for Unauthorized Charges. SUB Brief, WP-02-B-SP-01, at 7-8; SUB Ex. Brief, WP-02-R-SP-01, at 9-10. SUB notes its position is detailed in its direct testimony. SUB Brief, WP-02-B-SP-01, at 7; Nelson, WP-02-E-SP-01, at 4-8.

OURCA does not specifically address the use of California ISO indexes for the UAI Charges, but "adopts and joins" the positions stated in PPC's briefs with regard to the UAI Charges. OURCA Brief, WP-02-B-OU-01, at 7; OURCA Ex. Brief, WP-02-R-OU-01, at 6.

PGP supports the use of market price indexes for the UAI Charges. Knitter and Peters, WP-02-E-PG-01, at 6. However, PGP does not express support for or opposition to the use of any specific market indexes.

BPA's Position

BPA proposed incorporating the California ISO Spinning Capacity Reserve price indexes for the UAI Charges for demand. Keep *et al*., WP-02-E-BPA-17, at 15-17. BPA also proposed the use of California ISO Supplemental Energy price indexes, in conjunction with DJ Mid-C price indexes, in its determination of UAI Charges for energy. Keep *et al.,* WP-02-E-BPA-17, at 14-18. BPA stated that omission of the California ISO indexes would, at times, create undue cost exposure to BPA and would not be a sufficient deterrent against such overruns. Keep *et al.*, WP-02-E-BPA-43, at 25-26, 30-31; Tr. 1212-14.

While BPA acknowledges current market imperfections at the ISO, Tr. 1206; Keep *et al*., WP-02-E-BPA-43, at 31; these imperfections do not undermine the California market's relevance to BPA's cost exposure. Keep *et al*., WP-02-E-BPA-43, at 31; Tr. 1212. The specific forces that drive ISO price levels during any specific period are less relevant than the price levels themselves; it is the price levels, irrespective of their underlying determinants, that define BPA's cost exposure to unauthorized increases in demand. Keep *et al*., WP-02-E-BPA-43, at 31; Tr. 1206-07. The inclusion of California ISO price indexes in BPA's UAI Charge methodology is appropriate because, although the California ISO is not based in the Northwest, those price indexes are an indicator of BPA's cost exposure because of the very nature of the west coast markets. *Id*.; Keep *et al*., WP-02-E-BPA-43, at 33.

Evaluation of Positions

In direct testimony, BPA stated two reasons for including the ISO Supplemental Energy price indexes in its proposed design of the UAI Charge for energy. First, because ISO Supplemental Energy is traded on an hour-ahead basis, the ISO Supplemental Energy price index among all indexes most closely approximates the real-time circumstance that BPA faces when it must provide service to an unauthorized increase. Keep *et al*., WP-02-E-BPA-17, at 18. Second, there is more certainty around the availability of this index than the CalPX price indexes. *Id.* BPA proposed inclusion of the ISO Spinning Capacity Reserve price index because, during certain high cost periods, the minimum UAI Charges for demand would understate the true costs of serving demand overruns and would not provide a sufficient deterrent against unauthorized increases in demand. Keep *et al*., WP-02-E-BPA-43, at 30-31. The incorporation of California ISO indexes for the demand and energy UAI Charges recognizes that BPA and the Northwest are part of the larger west coast markets, and the California markets are relevant to BPA's cost exposure. *Id.*; Tr. 1206-07, 1212.

PPC cites the California ISO's *Report on Redesign of California Real-Time Energy And Ancillary Services Markets* in asserting that there are market imperfections in the California ISO markets. Opatrny *et al.,* WP-02-E-PP-02, at 20. PPC also cites an additional California ISO Report, *Second Report on Market Issues in the California Power Exchange Energy Markets,* March 1999, which documents FERC's recognition of the need for price controls in the California ISO ancillary services markets. PPC Brief, WP-02-B-PP-01, at 34-35. PPC also documents FERC's November 1999 extension of price cap authority for an additional year for the California ISO markets to allow for market redesign. *Id.* at 35.

SUB argues that BPA should not use California ISO ancillary services market indexes to price unauthorized increases in demand, because of the California ISO's own acknowledgement that its ancillary markets are not behaving as expected, and because of market power issues associated with the California ISO ancillary services markets. Nelson, WP-02-E-SP-01, at 5. SUB asserts that "BPA is in error when it states that it is appropriate for BPA to use California ISO prices in its UAI charges for demand and energy." SUB Ex. Brief, WP-02-R-SP-01, at 10. SUB cites the California ISO's *Annual Report on Market Issues and Performance,* June 6, 1999. Nelson, WP-02-E-SP-01, at 4-5. SUB also cites this California ISO report in opposing the use of California ISO Supplemental Energy price indexes for UAI Charges for energy. *Id*. at 7. SUB points out that BPA's system load profile, with firm obligations that are winter peaking, differs from the summer peaking load profile of Southwest suppliers. SUB Brief, WP-02-B-SP-01, at 7-8. SUB argues that these regional differences in firm obligations place BPA in the "awkward position of basing UAI Charges on an ancillary services market in which it may be the only supplier." *Id*. SUB notes BPA's acknowledgement that "pricing at the ISO is highest in late summer and BPA's Loads and Resources Study shows BPA has a surplus of power during that time." SUB Ex. Brief, WP-02-R-SP-01, at 10. SUB contends that it is "inappropriate for BPA to implement charges that are subject to market power, especially in periods where BPA has a surplus of power and market prices are high." *Id.* SUB concludes that BPA should base its UAI Charges for demand similar to Southwestern Power Administration's (SWPA) penalty charges, at three times the fixed monthly demand charge. SUB Brief, WP-02-B-SP-01, at 7-8; Nelson, WP-02-E-SP-01, at 5-6. SUB cites the impacts of transmission congestion on the California ISO Supplemental Energy prices in asserting that BPA should use only the DJ Mid-C indexes for its UAI Charges for energy. *Id.* at 7-8.

PPC and SUB both cite to reports that purportedly demonstrate the imperfections of the California ISO. These reports have no evidentiary weight and have not been entered into evidence by any party in this section 7(i) proceeding. When BPA's witnesses were cross-examined regarding their knowledge of the purported imperfections that exist in the California ISO, BPA's witnesses acknowledged some familiarity with these market imperfections in cross-examination, Tr. 1206-07, although PPC asserts that BPA witnesses, in fact, "are unfamiliar with the California ISO market . . ." PPC Brief, WP-02-B-PP-1, at 37.

PPC's argument concerning market imperfections in the California ISO is not persuasive and does not establish an evidentiary basis upon which BPA is willing to reject its use of the California ISO. BPA witnesses testified that BPA is part of a larger west coast system and that the California markets are relevant to BPA. Tr. 1206-07. To the extent the California market affects BPA, the magnitude of prices within that market is relevant to BPA even if at any point in time it may be due to some market imperfections. *Id*. Furthermore, use of the California ISO is reasonable and appropriate, because fixed charges are inadequate to serve as a deterrent against unauthorized increases in the current market. Tr. 1214. Experience with the market has indicated that a single price may not necessarily be as strong a disincentive as believed when it is set, particularly when it is to be in effect for five years. *Id*. This consideration supports the need, first of all, for some index-based component for the UAI Charge for demand. Keep *et al.*, WP-02-E-BPA-43, at 30-31. The California ISO is the only west coast market for demand services and, among the California ISO ancillary services products, the hourly Spinning Capacity Reserve prices most closely approximate the kind of service BPA must provide to an unauthorized increase in demand. Further, the DJ Mid-C price indexes, while appropriate for inclusion in the UAI Charge methodology as a PNW index, historically have not even attained to BPA's proposed minimum UAI Charge for energy of 100 mills/kWh. Wholesale Power Rate Development Study Documentation, Volume 2, WP-02-E-BPA-05B, at 90. This is due in part to the diurnal nature of the DJ Mid-C indexes, which will tend to mask higher hourly energy values at times. An hourly index, again, is necessary to provide some comparability with the real-time circumstance confronting BPA when serving an unauthorized increase. Keep *et al.*, WP-02-E-BPA-17, at 18. Given the absence of a PNW hourly price index for energy, it is appropriate for the UAI Charges for energy to incorporate an hourly index for energy at some market accessible by Northwest parties.

PPC's testimony and initial brief both indicate that, in fact, the California ISO is conducting a redesign of its markets to address the market imperfections. Opatrny *et al.*, WP-02-E-PP-02, at 21; PPC Brief, WP-02-B-PP-01, at 35. PPC also states that there is no evidence that the redesigned markets will function any better than the current California ISO markets. Opatrny *et al.,* WP-02-E-PP-02, at 21-22. However, the appropriateness of the California ISO indexes need not rest on the success of the California ISO's efforts to resolve the market imperfections that have characterized its early history. The ultimate price levels themselves are more relevant than their underlying determinants in defining BPA's cost exposure. Keep *et al.*, WP-02-E-BPA-43, at 31; Tr. 1206-07. Periods of high prices in California would potentially expose BPA to high opportunity costs or, under some scenarios, high purchase costs associated with providing service to an unauthorized increase, irrespective of the underlying reasons. Keep *et al.*, WP-02-E-BPA-43, at 25. It is also the case that such a period of high prices, whether driven by market impurities or not, would feature the greatest opportunities for customers to profit by arbitraging unauthorized increases if the design of UAI Charges does not incorporate these indexes. Tr. 1214.

In arguing that a forecast BPA power surplus invalidates the use of California ISO indexes during periods of high market prices, SUB Brief, WP-02-B-SP-01, at 7-8, SUB Ex. Brief, WP-02-R-SP-01, at 9-10, SUB ignores the potential incentives during such periods for arbitraging unauthorized increases into the California markets. SUB's reliance on the shape of BPA's forecast surplus in arguing against the use of the California ISO indexes further ignores the central intent of the UAI Charges, which is to ensure that there is always a penalty, or deterrent, against placing unauthorized increases on BPA's system. Tr. 1214. Inclusion of the California ISO indexes in the UAI Charge methodology is necessary to preserve that deterrent, as well as protecting BPA against undue costs associated with customers placing unauthorized increases on BPA's system. Keep *et al.,* WP-02-E-BPA-43, at 25; Tr. 1212.

Finally, in supporting its arguments against the inclusion of the California ISO indexes, SUB presents five points in its brief on exceptions that collectively cite a California ISO report; BPA's rebuttal testimony statements on the seasonality of California ISO prices and imperfections in the California markets; Keep *et al.*, WP-02-E-BPA-43, at 30-31; BPA's Loads and Resources Study; and the qualifications of BPA's witnesses sponsoring the UAI Charge testimony. SUB Ex. Brief, WP-02-R-SP-01, at 9-10. SUB gives no explanation of the meaning for the five enumerated points. BPA is unable to ascertain their meaning and, therefore, they fail to support a conclusion one way or the other regarding the appropriateness of BPA's proposed incorporation of the California ISO indexes in its UAI Charge framework. In summary, SUB has failed to adequately support its arguments against the inclusion of the California ISO indexes.

PPC argues that because the Mid-C market hub is the most reflective of costs and market values in the PNW (and because BPA uses the Mid-C hub for cost classification between demand and energy charges and seasonal differentiation and diurnal differentiation, and the fact BPA does more transactions at Mid-C than through the California ISO), it should be used in establishing the costs to BPA when imposing UAI Charges. PPC Brief, WP-02-B-PP-01, at 37-38; PPC Ex. Brief, WP-02-R-PP-01, at 8. In its direct testimony, PPC argued for reliance only on DJ Mid-C indexes by citing statements in a data response by BPA staff sponsoring the MCA. This BPA data response states that "the Mid-C trading hub was selected because of the available hubs in this analysis, Mid-C is the most representative of the relevant power prices in the PNW." Opatrny *et al*., WP-02-E-PP-02, at 22-23, citing Response to Data Request PP-BPA:082. BPA's MCA witnesses were correct in their response. Tr. 1212. However, the context for their response was the design of standard rates for requirements service under BPA's core power products, and that response cannot be generalized to charges for service beyond subscribed product purchases. *Id.*; Keep *et al*., WP-02-E-BPA-43, at 25. When BPA must provide service to an unauthorized increase, its cost exposure at times is best defined by prices in the California markets. *Id.*; Tr. 1206-07, 1212. Further, the California indexes may be necessary at certain times to set the UAI Charges at a level that deters customers from exceeding their contractual entitlements to place loads on BPA's system. Keep *et al.*, WP-02-E-BPA-43, at 25-26.

In arguing for exclusive use of Mid-C indexes, PPC also notes that BPA conducts a much higher volume of transactions at the Mid-C hub than it does in the California ISO markets. PPC Brief, WP-02-B-PP-01, at 37. BPA staff acknowledged that BPA conducts a far greater volume of transactions at the Mid-C hub than at the California ISO, while qualifying that the relative mix of transactions could change in the future. Tr. 1209-10. In spite of PPC's observations, the appropriateness of a particular index for purposes of the UAI Charges does not rest on the number or volume of transactions represented by that index. What is more relevant is the circumstances of those transactions. In the case of UAI Charges, the California ISO indexes reflect hour-ahead transactions that most closely resemble the real-time basis of service to demand and energy overruns by BPA's customers. Keep *et al.*, WP-02-E-BPA-17, at 18. By definition, BPA's transactions at Mid-C preclude real-time or even hour-ahead transactions; rather, they would be comprised of a mix of day-ahead transactions and transactions encompassing longer periods, as long as several years. Therefore, the number or volume of transactions at a particular hub has little relevance to the appropriateness of the associated price index(es) for use in the UAI Charges.

The California ISO Supplemental Energy and Spinning Reserve Capacity price indexes, aside from reflecting hour-ahead transactions that among available indexes most closely approximate the real-time nature of service to unauthorized increases, are for the common commodities, specifically energy and capacity, for which BPA is developing the UAI Charges. Despite the market imperfections that drive California ISO prices at times, their inclusion in the UAI Charge methodology is both reasonable and necessary in light of BPA's cost exposure, Keep *et al.*, WP-02-E-BPA-43, at 25; and BPA's need for a deterrent against demand and energy overruns placed on BPA's system. *Id*. at 25-26; Tr. 1213-14.

Decision

It is appropriate for BPA to use California ISO price indexes in its UAI Charges for demand and energy.

Issue 3

Whether the UAI Charges for energy and demand should be based upon market price indexes for the precise period when an unauthorized increase occurs.

Parties' Positions

PPC argues that BPA's proposed design of UAI Charges for demand and energy is flawed because "they are not based upon the market price at the time of the unauthorized increase." PPC Brief, WP-02-B-PP-01, at 35. In direct testimony, PPC stated its opposition to the use of market prices for the UAI Charges, while suggesting that BPA, at a minimum, base the charges on "the costs incurred at the time when the unauthorized increase occurs" rather than the highest prices realized in the Northwest and California markets for the month. Opatrny *et al.*, WP-02-E-PP-02, at 18-19. PPC argues that assuming the California ISO ancillary service market is robust, BPA has laid an inadequate foundation for the UAI Charge as a penalty charge. PPC Brief, WP-02-B-PP-01, at 35. PPC asserts that BPA's design of the "penalty charge" is apparently ignorant of FERC precedent defining penalty charges. *Id.* In its brief on exceptions, PPC asserts that the UAI charges were "designed without consideration of FERC precedent regarding appropriate penalty charges for ancillary services . . ." PPC Ex. Brief, WP-02-R-PP-01, at 7.

SUB proposes that the UAI Charges for demand be fixed at three times the applicable standard demand charge for the month. Nelson, WP-02-E-SP-01, at 5; SUB Brief, WP-02-B-SP-01, at 8. SUB proposes that the UAI Charges for energy be tied to "the cost of providing [unauthorized increase] service over the period" in which the unauthorized increase occurred, rather than on the highest market price index during a billing month. Nelson, WP-02-E-SP-01, at 7; SUB Brief, WP-02-B-SP-01, at 8. SUB supports a "pass-through-cost basis" in which the UAI Charges for demand and energy would apply only in those instances when FBS resources, both firm and nonfirm, are insufficient to meet demand or energy overruns; SUB contends that standard demand and energy charges should apply when FBS resources are sufficient to meet overruns. Nelson, WP-02-E-SP-01, at 5-6, 8.

OURCA does not specifically address this issue, but "adopts and joins" the positions stated in PPC's initial brief with regard to the UAI Charges. OURCA Brief, WP-02-B-OU-01, at 7.

BPA's Position

For energy overruns, BPA proposed that the UAI Charge for energy for a given month be the greatest of 100 mills/kWh, the highest DJ Mid-C price for the month, or the highest California ISO Supplemental Energy price for the month. Keep *et al.*, WP-02-E-BPA-17, at 17-18; Keep *et al.*, WP-02-E-BPA-43, at 24. BPA opposed a time-specific passthrough of costs tied to the market value of power at the time of an unauthorized increase. Keep *et al.*, WP-02-E-BPA-43, at 27-30.

BPA proposed that the UAI Charge for demand be the greater of three times the applicable standard demand charge for the month and the sum of the hourly ISO Spinning Reserve Capacity prices for all HLH during the month. Keep *et al.*, WP-02-E-BPA-17, at 17; Keep *et al.*, WP-02-E-BPA-43, at 24. By definition, BPA's proposed penalty for demand overruns would not be specifically driven by the highest hourly ISO Spinning Reserve Capacity price index for a given billing month; rather, the penalty would convert this hourly price index to a monthly index-based charge by summing all HLH prices for the month. Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 108.

BPA also opposes SUB's position that application of UAI Charges for demand and energy be contingent on BPA's resource sufficiency at the time of an unauthorized increase. Keep *et al.*, WP-02-E-BPA-43, at 28-29.

Evaluation of Positions

PPC characterizes BPA's proposed UAI Charges for demand and energy as flawed, because they are not based upon market prices at the time of the unauthorized increase. PPC Brief, WP-02-B-PP-01, at 35. In its direct testimony, PPC cites precedents in the gas industry and other power marketing administrations (*e.g.*, SWPA and Western Area Power Administration (WAPA)) to support time-specific passthrough cost bases for overrun penalties. Opatrny *et al.*, WP-02-E-PP-02, at 19.

SUB cites SWPA's P-98 B rate schedule in support of its proposal for a fixed penalty charge for demand that is applicable only when BPA resources are not sufficient to meet a customer's demand at the time of the overrun. Nelson, WP-02-E-SP-01, at 6; SUB Brief, WP-02-B-SP-01, at 8. SUB cites the WAPA-78 rate order to argue that the UAI Charges for energy should be based on the DJ Mid-C price indexes for the hour in which the unauthorized increase in energy occurred, and that only standard charges for energy be levied for those occurrences when BPA resources are sufficient to meet the energy overrun. Nelson, WP-02-E-SP-01, at 7-8; SUB Brief, WP-02-B-SP-01, at 8.

PPC's assertion that the UAI Charges for demand are not based upon the market price at the time of the increase, PPC Brief, WP-02-B-PP-01, at 35, is accurate. Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 108. For the index-driven penalty charges for demand, BPA proposed to sum the hourly California ISO Spinning Reserve Capacity prices for all HLH in a given billing month. BPA proposed that this index-based charge would be the effective charge if greater than three times the effective standard Demand Charge for the month. Keep *et al.*, WP-02-E-BPA-17, at 17; Keep *et al*., WP-02-E-BPA-43, at 24. This construct for the penalty charges for demand merely converts an hourly index for Spinning Reserve Capacity prices to the same monthly basis as the standard demand charges. Without this conversion, the maximum index-based penalty charge for demand overruns, as defined by the California ISO's current price cap for hourly Spinning Reserve Capacity, would be $0.75/kW/hr. In comparison to BPA's proposed average monthly demand charge of $2.00/kW/mo., this hourly charge is a price that is clearly too low to represent a deterrent against demand overruns. Further, while arguing that BPA's proposed design for UAI Charges for demand is flawed because the charges are not based on the market prices at the time of the demand overrun, PPC fails to acknowledge that BPA's service to a demand overrun for one hour constitutes a monthly service. In fact, the appropriate underlying assumption is that, similar to demand within a customer's contractual entitlement that is billed at the standard monthly charges, any service that BPA must provide to a demand overrun is a monthly service. BPA's standard demand charges apply to monthly service, and are billed on a $/kW-month basis. Keep *et al.*, WP-02-E-BPA-17, at 2-3. Therefore, in order to provide a meaningful index-based penalty, it is appropriate to sum all the hourly ISO Spinning Reserve Capacity prices for all HLH of the month.

In asserting flaws in the proposed design of the UAI Charges for demand and energy, PPC cites the cross-examination transcript, Tr. 1201, and the Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 108, in stating that the unauthorized increases in demand may be determined on an hourly basis, and unauthorized uses of energy may be determined on an hourly or diurnal basis. PPC Brief, WP-02-B-PP-01, at 35. As a point of clarification, Section II.V. of the GRSPs addresses the determination of the UAI Charges for demand and energy, Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 108-09, while the quantifications of demand and energy overruns are dependent on the product. Tr. 1198-99.

SUB suggests that BPA base its UAI Charges consistent with similar charges assessed by other Federal Power Marketing Agencies (PMAs). SUB Brief, WP-02-B-SP-01, at 8. The basis for penalty charges assessed by other PMAs has little applicability to BPA's situation; those entities have their own reasons for setting charges. Keep *et al*., WP-02-E-BPA-43, at 27. Unlike the two PMAs cited by PPC and SUB, BPA is obligated to meet the full net requirements of its wholesale utility customers. *Id.* Neither WAPA nor SWPA is similarly obligated; instead, they allocate Federal power from a finite pool of resources that can meet only a portion of their customers' firm requirements. *Id.* In contrast, BPA must stand ready to provide emergency supply service on an instantaneous basis, creating a cost exposure for BPA that other PMAs do not have. *Id.* at 27-28.

Both PPC and SUB argue that BPA's penalty charge should be consistent with FERC precedent regarding penalty charges. PPC Brief, WP-02-B-PP-01, at 35-37; PPC Ex. Brief, WP-02-R-PP-01, at 7; SUB Brief, WP-02-B-SP-01, at 8. PPC cites several FERC decisions regarding penalty charges: *New York State Electric & Gas Corp*., 79 FERC ¶ 61,371, 62,548-49 (1997); *Allegheny Power System*, 80 FERC ¶ 61, 045, 61,545-47 (1997), *New England Power Pool*, 83 FERC ¶ 61,045, 61,235 (1998); *Houston Lighting & Power Co*., 77 FERC ¶ 61,113, 61,439 n. 16 (1996); *Houston Lighting & Power Co*., 81 FERC ¶ 61,015 (1997); *Southwest Power Pool*, 86 FERC ¶ 61,090, 61,328, 61,330 (1999); *American Electric Power Company and Central and Southwest Corporation*, 85 FERC ¶ 61,201, 61,809, 61,824 (1998); and *Detroit*

Edison Company, 84 FERC ¶ 63,006, 65,043, 65,046 (1998). OURCA also cites *Allegheny Power System, Inc., et al*., 80 FERC ¶ 61,143, and *Detroit Edison Company*, 84 FERC ¶ 63,006 (1998). The decisions cited involve gas and electric utilities regulated by FERC. Many of these cases concern charges and rates concerning *pro forma* transmission tariffs. Unlike FERC's authority under the FPA or the Natural Gas Act to regulate such utilities, the statutory mandate accorded to FERC under the power marketing acts does not provide FERC such authority. *United States Department of Energy--Bonneville Power Admin.*, 13 FERC ¶ 61,157, at 61,340 (1980). Therefore, the cases cited by PPC have no precedential value; however, BPA may look to such cases for guidance.

BPA has had FERC approval to charge up to 100 mills/kWh for UAI Charges for over 20 years. *Id*. BPA is not persuaded by the cases cited by the parties to reject the foundation for BPA's UAI Charges. BPA is modifying these charges because as currently established they do not accurately reflect the costs to BPA caused by customers exceeding their contractual entitlement to take power. Keep *et al*., WP-02-E-BPA-17, at 15. The UAI Charge for energy in the 1996 rates was 100 mills/kWh. *Id*. The UAI Charge for demand in the 1996 rates was the effective standard Demand Charge, or $0.87/kW-month. *Id*. Since 1996, a robust wholesale power market has developed in which the 1996 UAI Charges simply do not perform as intended. *Id*. BPA has changed these charges to give BPA the flexibility to assess charges that reflect the volatility of the market in periods in which the market price for power exceeds the minimum UAI Charges for energy and demand. *Id*.

BPA's ability to plan its service obligations for the core Subscription products, as specified in the power sales contracts, and to control its costs depends on customers accurately specifying the demand and energy obligations that BPA must serve. Keep *et al.*, WP-02-E-BPA-17, at 17. The penalty aspect of BPA's UAI Charges is essential to deter customers from exceeding their contractual right to place load on BPA's system and to motivate customers to purchase the right product mix rather than to rely on unauthorized increases as an economic product choice. Keep *et al.*, WP-02-E-BPA-43, at 33. BPA does not want to undermine appropriate incentives for customers to purchase in advance products and services they need. Keep *et al*., WP-02-E-BPA-17, at 17; Keep *et al.*, WP-02-E-BPA-43, at 33; Tr. 1214. The application of charges tied to "market value" at the time of the unauthorized increase would undermine the deterrent nature of the charges. Keep *et al.*, WP-02-E-BPA-43, at 29. Limiting the penalty charges to the market price of power, as measured by some specified price index, on the hour or date of an unauthorized increase would increase the likelihood that the customer responsible for the overrun would experience no economic cost as a result of the overrun. *Id.* at 28-29. BPA recognized the developments in the open power markets in recent years in designing the UAI Charges to preclude an incentive for customers to arbitrage unauthorized increases and achieve profits during periods when market prices are high. Tr. 1213-14. Finally, the UAI Charges are intended to protect BPA from market cost exposure resulting from occurrences of unauthorized increases. Keep *et al.*, WP-02-E-BPA-17, at 16-17; Keep *et al.*, WP-02-E-BPA-43, at 29-31; Tr. 1212.

There is additional justification for not limiting the UAI Charges to the market value of power at the precise time of the unauthorized increase. With respect to UAI Charges for energy, energy overruns generally are determined on a monthly basis. Keep *et al.*, WP-02-E-BPA-43, at 29-30;

Tr. 1198-1199. The exception is the case of a Simple Partial customer that fails to deliver a resource on a given hour. *Id.* at 1199. Therefore, PPC's and SUB's proposal is not administratively feasible. Keep *et al.*, WP-02-E-BPA-43, at 29-30. Further, basing the UAI Charges for energy at the market value at the time of the overrun may underrecover BPA's cost of serving the overrun. There are cost impacts associated with unauthorized increases to BPA, even if BPA is not in the market. BPA could be forced to run water to generate in order to serve unauthorized increases during a less expensive period, resulting in BPA without adequate water to generate at a later time when market prices are higher. *Id.* at 28-29. While BPA's primary intent underlying its UAI Charges is to establish a penalty rate that provides a deterrent against demand and energy overruns, protection against such potential cost exposure is also an important component in the UAI Charges. Tr. 1212.

SUB's argument for application of standard demand and energy charges when BPA has sufficient resources to serve an unauthorized increase is without merit. First, identifying the hour or day when an unauthorized increase in energy occurs is generally not feasible. There is a problem of identifying during which hour or day an unauthorized increase in energy occurred when the determination involves a customer's total energy take during an entire billing month. Keep *et al.*, WP-02-E-BPA-43, at 28. Second, even in those instances when an unauthorized increase can be associated with a given hour, the cost implications to BPA are not confined to that hour, particularly if the system resources BPA expends to serve the unauthorized increase are unavailable during a subsequent higher cost period. *Id.* at 28-29. Third, SUB's argument completely ignores the need for the UAI Charges to provide a sufficient penalty to deter customers from placing demand and energy overruns on BPA's system. *Id.* at 29. To the contrary, in conjunction with other elements of SUB's proposal, a customer would know *a priori* that the most it would pay for unauthorized increases in energy at any point in time would be the DJ Mid-C index for that period and, in many cases, the customer would face only standard energy charges. *Id.* Similarly, a customer would know that the maximum charge for a demand overrun would be three times the standard demand rate, with a significant probability that it would face only the standard demand charge. SUB's proposal, in effect, would alter the design of the UAI Charges in a way that would make demand and energy overruns an economic alternative to customers, undermining their incentive to operate their systems in a fashion that avoids unauthorized increases and to make appropriate product purchases. *Id.* BPA rejects SUB's proposal that only standard demand and energy charges would apply when BPA has sufficient resources to serve unauthorized increase in demand or energy.

The need to preserve the penalty aspect of the UAI Charges and the need to maintain protection against cost exposure associated with energy overruns support basing the UAI Charges for energy on the highest market price index for the billing month (subject to the 100 mills/kWh minimum; see next Issue). BPA proposed the use of the monthly maximum DJ Mid-C price index and the monthly maximum California ISO Supplemental Energy price indexes in the design of its UAI Charges for energy. The same imperatives for a penalty component and protection against cost exposure govern the design of the UAI Charges for demand. The design of BPA's UAI Charges for demand is not tied to the market price at the time of a demand overrun; rather, the design simply converts the hourly California ISO Spinning Reserve Capacity price indexes to a monthly basis to correspond with the monthly service BPA provides to a demand overrun for any hour. Finally, the UAI Charges should apply in all cases when an unauthorized increase occurs.

Decision

The UAI Charges for energy and demand are not based upon market price indexes for the precise period when an unauthorized increase occurs.

Issue 4

Whether the UAI Charges for demand and energy should include a "floor."

Parties' Positions

PPC argues that the UAI Charge is objectionable for being asymmetrically based on the greater of a floor or a market. PPC asserts that if BPA may charge the market price for an unauthorized increase when the market prices are high, BPA should similarly charge a market price when those prices are low. PPC Brief, WP-02-B-PP-01, at 37. PPC asserted in direct testimony that the 100 mills/kWh floor charge for energy overruns should be eliminated. Opatrny *et al.*, WP-02-E-PP-02, at 23.

SUB proposes that the UAI Charges for demand be fixed at three times the applicable demand charges for a specific month. Nelson, WP-02-E-SP-01, at 5-6; SUB Brief, WP-02-B-SP-01, at 8. SUB essentially proposes to fix the UAI Charges for demand at BPA's proposed floor. SUB further proposes that the floor for the UAI Charges for energy be eliminated, and that BPA charge 100 mills/kWh only in the case where the DJ Mid-C Indexes cease to exist. Nelson, WP-02-E-SP-01; at 8; SUB Brief, WP-02-B-SP-01, at 8.

OURCA presents no specific proposal regarding the floor charges for demand and energy overruns. However, OURCA asserts that the UAI Charges should be eliminated or revised, and adopts and joins positions stated in the PPC Brief with respect to the UAI Charges. OURCA Brief, WP-02-B-OU-1, at 7.

BPA's Position

BPA proposed a minimum charge for unauthorized increases in demand equal to three times the applicable monthly demand charge. Keep *et al.*, WP-02-E-BPA-17, at 17; Keep *et al.*, WP-02-E-BPA-43, at 24. BPA proposed a minimum charge of 100 mills/kWh for the unauthorized increases in energy. Keep *et al.*, WP-02-E-BPA-17, at 17.

Evaluation of Positions

PPC asserts that BPA's UAI Charge design is asymmetrical given that it includes floor charges in conjunction with market-based charges. PPC Brief, WP-02-B-PP-01, at 37. PPC further argues that if BPA levies market-based charges during periods of high market prices, it should similarly charge market prices when those prices are low. *Id.* PPC argues that BPA should collect only the costs that it incurs. Opatrny *et al*., WP-02-E-PP-02, at 23. PPC asserts that BPA should not experience a windfall from unauthorized increases when market prices are low, and that if BPA relies upon market indexes for determining "the extent to which it is harmed, then a floor is unnecessary." *Id.*

SUB cites the SWPA's P-98 B rate schedule to support its proposal that the UAI Charge for demand should be fixed at three times the applicable monthly demand charge, a penalty charge that would be applicable only in those instances where BPA has insufficient resources to serve an unauthorized increase in demand. Nelson, WP-02-E-SP-01, at 5-6; SUB Brief, WP-02-B-SP-01, at 8. SUB cites the WAPA-78 rate order in arguing against the floor for the UAI Charges for energy. Nelson, WP-02-E-SP-01, at 7; SUB Brief, WP-02-B-SP-01, at 8.

PPC's arguments that BPA should collect only the costs that it incurs and SUB's arguments for a passthrough cost basis for the penalty charges ignore the need for a meaningful penalty component that deters customers from placing unauthorized increases on BPA's system. Keep *et al.*, WP-02-E-BPA-43, at 33. The UAI Charges are penalty charges. Tr. 1200. While protection against BPA's cost exposure is a consideration in the design of the UAI Charges, the penalty aspect in the charges is necessary to motivate customers to purchase products and services to ensure that they do not place loads on BPA beyond their contractual rights, and not to use unauthorized increases as an economic alternative to those products and services. Keep *et al.*, WP-02-E-BPA-17, at 17; Keep *et al.*, WP-02-E-BPA-43, at 28-29; Tr. 1213-14. BPA's ability to plan its service obligations for the core Subscription products and to control its costs depends on customers accurately specifying the obligations that BPA must serve, both demand and energy. Keep *et al.*, WP-02-E-BPA-17, at 17. Any occurrences of unauthorized increases undermine BPA's ability to plan its service obligations and control its costs. *Id.*

Further, the minimum charges may be necessary to ensure that the penalty charges are high enough to provide a meaningful deterrent. For instance, the historical data show that index-based charges for demand, had they been in place in February 1999, would have been $1.52/kW/mo., or less than BPA's proposed February PF Demand charge for the 2002 rates. Keep *et al.*, WP-02-E-BPA-17, at 16; Volume 2, Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05B, at 75. Similarly, the index-based UAI Charge for energy for January 1999 would have been 53 mills/kWh, less than the current fixed charge of 100 mills/kWh. Keep *et al.*, WP-02-E-BPA-17, at 16; Volume 2, Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05B, at 90. The minimum charges are necessary to ensure that the penalty component is in place during all periods sufficient to deter customers from placing energy and demand overruns on BPA's system.

The minimum UAI Charges for demand and energy ensure that some penalty will be in place for unauthorized increases in the unlikely event that the proposed indexes cease to exist and suitable successor indexes are unavailable. Keep *et al.*, WP-02-E-BPA-17, at 17.

SUB's proposal for standard charges to govern when BPA has sufficient resources to serve unauthorized increases undermines the deterrent elements of the UAI Charges, does not protect BPA from undue cost exposure, and is administratively impractical. Keep *et al.*, WP-02-E-BPA-43, at 28-29. (*See* previous Issue.)

Decision

BPA's floor components for the UAI Charges for demand and energy are necessary.

10.7 Excess Factoring Charges

BPA proposed two new penalty charges related to BPA's factoring service for core Subscription products. *See* Keep *et al*., WP-02-E-BPA-17, at 19. The term "factoring" refers to the service of shaping a given quantity of energy among either HLH or LLH of a period (*i.e*., day or month) to follow load. *Id*. Only when customer resources have hour-to-hour variability is there a possibility of receiving factoring service amounts which are less or greater than the entitlement amount. *Id*. Factoring service is a bundled component of Subscription core products for Full Service and Actual Partial Service. For purposes of administering the Actual Partial Service-Complex product, which involves serving customers with variable resources, a factoring benchmark test would be done in the billing process. *Id*.

In its initial brief, PPC argued that the Excess Factoring Charge "suffers from flaws which mirror the just-described flaws in the unauthorized increase charge." PPC incorporated its analysis of the UAI Charges into its argument on the Excess Factoring Charge regarding the lack of cost basis for the charge; use of the imperfect California ISO ancillary services market in lieu of a cost basis; the absence of foundation to support such a "penalty" charge; and the asymmetric design of the charge. BPA addresses each issue in turn. Because the PPC relies on the same arguments it made concerning the UAI Charges for purposes of addressing the Excess Factoring Charge, BPA finds it necessary to also reference its testimony regarding the UAI Charges where applicable.

Issue 1

Whether BPA lacks the authority to impose an Excess Factoring Charge that is not reflective of BPA's cost.

Parties' Positions

PPC incorporates its argument regarding the UAI Charges and similarly argues that the Excess Factoring Charge is not cost-based as required by BPA's statutes. PPC Brief, WP-02-B-PP-01, at 38. OURCA argues that BPA lacks the authority to impose penalties without some basis tied to the underlying service and the associated costs that BPA may incur. OURCA asserts that the charges should be eliminated or revised. OURCA Brief, WP-02-B-OU-01, at 7.

PPC reiterated its argument that the Excess Factoring Charge is not based on BPA's costs, as required by statute. They claim that BPA arbitrarily rejected this argument. PPC Ex. Brief, WP-02-R-PP-01, at 8.

OURCA also reiterates its argument that BPA does not have the authority to adopt the excess factoring penalties in the Draft ROD without some explanation of or link to the underlying service and the costs that BPA may incur. OURCA adopts and joins the position of the PPC as stated in PPC's brief on exceptions. OURCA Ex. Brief, WP-02-B-OU-01, at 6.

BPA's Position

The Excess Factoring Charge operates similarly to the UAI Charges, and is intended to be a penalty rather than a cost recovery mechanism. Keep *et al*., WP-02-E-BPA-43, at 34. It is a charge for use of more of a service than allowed in the product being purchased. *Id*. The Excess Factoring Charges are intended to be an incentive to get customers to use factoring services within their specified limits and, secondarily, to protect BPA from cost exposure in those instances where Excess Factoring does occur. *See* Keep *et al*., WP-02-E-BPA-17, at 21-22. Therefore, as in the case of Unauthorized Increase, the intent of the Excess Factoring Charge is to assure it does not appear to a customer that it would be more economical to exceed the product limits and pay the Excess Factoring Charges than to arrange up front for a product of a reserve nature. Tr. 1214.

Evaluation of Positions

PPC argues that the foundation for BPA's proposed Excess Factoring Charge is suspect, because it is not based on BPA's cost as required by statute. PPC Brief, WP-02-B-PP-01, at 37. OURCA similarly contends that BPA lacks authority to impose these penalties without some explanation of or link to the underlying service and the costs that BPA may incur. OURCA Brief, WP-02-B-OU-01, at 7. Neither party provided specific analysis to support the claim that BPA lacks authority to impose the Excess Factoring Charge. As already discussed with respect to the UAI Charges, BPA has the authority to impose non-cost based penalty charges. This is equally applicable to the imposition of the Excess Factoring Charges.

The UAI Charge provides a precedent to the Excess Factoring Charge. Since its inception in 1974, the UAI Charge has been developed to be a penalty and not a cost-based rate. *See* 1993 ROD, WP-93-A-02, at 169. FERC has recognized the Administrator's authority to impose an UAI Charge that is not cost-based. *United States Department of Energy--Bonneville Power Admin.*, 13 FERC ¶ 61,157, 61,340 (1980). FERC approved BPA's UAI Charge of 100 mills/kWh in the 1970s, when costs were less than 5 mills/kWh. 1993 ROD, WP-93-A-02, at 171. FERC predicated its approval on the fact that the UAI Charge was designed to modify customers' behavior. *Id*. FERC took notice of the fact that the charge was developed to assure that BPA's customers used their own resources first to meet their firm system load obligations. *Id*. As such, FERC noted that such a charge also ensures that the power BPA's customers marketed to others was truly excess resource capability. *Id*.

Similarly, BPA has determined the need for the Excess Factoring Charge as a penalty charge to discourage excess use of factoring. Keep *et al*., WP-02-E-BPA-43, at 36. When BPA is forced to provide factoring service beyond that specified by the products that the customer has purchased, that extra service can necessitate real-time adjustments that burden BPA's system and can have cost consequences to BPA. Keep *et al*., WP-02-E-BPA-17, at 21. This is especially true if a customer's excess factoring represents a shift from lower-cost periods of the day or month to higher-cost periods. *Id*. When Within-Day and Within-Month Excess Factoring has occurred, BPA has in effect provided a shaping service associated with the customer's resources rather than its load. *Id*. at 22-23. The Excess Factoring Charges are intended to be an incentive to get customers to use factoring services within their specific limits and, specifically, to protect BPA from cost exposure in those instances where Excess Factoring occurs. *Id*. at 22.

It is appropriate for the Excess Factoring Charge to provide a penalty rather than be tied to some cost basis. BPA adopts the principle of penalty-based Excess Factoring Charges. Additionally, the Excess Factoring Charges need to provide a sufficiently strong price signal to customers to plan and operate their systems in a fashion that avoids placing excess factoring on BPA's system.

BPA does not agree that it has acted in an arbitrary, capricious, or discriminatory manner as alleged by some parties. BPA's decisions are supported by the evidence in the record and are well reasoned and analyzed.

Decision

BPA has the authority to impose Excess Factoring Charges that are not reflective of BPA's costs.

Issue 2

Whether the use of California ISO price indexes is appropriate for the Excess Factoring Charges.

Parties' Positions

In its comments on the Excess Factoring Charge, PPC incorporates its argument regarding the use of California ISO Spinning Capacity Reserve and Supplemental Energy indexes for the UAI Charges, and similarly argues that the ISO is demonstrably unreliable as it pertains to the Excess Factoring Charge. PPC Brief, WP-02-B-PP-01, at 38.

The Market Access Coalition Group (MAC) supports PPC's testimony on the Excess Factoring Charge. MAC states: "As explained by Ms. Opatrny, BPA should base the ceiling charges for excess factoring on Mid-C energy index prices, not California ISO prices." MAC Brief, WP-02-B-MA-01, at 15.

OURCA states that the Unauthorized Increase and Excess Factoring charges should be revised or eliminated. OURCA Brief, WP-02-B-OU-01, at 7. OURCA adopts and joins the position of PPC as stated in their initial brief with regard to the UAI Charges and the Excess Factoring Charge. *Id*.

BPA's Position

While BPA agrees that DJ Mid-C indexes are appropriate for development of rates for requirements service, BPA does not agree that the availability of such indexes limits BPA's application of the ISO indexes for determining the Excess Factoring Charge. Keep *et al*., WP-02-E-BPA-43, at 35. The Excess Factoring Charge is intended to be a penalty charge that discourages excess use of factoring, and it should be calculated at a minimum to offset any financial gains that the customer could achieve. Keep *et al*., WP-02-E-BPA-43, at 36.

Evaluation of Positions

As with PPC's arguments regarding the UAI Charges, PPC similarly argues that Excess Factoring must be consistent with the theory that BPA should recover actual costs. PPC Brief, WP-02-B-PP-01, at 36. "In summary, the foundation for BPA's proposed UAI charge is suspect, for it is not based on BPA's cost as required by statute . . ." *Id*. at 37. MAC supports PPC and notes that "BPA should be charging the cost that it incurred for providing service, and therefore, the charge should reflect conditions when the excess factoring occurred." MAC Brief, WP-02-B-MA-01, at 15, quoting Opatrny, WP-02-E-PP-02, at 24. OURCA adopts and joins PPC's position. OURCA Brief, WP-02-B-OU-01, at 7. The parties contend that BPA should base the ceiling charges for excess factoring on Mid-C energy index prices, not California ISO prices. PPC Brief, WP-02-B-PP-01, at 38; MAC Brief, WP-02-B-MA-01, at 15.

For the same reasons given by BPA in support of the UAI Charges, the Excess Factoring Charge is a penalty rather than a cost recovery mechanism. Keep *et al.*, WP-02-E-BPA-43, at 34. BPA does not agree that the DJ Mid-C indexes should be used for determining the Excess Factoring Charge. *Id*. at 36. BPA's inclusion of ISO indexes in its Excess Factoring Charge recognizes that the markets drive its cost exposure, and there are times when this market-driven cost exposure is more closely tied to the California markets. *Id*. Also, since the Excess Factoring Charge, like the UAI Charges, is intended to be a penalty charge that discourages excess use of factoring, it should be calculated at a minimum to offset any financial gains that the customer could achieve. *Id*.; Tr. 1214.

MAC asserted that the within-day charges should be based on daily prices, not monthly prices. MAC Brief, WP-02-B-MA-01, at 15. However, BPA's within-day excess factoring charges are based on neither daily nor monthly prices. BPA is using hourly prices to calculate its within-day factoring charge. BPA uses "the maximum Within-Day difference" that occurs "during the month." Keep *et al.*, WP-02-E-BPA-17, at 22. Using the maximum difference found during the month assures that the penalty charge will provide a disincentive to customers to rely on Excess Factoring as a product. It is unclear to BPA, because of the manner in which PPC incorporated its UAI Charge analysis, whether timing is an issue with the Excess Factoring Charge. Nonetheless, in response to whether timing is an issue, BPA is implementing a reasonable method to base the Excess Factoring Charge as already explained.

PPC cites to reports that purportedly demonstrate the imperfections of the California ISO. PPC cites the California ISO's *Report on Redesign of California Real-Time Energy And Ancillary Services Markets* in asserting that there are market imperfections in the California ISO markets. Opatrny *et al*., WP-02-E-PP-02, at 20. PPC also cites an additional California ISO Report, *Second Report on Market Issues in the California Power Exchange Energy Markets*, March 1999, which documents FERC's recognition of the need for price controls in the California ISO ancillary services markets. PPC Brief, WP-02-B-PP-01, at 34-35. PPC also documents FERC's November 1999 extension of price cap authority for an additional year for the California ISO markets to allow for market redesign. *Id*. at 35. These reports have no evidentiary weight, and have not been entered into evidence by any party in this section 7(i) proceeding.

PPC's argument concerning market imperfections in the California ISO is not persuasive and does not establish an evidentiary basis upon which BPA is willing to reject its use of the California ISO. While BPA acknowledges current market imperfections at the ISO, Tr. 1206; Keep *et al*., WP-02-E-BPA-43, at 31; these imperfections do not undermine the California market's relevance to BPA's cost exposure. Keep *et al*., WP-02-E-BPA-43, at 31; Tr. 1212. BPA witnesses testified that BPA is part of a larger west coast system, and that the California markets are relevant to BPA. Keep *et al*., WP-02-E-BPA-43, at 30; Tr. 1206-07. To the extent the California market affects BPA, the magnitude of prices within that market is relevant to BPA even if at any point in time it may be due to some market imperfections. *Id*. Furthermore, use of the California ISO is reasonable and appropriate, because fixed charges may not necessarily be as strong a disincentive over a period of time, particularly if such a charge is to be in effect for five years. Tr. 1214. And again, like the use of the California ISO in determining the UAI Charges, BPA intends the Excess Factoring Charge to be a penalty. Keep *et al.*, WP-02-E-BPA-43, at 36.

Likewise, BPA recognizes the need for an hourly index to set a charge for excess within-day factoring. The use of an hourly index to determine the highest Within-Day differences is a measure of the potential cost exposure to BPA associated with this excess factoring service. Keep *et al*., WP-02-E-BPA-17, at 22. The derivation of index driven charges for within-day Excess Factoring (which are to be compared to a defined minimum charge) are, by definition, reliant on some hourly index. Keep *et al*., WP-02-E-BPA-43, at 31. There is no PNW hourly price index currently available for performing these derivations. *Id*. Given the absence of a PNW hourly price index for energy, it is appropriate for the Within-Day Excess Factoring Charge to incorporate an hourly index for energy at some market accessible by Northwest parties.

The discovery and correction of market flaws in the California ISO does not disqualify it as the best available public index for products which are similar in nature to those which must be used to serve Excess Factoring usage. PPC's testimony and initial brief both indicate that, in fact, the California ISO is conducting a redesign of its markets to address the market imperfections. Opatrny *et al.*, WP-02-E-PP-02, at 21; PPC Brief, WP-02-B-PP-01, at 35. PPC also states that there is no evidence that the redesigned markets will function any better than the current California ISO markets. Opatrny *et al.*, WP-02-E-PP-02, at 21-22. However, as was discussed regarding the UAI Charges, the appropriateness of the California ISO indexes need not rest on the success of the California ISO's efforts to resolve the market imperfections that have characterized its early history. The ultimate price levels themselves are more relevant than their underlying determinants in defining BPA's cost exposure. Keep *et al.*, WP-02-E-BPA-43, at 31; Tr. 1206-07. Periods of high prices in California would potentially expose BPA to high opportunity costs or, under some scenarios, high purchase costs associated with providing service to an unauthorized increase, irrespective of the underlying reasons. Keep *et al.*, WP-02-E-BPA-43, at 25. It is also the case that such a period of high prices, whether driven by market impurities or not, would feature the greatest opportunities for customers to profit by arbitraging unauthorized increases if the design of Excess Factoring Charges does not incorporate these indexes. Tr. 1214.

In its arguments against the UAI Charge, PPC argues that because the Mid-C market hub is the most reflective of costs and market values in the PNW (and because BPA uses the Mid-C hub for cost classification between demand and energy charges and seasonal differentiation and diurnal differentiation, and the fact BPA does more transactions at Mid-C than the California ISO) it should be used in establishing the costs to BPA when it imposes an UAI charge. PPC Brief, WP-02-B-PP-01, at 37-38. In its direct testimony, PPC argued for reliance only on DJ Mid-C indexes by citing statements in a data response by BPA staff sponsoring the MCA. This BPA data response states that "the Mid-C trading hub was selected because of the available hubs in this analysis, Mid-C is the most representative of the relevant power prices in the PNW." Opatrny *et al*., WP-02-E-PP-02, at 22-23; Response to Data Request PP-BPA:082. BPA's Marginal Cost Analysis witnesses were correct in their response. Tr. 1212. However, the context for their response was the design of standard rates for requirements service under BPA's core power products, and that response cannot be generalized to charges for service beyond subscribed product purchases. *Id.*; Keep *et al*., WP-02-E-BPA-43, at 25. When BPA must provide service to an excess factoring occurrence, its cost exposure at times is best defined by prices in the California markets. *Id.*; Tr. 1206-07, 1212. Further, the California indexes may be necessary at certain times to set the Excess Factoring Charges at a level that deters customers from exceeding their contractual entitlements to place loads on BPA's system. Keep *et al.*, WP-02-E-BPA-43, at 25-26.

In arguing for exclusive use of Mid-C indexes, PPC also notes that BPA conducts a much higher volume of transactions at the Mid-C hub than it does in the California ISO markets. PPC Brief, WP-02-B-PP-01, at 37. PPC's argument is not persuasive. BPA evaluated this argument with respect to the UAI Charges, and finds that evaluation equally applicable here. Both sets of charges are penalty charges intended to be a disincentive to relying on these charges as stand-ready products. BPA acknowledged that BPA conducts a far greater volume of transactions at the Mid-C hub than at the California ISO, while qualifying that the relative mix of transactions could change in the future. Tr. 1209-10. In spite of PPC's observations, the appropriateness of a particular index for purposes of the Excess Factoring Charges does not rest on the number or volume of transactions represented by that index.

BPA's inclusion of ISO indexes in its Excess Factoring Charge recognizes that the markets drive its cost exposure, and there are times when this market-driven cost exposure is more closely tied to the California markets. Also, since the Excess Factoring Charge is intended to be a penalty charge that discourages excess use of factoring, it should be calculated at a minimum to offset any financial gains that the customer could achieve. BPA does not want to price an excess use charge such that customers use it to make a profit elsewhere. Keep *et al.*, WP-02-E-BPA-43, at 36.

Decision

BPA adopts the use of California ISO price indexes in its Excess Factoring Charge.

Issue 3

Whether the Within-Day and Within-Month Excess Factoring Charges should be symmetrical by eliminating the floor.

Parties' Positions

PPC incorporates its analysis that the UAI Charge is objectionable for being asymmetrically based on the greater of a floor or a market, and argues that the Excess Factoring Charge is similarly asymmetrical. PPC Brief, WP-02-B-PP-01, at 38.

BPA's Position

The minimum charge is five mills/kWh. This will be the minimum charge for both HLH and LLH Within-Month Excess Factoring energy. Keep *et al.*, WP-02-E-BPA-17, at 23. Also, this amount (5 mills) sets a floor to ensure that there is some minimum penalty for Within-Day Factoring. *Id.* at 22.

Evaluation of Positions

BPA notes that prudent reliability is best served by an unambiguous and substantial price signal associated with exceeding product service, such that customers will have an incentive to purchase the appropriate products in advance. Keep *et al.*, WP-02-E-BPA-17, at 22; Tr. 1214. It is BPA's intent to establish the appropriate penalties such that parties will not ignore the products BPA makes available to support customer resources and avoid excess factoring and unauthorized increases. *Id*.

In its analysis of the UAI Charge, PPC asserts that BPA's UAI Charge design is asymmetrical given that it includes floor charges in conjunction with market-based charges. PPC Brief, WP-02-B-PP-01, at 37. PPC further argues that if BPA levies market-based charges during periods of high market prices, it should similarly charge market prices when those prices are low. *Id.* PPC witnesses argue that BPA should collect only the costs that it incurs. Opatrny *et al*., WP-02-E-PP-02, at 23. PPC asserts that BPA should not realize a windfall from unauthorized increases when market prices are low: "if BPA is going to rely on market indexes for determining the extent to which it is harmed, then a floor is unnecessary." *Id.*

In response to the PPC's analysis as applied to the Excess Factoring Charge, BPA maintains that the five mills/kWh floor is appropriate to assure that there will always be some penalty to deter customers from placing an excess factoring burden on BPA's system. Keep *et al.*, WP-02-E-BPA-17, at 23. BPA incorporates the following arguments regarding UAI Charges since they are applicable to excess factoring as well. PPC's argument that BPA should collect only the costs that it incurs ignores the need for a meaningful penalty component that deters customers from placing unauthorized increases on BPA's system. Keep *et al.*, WP-02-E-BPA-43, at 33. Similarly, the Excess Factoring Charges are intended to be an incentive to get customers to use factoring services within their specified limits and, secondarily, to protect BPA from cost exposure in those instances where Excess Factoring does occur.

Keep *et al.,* WP-02-E-BPA-17, at 22. The Excess Factoring Charge operates similar to the UAI Charge, and is intended to be a penalty rather than a cost recovery mechanism. Keep *et al.,* WP-02-E-BPA-43, at 34. While protection against BPA's cost exposure is a consideration in the design of the UAI Charges and the Excess Factoring Charge, the penalty aspect in the charges is necessary to motivate customers to purchase the products and services to ensure that they do not place loads on BPA beyond their contractual rights, and not to use unauthorized increases or excess factoring services as an economical alternative to those products and services. Keep *et al.,* WP-02-E-BPA-17, at 17; Keep *et al.,* WP-02-E-BPA-43, at 28-29; Tr. 1213-14. BPA's ability to plan its service obligations for the core Subscription products and to control its costs depends on customers accurately specifying the obligations that BPA must serve. Keep *et al.*, WP-02-E-BPA-17, at 17. Therefore, just as described in the case for the UAI Charges, any occurrences of excess factoring undermine BPA's ability to plan its service obligations and control its costs. In addition, the five mills/kWh floor is appropriate to ensure that there is some minimum penalty for Within-Day Excess Factoring in the event that the hourly index does not yield a higher charge or, although less likely, that at some point during the rate period there is no suitable hourly index available. Keep *et al.,* WP-02-E-BPA-17, at 22. In initial testimony concerning Within-Month Excess Factoring, BPA stated: "The five mills/kWh floor is appropriate to assure that there will always be some penalty to deter customers from placing this Excess Factoring burden on BPA's system." *Id.* at 23.

Further, the minimum charges may be necessary to ensure that the penalty charges are high enough to provide a meaningful deterrent. Though BPA did not find any historical instances where the floor charge would have been applied, the minimum charges are necessary to ensure that the penalty component is in place during all periods sufficient to deter customers from placing excess factoring on BPA's system. *Id*.

<u>Decision</u>

BPA's floor component for the Excess Factoring Charge is necessary to preserve the deterrent nature of the charges, and to preserve customer incentives to plan and operate their systems in a fashion that avoids the occurrences of excess factoring.

<u>Issue 4</u>

Whether in the rate case BPA should create an exemption from Excess Factoring Charges for excess factoring events related to customer forecast error.

<u>Parties' Positions</u>

SUB argues that it is wrong to apply Excess Factoring Charges in the event of customer load variations, because II.B.1 of the Subscription ROD states that load variations are part of a core, cost-based product. SUB Brief, WP-02-B-SP-01, at 9. SUB states that "BPA's suggestion to purchase a FPS product to meet load forecast error is also inconsistent with the Subscription ROD." *Id*. SUB further contends that "BPA's rate design is flawed in that it does not comport with the Subscription ROD guidelines." *Id*. SUB contends that "[b]ecause the Federal Register Notice states that issues, such as the definition of a Core Subscription Product, decided in the

Subscription ROD are not able to be revisited in this case and the fact that BPA has created a product which does not comport with the Subscription ROD, variation in load is a rate case issue." SUB Ex. Brief, WP-02-R-SP-01, at 11.

BPA's Position

BPA offered an FPS-priced product to meet load forecast error. Case-specific FPS-priced resource variability products could be negotiated to replace Excess Factoring Charges for forecast error. Keep *et al.*, WP-02-E-BPA-43, at 35. SUB contends that this FPS-priced product is also in conflict with section II.B.1 of the Subscription ROD. This is a new issue raised in answer to BPA's FPS offering.

Evaluation of Positions

SUB argues that BPA's rate design is flawed because of an alleged inconsistency between Section II.B.1 of the Subscription ROD and BPA's suggestion that customers purchase an FPS product to meet load forecast error. SUB Brief, WP-02-B-SP-01, at 9. SUB points to BPA's rebuttal testimony as evidence of this flaw, where BPA states: "Because BPA will be unable to distinguish whether excess factoring was due to forecast error versus operational or commercial choices made by the utility, it is possible that forecast error could incur Excess Factoring Charges." *Id*., quoting Keep *et al*., WP-02-E-BPA-43, at 35. SUB's brief criticizes the factoring service in the Actual Partial Service-Complex product, not the proposed Excess Factoring Charge. *Id*. SUB argues that BPA has created a product which does not comport with the Subscription ROD, and thus variation in load is a rate case issue. SUB Ex. Brief, WP-02-R-SP-01, at 11. SUB notes that in its testimony it suggested modifying the proposed Excess Factoring Rate in an attempt to align the rate with the Subscription ROD. *Id*.

In its brief on exceptions, SUB continues to mischaracterize Load Forecast Error as a load variation rather than as an inability to accurately forecast load. BPA does not agree with SUB's characterization. SUB has offered no reason for BPA to alter its position. SUB's argument regarding the Excess Factoring Charge is intertwined with BPA's power product development. In its comments regarding the factoring service, SUB expresses its confusion over the product and questions whether the rate can be successfully implemented as a result of errors SUB claims have been made in attempts to clarify application of the rates associated with factoring. *Id*. SUB alleges there is low customer confidence in the product and raises the issue of whether the rate design for factoring and associated products has been proposed according to "sound business principles." *Id*. The appropriateness of the excess factoring service to events involving customer load variations, however, is a function of product design, and therefore is not a rate case issue.

BPA testified that factoring service is a bundled component of Subscription core products for Full Service and Actual Partial Service. Keep *et al*., WP-02-E-BPA-17, at 19. By definition, a customer without resources or a customer whose resources are delivered flat will take exactly the amount of factoring service that they are entitled to. *Id*. In comparison, BPA testified further that for purposes of administering the Actual Partial Service-Complex product, which involves serving customers with variable resources, a factoring benchmark test would be done in the billing process. *Id*. Factoring, subject to the benchmark process, may be purchased as an add-on to a Firm Block core product. *Id*. SUB mischaracterizes the way customer load variations would interact with the product provisions for purposes of determining excess factoring usage. SUB's witness argued against the factoring service because "BPA's proposed factoring service is an unbundled service from what BPA is currently offering and would increase the cost of doing business with BPA in purchasing an Actual Partial Service product." Nelson, WP-02-E-SP-01, at 9. SUB noted that BPA's PF service currently follows both customers' loads and customers' resources. *Id*. SUB's mischaracterization of load forecast error as load variation is an inappropriate attempt to derail the unbundled factoring service.

BPA testified that the rates applicable to BPA's core Subscription products assume that BPA undertakes the cost of factoring energy to meet the shape of customer loads, but not the various potential shapes of customer resource generation. Keep *et al*., WP-02-E-BPA-17, at 22. BPA testified that excess factoring can be defined generically as that amount of factoring service (energy distributed among hours to match a load shape), measured in kWh, which is outside the factoring benchmarks. *Id*. at 20. Incurring excess factoring results from the lack of a corresponding change in the customer's resource amounts, not from load variation. "Only when customer resources have hour-to-hour variability is there a possibility of receiving factoring service amounts which are less or greater than the entitlement amount." *Id*. at 19-20. SUB's witness contends that situations outside the customer's control (such as retail outages or weather forecast error) could cause Excess Factoring Charges to occur. Nelson, WP-02-E-SP-01, at 11. BPA agrees. An error in forecasting that causes a customer to apply its resources in a shape that is outside the factoring benchmarks--anywhere between flat and following actual and complete load shape--could trigger excess factoring charges. *See* Keep *et al*., WP-02-E-BPA-17, at 20. Therefore, when the customer applies its resources counter to its load shape, BPA's factoring service could be forced outside of the benchmarks established in the basic product. *Id*. SUB errs in its analysis by attributing this variation in take from BPA, which is outside the benchmarks of the basic product, to load variation. In the circumstances described by SUB, the additional variation is caused by the customer's inability to forecast its loads accurately enough to stay within the bounds of the basic product.

BPA notes that it responded to the concern raised by SUB regarding forecast error and the Excess Factoring Charge. Because BPA will be unable to distinguish whether excess factoring was due to forecast error versus operational or commercial choices made by the utility, it is possible that forecast error could incur Excess Factoring Charges. Keep *et al*., WP-02-E-BPA-43, at 35. Since BPA will not be able to separate excess factoring that was due to circumstances outside the customer's control from those within the customer's control, all are treated as excess factoring in the basic product. *Id*. Different customer load resource situations could greatly influence the significance of load forecast error, but these cannot be addressed generically. *Id*. Case-specific FPS-priced resource variability products could be negotiated to replace Excess Factoring Charges for forecast error. *Id*. This is consistent with BPA's testimony that BPA is willing to "offer a limited amount of excess factoring service through a resource variability product priced under the FPS rate schedule to customers purchasing the complex partial product . . . However, this is a product and contract issue rather than a rate case issue." *Id*. at 34.

Decision

In the rate case BPA has not created an exemption from Excess Factoring Charges for excess factoring events related to customer forecast error. BPA will negotiate customer-specific flexibilities outside the scope of the rate case in Subscription contract negotiations.

Issue 5

Whether BPA should reduce within-day Excess Factoring Charges to correspond to reductions for within-month factoring when the customer experiences UAI Energy Charges.

Parties' Positions

PPC argues that BPA should make a reduction for within-day factoring to correspond with BPA's proposal to reduce within-month factoring quantities by any unauthorized increase energy amounts for the comparable diurnal period. PPC Brief, WP-02-B-PP-01, at 38.

BPA's Position

Because there is a possibility that some combination of factors on a customer's system could trigger UAI Charges and Excess Factoring Charges simultaneously, BPA will allow mitigation or avoidance of such charges. Keep *et al.*, WP-02-E-BPA-17, at 24. The amount of energy subject to the Within-Month Excess Factoring Charges will be reduced by the amount of energy which is levied the UAI Charge for energy in the same diurnal period. *Id*. at 25.

Evaluation of Positions

PPC noted that BPA proposes to reduce within-month factoring quantities by any UAI Energy amounts for the comparable diurnal period. PPC Brief, WP-02-B-PP-01, at 38. PPC contends that BPA should make a corresponding reduction for within-day factoring. *Id*. PPC presented no rationale for this offset, except to note that BPA did such an offset for within-month factoring.

BPA proposed a level of mitigation that it determined was reasonable, that being the reduction of Excess Within-Month Factoring by any UAI Charge for energy in the same diurnal period. Keep *et al*, WP-02-E-BPA-17, at 25. Within-month factoring deals with the quantity of energy delivered: "Those boundaries represent a take from BPA that falls between flat and meeting all of the customer's load variations for the period." Keep *et al.*, WP-02-E-BPA-17, at 21. The GRSPs provide that the within-month factoring test establishes an upper and lower boundary for each diurnal period of the day. Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 93. Since both unauthorized increase energy and excess within-month factoring deal with the quantity of energy delivered, there is a clear correlation between the two penalties. That, coupled with the likelihood (though not certainty) that an UAI Energy Charge event would result in an Excess Within-Month Factoring Charge, led BPA to mitigate the penalty charges. *Id*. at 24.

The GRSPs include an adjustment to the amount of energy subject to Excess Factoring Charges when a customer incurs both an UAI Charge for energy and a Within-Month Excess Factoring

Charge. Keep *et al.*, WP-02-E-BPA-17, at 25. Specifically, the amount of energy subject to the Within-Month Excess Factoring Charges will be reduced by the amount of energy which is levied the UAI Charge for energy in the same diurnal period. *Id*.

The intent of the penalty charges is to provide customers with a sufficient incentive to avoid placing unauthorized increases and excess factoring on BPA. *Id*. Without this mitigation to the Excess Factoring Charges, the collective penalty amounts would go beyond BPA's intent. *Id*.

Unlike within-month factoring, BPA's excess within-day factoring is not a quantity test. Nor is there a direct or constant correlation between unauthorized increase energy and excess within-day factoring. Within-day factoring places no boundaries on the amount of energy taken from BPA. *See* Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 92-93. When within-day factoring has occurred, BPA has in effect provided a shaping service associated with the customer's resources rather than its load. Keep *et al.*, WP-02-E-BPA-17, at 22. BPA has testified that the customer's hour-by-hour energy take from BPA is compared to the average energy take in the same period. *Id*. at 20. This average energy amount can be any amount from no energy to the customer's entire system load without triggering the Excess Within-Day Factoring Charge. Since the within-day factoring test is a test of shape rather than quantity, BPA does not agree that UAI Energy charges should offset Excess Within-Day Factoring Charges.

Because within-day factoring is not assessed based on the amount of energy taken in a day, there is no direct and constant correlation between unauthorized increase energy and excess within-day factoring. Therefore, UAI Energy Charges will not offset excess within-day factoring charges.

<u>Decision</u>

BPA will not reduce Within-Day Excess Factoring Charges to correspond to reductions for within-month factoring when the customer also experiences UAI Energy Charges.

<u>Issue 6</u>

Whether BPA's factoring charges expose customers to substantial retroactive penalty.

<u>Parties' Positions</u>

OURCA argues that the Excess Factoring Charge is unreasonable because it imposes a penalty that is retroactive. OURCA Brief, WP-02-B-OU-01, at 7. OURCA reiterates this argument in its brief on exceptions. OURCA Ex. Brief, WP-02-B-OU-01, at 6.

<u>BPA's Position</u>

The Excess Factoring Charges would apply only to products that customers may choose to subscribe to in the future under BPA's Subscription process. Burns *et al*., WP-02-E-BPA-08, at 8-9. Excess Factoring Charges will be applied in the BPA billing process. Keep *et al*., WP-02-E-BPA-17, at 19.

Evaluation of Positions

OURCA cites *Allegheny Power System*, 85 F.E.R.C. ¶ 61,370 (1998) to support the proposition that penalties are unreasonable if they are retroactive, because they serve no practical deterrent. OURCA Brief, WP-02-B-OU-01, at 7. OURCA argues that BPA admits that the Within-Day Charge may expose customers to a substantial retroactive penalty because of inadvertent load forecast. *Id*., citing Keep *et al*., WP-02-E-BPA-43, at 35. OURCA believes that these charges should be eliminated or revised. *Id*.

OURCA's reliance on the *Allegheny Power System* case is misplaced and fails to support OURCA's proposition. In that case, FERC found that, in filing revisions to its open access *pro forma* transmission tariff, Allegheny Power's proposed revisions might have allowed Allegheny Power to charge undefined and possibly retroactive penalties. 85 F.E.R.C. ¶ 61,370, 62,415. Although FERC ordered Allegheny Power to remove such provisions, FERC stated that Allegheny was free in a new proceeding to propose and support additional, specific penalties that Allegheny believes are necessary. *Id*. Similarly, BPA proposed on a prospective basis a charge that applies in the event customers exceed their contracted-for amounts of service. Keep *et al*., WP-02-E-BPA-43, at 34. In addition, because BPA recognizes there could be situations in which load forecast error occurs, BPA is offering additional products to replace excess factoring for forecast error. *Id*. at 35. OURCA claims that BPA admits that the Within-Day Factoring Charge may expose customers to a substantial retroactive penalty because of inadvertent load forecast error. OURCA Brief, WP-02-B-OU-01, at 7. Despite OURCA's claim, the record clearly shows that BPA testified that because BPA will be unable to distinguish whether excess factoring was due to forecast error versus operational or commercial choices made by the utility, it is possible that forecast error could incur Excess Factoring Charges. Keep *et al*., WP-02-E-BPA-43, at 35. Since BPA will not be able to separate excess factoring that was due to circumstances outside the customer's control from those within the customer's control, all are treated as excess factoring in the basic product. *Id*. Different customer load and resource situations could greatly influence the significance of load forecast error, but these cannot be addressed generically. *Id*. Case-specific FPS-priced resource variability products could be negotiated to replace excess factoring charges for forecast error. *Id*.

Decision

BPA's factoring charges do not expose customers to retroactive penalties. To account for load forecast error, BPA will offer case-specific FPS-priced resource variability products to replace Excess Factoring Charges for forecast error.

Issue 7

Whether the Excess Factoring Charge should exempt from its calculations load swings caused by cogeneration and renewable resources over which the utility customer does not exercise control, and which are not the result of power marketing activities.

Parties' Positions

WPAG argues that imposing the Excess Factoring Charge on cogeneration and renewable resources, without recognition of their unique operating characteristics, is bad public policy. WPAG Brief, WP-02-B-WA-01, at 22. WPAG contends that the Excess Factoring Charge as currently formulated will discourage the development of cogeneration and renewable resources by utility customers, and unfairly impose a penalty on those who have already developed such resources. *Id*. at 23.

BPA's Position

The Subscription Strategy is BPA's approach to marketing Federal power for the period FY 2002-2006. Burns *et al*., WP-02-E-BPA-08, at 6. The Strategy addresses the availability and marketing of power, describes power products, lays out strategies for pricing, including risk management, and discusses contract elements. *Id*. at 7. BPA's product designs for Subscription core products were adopted in the Subscription Strategy ROD, and the decisions contained in that document are not at issue in this rate case. *Id*. A goal of the Subscription Strategy is to provide market incentives for the development of conservation and renewables as part of a broader BPA leadership role in the regional effort to capture the value of these and other emerging technologies. *Id*. The Subscription product provisions for the Generation Management Services product recognize that some resources could qualify for treatment, referred to as measured amount netting, which is similar to that suggested by WPAG. *See* BPA Power Products Catalog, December 1999, at 56-58. Also, in the resource declaration parameters of the Actual Partial Service-Complex product, point 4 states "If the customer acquires new renewable resources *for which it wishes to declare a firm capability*," indicating that such resources will not be required by BPA to have declared firm capabilities. (Emphasis added.)

Evaluation of Positions

WPAG is concerned about application of the Excess Factoring Charge to renewable and cogeneration resources over which the customer has little or no control, and the output of which varies based on factors unrelated to market decisions. WPAG Brief, WP-02-B-WA-01, at 22. Although WPAG points out a potential problem with the application of the Excess Factoring Charge, WPAG does not indicate why a rate exemption would be necessary or more appropriate than the measures adopted under the Subscription Strategy and Power Products catalog. Those measures allow for resource-specific treatment that is consistent with BPA's policies. A blanket exemption for resources by generation type, *i.e*., cogeneration or renewable, might have effects beyond those intended under the policy objectives BPA adopted in the Subscription Strategy.

Decision

While BPA agrees with the premise, BPA will continue with its strategy to address the appropriate treatment of cogeneration and renewable resources outside the scope of the rate case within customer-specific Subscription contract negotiations.

10.8 Applicable Rate for Pre-Subscription Contracts that have Collared Price Provisions

Some Pre-Subscription contracts include price provisions that base the contract price on the lowest cost-based rate that goes into effect on October 1, or the successor of the PF-96 rate, as established in this current power rate proceeding. Keep *et al*., WP-02-E-BPA-17, at 26. These price provisions include collars, such that if the price for the contract or a specified test price, as based on the final PF-02 rate, exceeds the collar, the contract price is then equal to or based on the upper collar. *Id.* If that same calculation is below the lower collar, then the price for power sold under such contracts is equal to, or based on, the lower collar. *Id*. The prices in collared Pre-Subscription contracts are to be calculated based on the lowest cost-based rate that goes into effect on October 1, 2001, or the successor to the PF-96 rate. *Id.* For the purposes of determining the appropriate charge for the Pre-Subscription contracts, BPA will use the five-year average rate. *Id.* Pre-Subscription contracts provide that the contract price be established once and only once after the final PF-02 rates are published. *Id.* Establishment of the five-year average rate applicable to pre-Subscription contracts is consistent with BPA's Power Subscription Policy ROD at 120. *Id.* Because no party raised the issue of the applicable rate for pre-Subscription contracts that have collared price provisions, this issue is withdrawn in accordance with the *Procedures Governing Bonneville Power Administration Rate Hearings*, §1010.3, 51 Fed. Reg. 7611 (1986).

10.9 Stepped-Up Multiyear Block Charge (SUMY)

The SUMY Block Charge applies to Block purchases if annual amounts specified at the outset of contractual commitment increase (*i.e.* step-up) over multiple years of a purchase commitment term due to projected increases in customer net requirements which are not subject to a TAC. Keep *et al.*, WP-02-E-BPA-17, at 10. BPA's Subscription core 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. *Id*. The SUMY Block Charge provides BPA with cost coverage to meet these established changes in net requirements for subsequent purchase years. *Id*. The charge is associated with a Block purchase, which steps up over its multiyear term, and may be applicable to the basic Block purchase even if the purchaser also selects to purchase an add-on product such as Factoring or Shaping Capacity. *Id*. at 12. The charge is applied to the total multiyear Block energy purchase amount, including the stepped-up amounts. *Id*. at 11-12.

Block increase amounts will be determined during the Subscription window and fixed by BPA and the customer prior to the signing of the contract. *See* section 2.3.5.2, Wholesale Power Rate Development Study, WP-02-E-BPA-05. The SUMY Block Charge will be applied when amounts for any year, month, or monthly HLH and LLH periods of a multi-year declared Block purchase are greater than the first year's amount. *Id*. These additional purchase amounts will be assumed by BPA to be purchased at market prices. *Id*. The charge for these increased purchase amounts will be the difference between PF rates and the AURORA monthly on and offpeak market price forecast. *Id*. The pricing methodology approximates the incremental cost BPA must bear in providing the SUMY Block. *Id*. The charge will be computed for each customer based on its increasing Block profile. It will equal the total cost of the SUMY Block service divided by the total Block energy purchase including stepped-up amounts. The charge will be applied to the entire Block purchase and be in addition to the PF or NR energy and demand rates that the customer will pay for these power purchases. Keep *et al.*, WP-02-E-BPA-17, at 12-13. The formula for calculating the charge is described in the Wholesale Power Rate Schedules under the Adjustments, Charges, and Special Rate Provisions section. *See* Wholesale Power Rate Schedules, Appendix 1, WP-02-A-02, Section II.S.

<u>Issue 1</u>

Whether the proposed SUMY Charge should be eliminated.

<u>Parties' Positions</u>

PPC argues that the proposed SUMY Block Charge should be eliminated because it recovers market prices for services which should be cost-based pursuant to BPA's statutory ratemaking directives. PPC Brief, WP-02-B-PP-01, at 32-34; PPC Ex. Brief, WP-02-R-PP-01, at 7. Further, PPC claims, the SUMY is unnecessary due to BPA's advance knowledge of a customer's net requirements for the term of the contract. PPC Brief, WP-02-B-PP-01, at 34. OURCA adopts and joins the PPC's recommendation to eliminate the SUMY Block Charge. OURCA Brief, WP-02-B-OU-01, at 7-8; OURCA Ex. Brief, WP-02-R-OU-01, at 4. ICNU argues the SUMY charge creates an egregious form of discrimination and that BPA could plan to meet these loads now and meld the cost into the 7(b) rate. ICNU Brief, WP-02-B-IN-02, at 8; ICNU Ex. Brief, WP-02-R-IN-01, at 10-11.

<u>BPA's Position</u>

BPA has established that eliminating the SUMY Block Charge would lead to an underrecovery of BPA's costs associated with the cost of increasing the FBS to serve increasing load. Keep *et al*., WP-02-E-BPA-43, at 20. Under the SUMY Block Charge, BPA is estimating the cost of increasing the FBS to be the cost of purchasing power at the market prices forecast by AURORA. *Id*. Therefore, the SUMY Block Charge ensures BPA's ability to capture all costs associated with serving load placed on BPA by customers purchasing stepped-up blocks of power.

<u>Evaluation of Positions</u>

PPC argues that because of certain factors, the SUMY Block Charge should be eliminated. PPC Brief, WP-02-B-PP-01 at 32. PPC argues that loads will be known by September 30, 2000, the close of the Subscription window. *Id.* Such PF load is "expected" as that term has been used in the imposition of the TAC. *Id*. PPC incorporates the load/resource balance analysis it made with respect to BPA's load/resource balance analysis described in the TAC section. *Id*. PPC alleges that BPA's expectations of resource deficit are not on solid foundation, given deficiencies in BPA's load/resource balance analysis, its disinclination to recall surplus sales, and its policy decisions to serve non-preference customers. *Id*. ICNU suggests that BPA could plan to meet the load now and meld the cost into the 7(b) rate. ICNU Brief, WP-02-B-IN-02, at 8; ICNU Ex. Brief, WP-02-R-IN-01, at 10.

BPA agrees that the SUMY Block amounts will be known in advance. However, even with advance knowledge of customers' net requirements, BPA still incurs costs for serving this stepped-up load due to the costs that will be incurred to increase the FBS. Keep *et al.*, WP-02-E-BPA-43, at 22. The Load Variance Charge does not apply to sales of Block power. Keep *et al*., WP-02-E-BPA-17, at 8. The SUMY Block Charge, therefore, provides BPA with cost coverage to meet these established changes in net requirements for subsequent purchase years. *Id*. at 10. It provides BPA the same type of load growth coverage for the Block product, and thus recovery of costs, that the Load Variance Charge recovers from the Full and Partial Requirements products.

The Load Variance Charge covers the load growth costs associated with Full and Actual Partial Service. Keep *et al*., WP-02-E-BPA-43, at 22. Load growth for customers purchasing Full and Actual Partial Service is estimated, and costs to serve are unknown. *Id*. In comparison, the SUMY Block purchaser pays for its increase in net requirements through the SUMY Block Charge. *Id*. The increase in the stepped-up amount of the Block power may be due to any increase in net requirements. *Id*. Simply because the purchase of the amount of the Block is known in advance does not minimize or reduce BPA's need for the SUMY Block Charge. Without the SUMY Block Charge, BPA risks underrecovering its costs and revenues, because customers purchasing the stepped-up Block will not be paying the costs BPA will incur to serve the load growth component.

The load growth component of the Load Variance Charge is estimated based on forecast loads and is not take-or-pay on a predetermined amount, but instead on actual net requirements. Keep *et al*., WP-02-E-BPA-17, at 11. The load growth component of the SUMY Block Charge will not be known until time of contract signing. *Id.* ICNU suggests that BPA could plan to meet SUMY Block loads now and meld the cost into the 7(b) rate. ICNU Brief, WP-02-B-IN-01, at 8; ICNU Ex. Brief, WP-02-R-IN-01, at 10. ICNU argues that approach is consistent with BPA's statutory obligations to provide the firm net requirements of preference customers "whenever requested." ICNU Ex. Brief, WP-02-R-IN-01, at 10, citing 16 U.S.C. §839c(b)(1). It is important to recognize that BPA acknowledges it has an obligation to meet the net requirements of its preference customers with the FBS and replacements thereto. Keep *et al*., WP-02-E-BPA-43, at 22. The language "whenever requested" in section 5(b)(1) of the Northwest Power Act refers to BPA's offer of a power sales contract to its utility customers. Once a contract is executed under section 5(b)(1), BPA will serve load thereunder in accordance with the terms of the contract, at the applicable rates then in effect. The Load Variance Charge is based on forecast loads, but BPA is not forecasting any SUMY Block load. There are no SUMY Block loads for estimating a charge nor any purchase class in which to spread the charge; therefore, no revenue reductions to the revenue requirement are assumed from SUMY Block loads. The only reductions to the revenue requirement for energy are the capacity and load variance components of electric power. *See* section 3.2.3, Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 52. Revenues from all other components of sales are assumed to equal costs, and therefore they would not have any further impact on net revenue requirement. When the SUMY Block purchase becomes known, then "BPA can purchase SUMY Block amounts in advance any time before they are needed." Keep *et al*., WP-02-E-17, at 11. Without the imposition of the SUMY Block Charge, the costs associated with serving the load growth component of the increased Block would not be recovered. Under the SUMY Block Charge, BPA is estimating the cost of increasing the FBS to be the cost of purchasing power at the market prices forecast by AURORA. *Id*. at 20.

PPC argues that BPA's expectations of resource deficits are not on solid foundation. PPC Brief, WP-02-B-PP-01, at 33. To support its claim, PPC argues two points: first, there are deficiencies in BPA's load/resource balance analysis and second, BPA is disinclined to recall surplus sales and has made policy decisions to serve nonpreference customers. *Id*. These arguments are addressed by BPA in the TAC section of this ROD, section 10.15.

PPC's next example points to BPA's decision to serve nonpreference customers. PPC contends that BPA is disinclined to recall surplus sales and has made policy decisions to serve nonpreference customers. PPC Brief, WP-02-B-PP-01, at 33; PPC Ex. Brief, WP-02-R-PP-01, at 7. As shown by BPA in response to similar legal issues raised by PPC in section 10.15 on the TAC, BPA has clear legal authority to make sales to nonpreference customers. Such sales are not prohibited in order to reduce the cost of power to public agency customers. *See* Burns and Elizalde, WP-02-E-BPA-37, at 4.

Decision

BPA will not eliminate the SUMY Block Charge, because it is needed to recover costs associated with meeting load growth under the multiyear stepped-up Block purchase.

Issue 2

Whether the method for computing the SUMY Block Charge is cost-based and in accord with BPA's ratemaking directive to set cost-based rates.

Parties' Positions

PPC and OURCA argue that the SUMY Block Charge is not cost-based as it should be, pursuant to BPA's statutory ratemaking directives. PPC Brief, WP-02-B-PP-01, at 32-34; PPC Ex. Brief, WP-02-R-PP-01, at 7; OURCA Brief, WP-02-B-OU-01, at 7-8; OURCA Ex. Brief, WP-02-B-OU-01, at 7.

ICNU argues that the SUMY Block Charge is "an attempt to charge market-based rates for load growth which BPA should provide from Federal Base System resources . . ." ICNU Ex. Brief, WP-02-R-IN-01, at 11.

BPA's Position

The SUMY Block Charge is cost based, as BPA anticipates that it will be purchasing in the market to cover the cost of increasing the FBS for the stepped up Block amounts. Tr. 1189-1190. The estimated cost is the market prices forecast by AURORA. Keep *et al.*, WP-02-E-BPA-43, at 22.

Evaluation of Positions

PPC argues that the SUMY Block Charge should be cost-based and that the method proposed is not cost-based. PPC Brief, WP-02-B-PP-01, at 32. PPC claims that determining the proposed SUMY Block Charge using market-based prices violates BPA's statutory ratesetting directive for implementation of cost-based rates. *Id*.

BPA testified that the SUMY Block Charge is cost-based, as BPA's forecast of its loads and resources shows that it will be necessary for BPA to purchase in the market to serve such increases in Block loads. Keep *et al*., WP-02-E-BPA-17, at 12-13; Keep *et al*., WP-02-E-BPA-43, at 22; Tr. 1191-1192. BPA also acknowledges its obligation to meet the net requirements of its preference customers with FBS and replacements thereto, and when it does so, BPA must recover its costs. Keep *et al*., WP-02-E-BPA-43, at 20.

PPC's argument that the SUMY Block Charge is not cost-based appears to reflect the position that any power that BPA purchases from the market to serve preference agency customer load is not cost-based pursuant to section 7(b)(1) of the Northwest Power Act. 16 U.S.C. §839e(b)(1). ICNU shares a similar position and argues that if the FBS is not sufficient to meet these requirements, BPA should augment or supplement the FBS, or add replacement resources, and it should meld in those costs with other PF costs. ICNU Ex. Brief, WP-02-R-IN-01, at 11. Contrary to PPC's and ICNU's contention, however, the SUMY Block Charge is a cost-based charge. Tr. 1189, 1190. Power purchased to meet the stepped-up load that is subject to the SUMY Block Charge is FBS replacement power, Keep *et al*., WP-02-E-BPA-43, at 20; Tr. 1189, 1190; the cost of which must be recovered consistent with section 7 of the Northwest Power Act. Pursuant to section 3(10) of the Northwest Power Act, BPA may acquire resources to replace reductions in capability. Section 3(10) expressly provides that such replacement resources are FBS resources. For this reason, BPA's costs included in the SUMY Block Charge to replace reductions in the capability of the FBS resources constitute the costs of FBS resources. Under section 7(e), BPA has broad authority to design its rates to recover its total costs to meet its revenue requirement. To meet the cost of load growth under the stepped-up Block, an adjustment charge such as the SUMY Block Charge is appropriate. 16 U.S.C. §839e(e). "In short, the statute does not require BPA to impose any particular type of rate on its customers. Rather it restricts BPA only to 'sound business principles' in setting rates to meet its revenue requirements." *City of Seattle v. Johnson*, 813 F.2d 1364 (9th Cir. 1987).

Section 7(e) of the Northwest Power Act grants the Administrator considerable rate design discretion, including the ability to employ rate designs that use a value-of-service approach or market-based approach, or rate designs which recover BPA's costs through formula rates or pricing methodologies. Section 7(e) provides that:

> Nothing in this chapter prohibits the Administrator establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal, or other rate forms.

16 U.S.C. §839e(e).

BPA's rates are "cost-based" in the sense that BPA's rates "have regard to" cost recovery and, in the aggregate, do ultimately result in total cost recovery. Nevertheless, within the context of those directives, section 7(e) and its legislative history make clear that the cost allocation directives concern the amount of revenues to be recovered from customer classes, and not the design of the rates to recover those revenues. Congress did not direct BPA to use specific rate structures or billing practices to show the cost of new power supplies. As a result, it was recognized that many provisions could lead to rate reforms. *See, e.g., Comptroller General of the United States, Comments on Pacific Northwest Power Planning and Conservation Act* - H.R. 8157, reprinted in Cong. Rec. H 10687 (November 17, 1980).

Decision

The method for computing the SUMY Block Charge is cost-based and is in accord with BPA's statutory ratemaking directives

Issue 3

Whether the SUMY Block Charge is comparably priced for the equivalent service provided under the Load Variance Charge for meeting load growth.

Parties' Positions

PPC claims that the SUMY Block Charge is not comparably priced, as it provides an equivalent service to the service provided to purchasers of Full and Partial requirements service, but at a much higher price. PPC Brief, WP-02-B-PP-01, at 32-34.

BPA's Position

The two different methods for allocating load growth costs to the Load Variance Charge and SUMY Block Charge are appropriate. Keep *et al.*, WP-02-E-BPA-43, at 22. The Load Variance Charge covers for load growth costs associated with Full and Actual Partial Service using option pricing, which includes a risk premium because load growth is estimated and unknown. *Id*. The SUMY Block Charge covers for load growth costs using the AURORA market forecast, which does not include a risk premium because stepped-up amounts are known in advance. *Id*.

Evaluation of Positions

PPC argues that the SUMY as designed fails BPA's own rate objective to provide an equivalent service that is provided to purchasers of Full and Partial requirements service through the Load Variance Charge. PPC Brief, WP-02-B-PP-01, at 33. PPC concludes that the proposed pricing differential defies logic. *Id*. PPC claims that they are not remotely comparable because the SUMY Block Charge is approximately one mill greater than the 0.8 mill Load Variance Charge. *Id*.

PPC's conclusion that the SUMY Block Charge and Load Variance Charge are not comparable is based upon assumptions provided by PPC to BPA to calculate the pricing differential that resulted in the disparity. PPC references BPA rebuttal testimony, where a SUMY Block Charge is calculated at 2.23 mills/kWh, and compares this amount to the Load Variance Charge of 0.8 mills/kWh and concludes that the two charges are not comparable. PPC Brief, WP-02-B-PP-01. PPC's charge comparison fails to account for the different amounts of load growth assumed in building each charge. The SUMY Block Charge example referenced by the PPC (referencing BPA rebuttal, WP-02-E-BPA-43, at 21) is based upon assumptions the PPC submitted to BPA that defined the levels for which BPA made its comparison. PPC requested that BPA use a load growth increase amount of 10 percent. The Load Variance Charge used a load growth of approximately 1.2 percent. The 1.2 percent was never actually stated in testimony as a percent, but instead was referred to as being the load growth reflected in the NWPPC's forecast of public and Federal agencies' TRL. *See* Loads and Resources Study, WP-02-E-BPA-01, WP-02-E-BPA-01 and Loads and Resources Study Documentation, WP-02-E-BPA-01A. The calculation of the Load Variance Charge in Volume 2, section 4.1, Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05B, section 4.1, shows TRL both with and without load growth; the load growth of approximately 1.2 percent can be calculated from these amounts. The 2.23 mills/kWh charge was determined using the 10 percent stepped-up amount scenario as requested by the PPC. Had PPC requested the same 1.2 percent stepped-up amounts for its SUMY Block purchase scenario as was used for load growth in the Load Variance Charge, the SUMY Block Charge would have resulted in a charge of 0.31 mills/kWh. This lower charge for SUMY, given the same assumption for load growth, is appropriate, because the SUMY charge does not include a risk premium. Keep *et al*., WP-02-E-BPA-43, at 22. PPC has no reasonable evidence to support its claim that BPA's SUMY Block Charge pricing differential defies logic or that it results in noncomparable charges.

Decision

The SUMY Block Charge is comparably priced for the equivalent service provided under the Load Variance Charge for meeting load growth.

Issue 4

Whether applying the SUMY Block Charge to the entire PF Block purchase amount is appropriate.

Parties' Positions

PPC and OURCA argue that the SUMY Block Charge should be applied only to the stepped-up amounts and not to the entire Block purchase amount. PPC Brief, WP-02-B-PP-01, at 32; OURCA Brief, WP-02-B-OU-01, at 8; OURCA Ex. Brief, WP-02-R-OU-01, at 7.

BPA's Position

Applying the SUMY Block Charge to the entire Block purchase amount is consistent with BPA's proposal to bill all load at a posted rate. Keep *et al.*, WP-02-E-BPA-17, at 11; Keep *et al*., WP-02-E-BPA-43, at 23.

Evaluation of Positions

PPC and OURCA argue that they do not understand why BPA applies the SUMY Block Charge to the entire Block purchase and not just the incremental purchase. PPC Brief, WP-02-B-PP-01, at 32; OURCA Brief, WP-02-B-OU-01, at 8; OURCA Ex. Brief, WP-02-R-OU-01, at 7; Opatrny *et al.*, WP-02-E-PP-02, at 18.

BPA proposed to apply the SUMY Block Charge to the entire Block purchase because it is an efficient and simple billing method, which results in a charge that allows BPA to bill on total kWh sold rather than bill on different kWh amounts in different years. Keep *et al.*, WP-02-E-BPA-17, at 11; Keep *et al*., WP-02-E-BPA-43, at 23; Tr. 1193. The charge is developed using only the stepped-up amounts. *Id.* It is then spread across and charged to all kWh, including the stepped-up amounts. *Id*. The charge for the stepped-up amounts could have been billed on only the stepped-up amounts in a number of different ways; *e.g*., charged separately for each monthly diurnal period, for each separate month, for each yearly diurnal period, or for each separate year. Regardless of the billing method chosen, the resulting customer bill would be no different under any one of the scenarios than it would be by spreading the total cost of the stepped-up amounts over all Block amounts. Parties have not provided argument for why charging the cost to only the stepped up amounts is a superior method.

Decision

It is appropriate to apply the SUMY Block Charge to the entire PF Block purchase amount.

10.10 Flexible Rate Options

10.10.1 Flexible Priority Firm Power (PF) and New Resource Firm Power (NR) Rate Options

Issue

Whether BPA should continue to offer optional flexible demand and energy charges within the PF and NR rate schedules.

Parties' Positions

Parties did not address this issue in their initial briefs.

BPA's Position

BPA proposed to continue the Flexible PF and NR rates in order to provide BPA a flexible marketing tool. Gustafson and Thompson, WP-02-E-BPA-23, at 7-9.

Evaluation of Positions

The Flexible PF and NR rates provide BPA a useful marketing tool. Gustafson and Thompson, WP-02-E-BPA-23, at 7. While these rates ensure that BPA receives the same revenues on a net present value (NPV) basis that BPA would have received under the posted rates, the flexible rates allow BPA to structure payments to better meet customers' needs. *Id.* For example, BPA's ability to compete will be improved if it can offer a five-year Block sale of power, at 100 percent load factor, take-or-pay, at a single rate expressed in mills/kWh. BPA might otherwise be placed at a competitive disadvantage with some customers if it could offer only the more complex pricing embodied in the PF and NR rate schedules with their different seasonal and diurnal energy charges and a separate demand charge. *Id.* The Flexible PF and NR rates will be offered at BPA's discretion to PF Preference and NR purchasers. *Id.* BPA intends to offer these rates only to customers that make a purchase commitment to BPA. *Id.*

BPA proposed wide discretion in the structure of the Flexible PF and NR rates. *Id.* Before offering the rates to a customer, however, BPA will ensure that a revenue test has been satisfied. *Id.* at 7-8. The revenue test requires that the revenues for each specific agreement must be the same on a NPV basis that BPA would have received under a strict application of the PF or NR rate schedule. *Id.* at 8. This continues a fundamental principle of the revenue test contained in BPA's current Flexible PF and NR rates. *Id.*

BPA proposed three changes to the Flexible PF and NR rates: (1) eliminating the cash-flow test from the revenue test; (2) prohibiting the use of the Flexible PF and NR rates to flatten out the PF-02 and NR-02 stepped rates; and (3) prohibiting use of the Flexible PF and NR rates for indexed sales. *Id.* The cash-flow test was a requirement that forecasted revenues from all purchasers under the Flexible PF and NR rates would not create an annual cash-flow problem for BPA when compared to forecasted revenues at the charges specified in the PF-96 and NR-96 rate schedules. *Id.* The cash-flow test has been eliminated from the revenue test for a number of reasons. *Id.* First, BPA received very few requests from customers to have lower rates in the beginning of the rate period with higher rates in the later years. *Id.* These are the types of requests that would have affected cash flow in the early years. *Id.* Furthermore, with proposed three- and two-year stepped rates, BPA does not expect to receive many of these requests in the FY 2002-2006 rate period. *Id.* Second, the cash-flow test would create an additional workload for BPA staff. *Id.* If BPA retained the cash-flow test, BPA would have to establish new tracking tools. *Id.* Since BPA expects that it would receive very few of these requests, BPA can reduce workload by not having to create a tracking system. *Id.* Finally, BPA proposed that higher risk sales such as cost-based indexed deals no longer be allowed under this rate. *Id.* at 8-9. For these reasons, the cash-flow test was deemed unnecessary. *Id.* at 9.

Customers cannot use the Flexible PF and NR rates for cost-based indexed purchases. *Id.* Customers can still receive a cost-based index rate, but not through the Flexible PF and NR rates. *Id.* Specific parameters have been established elsewhere for cost-based indexed PF and NR sales. *Id.*; *see* Buskuhl *et al.,* WP-02-E-BPA-21, and ROD section 10.16.1.

The Flexible PF and NR rates cannot be used to change the PF-02 and NR-02 stepped rates to set a rate that is the same for each year of the five-year rate period. Gustafson and Thompson, WP-02-E-BPA-23, at 9. The Flexible PF and NR rates cannot be used to flatten out the stepped rates, because customers can use the five-year posted rate for PF and NR purchases to establish a flat rate for the FY 2002-2006 rate period. *Id.* Customers can, however, use the Flexible PF and NR rates to change the within-year design to obtain a flat rate within the year, or to obtain some other design that better matches their cash-flow needs. *Id.*

Decision

BPA will continue to offer optional flexible demand and energy charges within the PF and NR rate schedules.

10.10.2 Flexible Industrial Firm Power (IP) Rate Option

Issue

Whether BPA should offer optional flexible demand and energy charges within the IP rate schedule.

Parties' Positions

Parties did not address this issue in their initial briefs.

BPA's Position

BPA proposed to make the Flexible IP rate option available to its DSI customers to better meet customers' needs. Ebberts, WP-02-E-BPA-22, at 11-12.

Evaluation of Positions

BPA proposed to continue the Flexible rate option to its PF and New Resource rate customers, and the same option would also be made available to DSI customers. Ebberts, WP-02-E-BPA-22, at 11-12. While the Flexible rate option ensures that BPA receives the same revenues on a NPV basis that BPA would have received under the posted rates, the Flexible rates allow BPA to structure payments to better meet customers' needs. *Id.* BPA intends to offer this rate option only to DSI customers that make a purchase commitment to BPA under one of the IPTAC rates. *Id.* The Flexible rate option will allow a DSI customer to structure its seasonal and diurnal rates differently than allowed under the posted IPTAC rate schedules. *Id.* Before offering the rates to a customer, however, BPA will ensure that a revenue test has been satisfied. *Id.* The revenue test requires that the revenues for each specific agreement must be the same, on a NPV basis, that BPA would have received under a straight application of the IPTAC rate schedule. *Id.* This continues a fundamental principle of the revenue test contained in previous BPA Flexible rate offers. *Id.* Customers can receive a cost-based indexed rate with the IPTAC, but not through the Flexible rate option. *Id.* Specific parameters have been established elsewhere for the cost-based indexed IP rate. *See* Buskuhl *et al.*, WP-02-E-BPA-21, and ROD section 10.16.2.

Decision

BPA will offer optional flexible demand and energy charges within the IP rate schedule.

10.11 Five-Year Flat-Block Price Forecast

Issue

Whether BPA has properly developed the Five-Year Flat-Block Price Forecast.

Parties' Positions

The DSIs argue that additional resources will be brought online in the western United States over the next three years. DSI Brief, WP-02-B-DS-01, at 32-40. These resource additions will reduce the upward pressure on energy prices, and the escalation in energy prices should begin to revert to the historical negative trend. *Id.* BPA should revise its estimated price for five-year flat-block power to $25.36/MWh. *Id.* The DSIs raised identical arguments in their brief on exceptions. *See* DSI Ex. Brief, WP-02-R-DS-01, at 5. BPA will retain citations to the DSIs' initial brief in the discussion below, but will not add additional citations to their brief on exceptions.

BPA's Position

BPA developed a five-year flat-block price forecast for two purposes. Oliver *et al.*, WP-02-E-BPA-20, at 2. The first purpose is for use in calculating the cash component of the proposed settlement of the REP with regional IOUs as described in BPA's Power Subscription Strategy. *Id.* The second purpose for this forecast is to estimate the purchase price for power for five-year flat blocks of energy to meet BPA's firm obligations. *Id.* at 3. BPA used a combination of qualitative and quantitative assessments as well as professional judgment to arrive at a price estimate of five-year block purchases. *Id*. BPA used actual market experience to derive a price estimate of five-year block purchases and confirmed this estimate by using a derivation of BPA's Marginal Cost Analysis Study, WP-02-E-BPA-04, market quotes for forward transactions in the five-year period, and a reasonable extrapolation of current market prices. *Id.*

Evaluation of Positions

For the purposes of this rate case, BPA has developed price forecasts to be used in: (1) designing rates; (2) determining surplus revenue; (3) calculating the cash component of the proposed settlement of the REP with regional IOUs; and (4) estimating the cost of augmenting the FBS with five-year flat-block purchases. Oliver *et al.*, WP-02-E-BPA-20, at 2.

For designing rates, BPA relies on the MCA, which uses the AURORA model. *Id.;* Conger *et al.,* WP-02-E-BPA-15. The MCA is described in detail in the testimony of Anderson *et al.,* WP-02-E-BPA-16. The testimony of Keep *et al.,* WP-02-E-BPA-17, describes how the MCA is used in rate design. For determining surplus revenue, BPA uses a forecast of prices based on the MCA but with adjustments. Oliver *et al.,* WP-02-E-BPA-20, at 2. This forecast is described in greater detail in the testimony of Conger *et al.*, WP-02-E-BPA-15. The five-year flat-block price forecast that BPA has developed for calculating the cash component of the proposed settlement of the REP and for estimating the cost of augmenting the FBS with five-year flat-block purchases is discussed below. Oliver *et al.*, WP-02-E-BPA-20, at 2.

BPA has developed a five-year flat-block price forecast for two purposes. *Id.* The first purpose is for use in calculating the cash component of the proposed settlement of the REP with regional IOUs as described in BPA's Power Subscription Strategy. *Id.* The Power Subscription Strategy, at 8-9, states:

> BPA's strategy is that IOUs may agree to a settlement of the Residential Exchange Program in which they would be able to purchase a specified amount of power under subscription for their residential and small farm consumers at a rate approximately equivalent to the PF Preference rate . . .
>
> In subscription, BPA proposes a settlement in which residential and small farm loads of the IOUs will be assured access to the equivalent of 1,800 aMW of Federal power for the 2002–2006 period. Of this amount, at least 1,000 aMW will be met with actual BPA 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.
>
> . . . Any cash payment will reflect the difference between the market price of power forecast in the rate case and the rate used to make such Subscription sales. The actual power deliveries for these loads will be in equal hourly amounts over the period . . .

Id. at 2-3. The other forecasts developed for this rate case, as discussed below, are not appropriate for estimating advance purchases of five-year flat-block energy. *Id*. at 3. Therefore, a separate forecast was developed for this purpose. *Id.*

The second purpose for this forecast is to estimate the purchase price for power for five-year flat blocks of energy to meet BPA's firm obligations. *Id.* BPA's firm obligations and firm resources are described in the Loads and Resources Study, WP-02-E-BPA-01. Some of BPA's firm obligations are met by making purchases during the rate period on an as-needed basis, depending on generation levels, hydro conditions, and weather conditions. Oliver *et al.*, WP-02-E-BPA-20, at 3. In addition, BPA anticipates making substantial purchases prior to the rate period for terms longer than one year to augment the FBS. *Id.* A forecast of the five-year price of the flat-block power acquired in the 1999-2000 market timeframe is a more accurate reflection of the costs and structure of these augmentation purchases than the other price estimates (*e.g.*, AURORA price forecast). *Id.*

BPA used a combination of qualitative and quantitative assessments as well as professional judgment to arrive at a price estimate of five-year block purchases. *Id.* BPA used actual market experience to derive a price estimate of five-year block purchases and confirmed this estimate by using a derivation of BPA's MCA, market quotes for forward transactions in the five-year period, and a reasonable extrapolation of current market prices. *Id.*

BPA used real market examples of flat-block forward purchases in its analysis. *Id.* at 4. Prior to the initial proposal, BPA made 250 aMW of block (flat energy) purchases in amounts greater than 25 aMW. *Id.* At the time these purchases were made, 12-month 5-year blocks of energy averaged approximately $26/MWh. *Id.* However, due to the normally expected large surplus from the FCRPS during the spring, BPA chose not to purchase for the months of April, May, and June. *Id.* These purchases were for the nine months (July through March) of each of the five years in the rate period. *Id.* The average price for these purchases was $29.70/MWh. *Id.* BPA expects to supply spring months with BPA's share of secondary energy if it purchases 9-month blocks, or it will purchase the full 12-month block. *Id.* It is BPA's expectation that the purchase of additional forward blocks will place upward pressure on the price of this power. *Id.* BPA expects the price will approach, but not reach, the $32.24/MWh MCA marginal cost. *Id.* Therefore, BPA assumes that as 250 MW increments are purchased, the price will rise from approximately $26/MWh (recent experience) to just over $30/MWh. *Id.* The average price is approximately $28.10/MWh. *Id.* The average price of this range reflects the average purchase price for all purchases. *Id.* At any given time, the prices will be above or below this average, but the average itself stands as a good proxy for the price of the total purchases. *Id.* The higher range of just over $30/MWh represents a high-side estimate for specific new generation based on a compilation of verbal and proprietary commercial information BPA has received on its trading floor from independent power producers, marketers, and other generation developers. *Id.*

BPA used the MCA as a starting point to derive a range of possible five-year flat-block prices. *Id.* The MCA estimates are described in detail in the Marginal Cost Analysis Study, WP-02-E-BPA-04, and the testimony of Anderson *et al.,* WP-02-E-BPA-16. The MCA marginal costs are equal to the hourly variable cost of the marginal resource (the cost associated with the last unit dispatched in least-cost order to meet the next hourly energy demand) for energy available at the Mid-C trading hub. Oliver *et al.*, WP-02-E-BPA-20, at 5. The flat-block price forecast estimated five-year purchases of 2,362 aMW (1,562 aMW of BPA purchases and 800 aMW of IOU purchases). *Id.* Rather than estimating the marginal cost of the last 1 kW, BPA assessed the average price of the last 4,724 aMW of the load associated with the resources on the margin in the WSCC using the AURORA model in the MCA. *Id.* BPA used the MCA price of the last 4,724 aMW because it was twice the level of load BPA is attempting to price. *Id.* Pricing this breadth of marginal resources, rather than the last 1 kW in AURORA, captures a more realistic representation of the prices BPA is likely to encounter when purchasing firm blocks of power for this period. Such a price estimate is more reasonable, because the wholesale market cannot precisely predict a marginal 1 kW price, particularly two years in advance of the sales period. *Id.* The 4,724 aMW of load in the Northwest represents a small fraction of the total energy available, approximately 108,000 aMW from the supply capability in the WSCC, even with the method previously described in this paragraph. BPA acknowledges that sellers of surplus power will attempt to approximate marginal value in the five-year period and sell their highest-cost resources first. *Id.* The conclusion drawn from this analysis is that the prices at which sellers will offer energy supply for five-year flat-block forward purchases will be between the marginal cost price resulting from the decremented load and the marginal cost price that represents the last 1 kW of load. *Id.*

In order to evaluate this broader band marginal analysis, BPA reduced the total load in the Northwest in the MCA by 4,724 aMW, which represents BPA making purchases for load that is being served by new and existing resources. *Id.* The resulting marginal cost price of a 4,724 aMW decrement to load is $23.81/MWh. *Id.* The marginal cost price from the MCA is estimated to be $32.24/MWh for the last kW. *Id.* The average price in this range is $28.03/MWh. *Id.* at 5-6. In summary, using this analytical approach, BPA concluded that parties conducting bilateral negotiations for the FY 2002-2006 period, for quantities of about 2,362 aMW, should expect prices to be between $23.81/MWh and $32.24/MWh with an average of $28.03/MWh. *Id.* at 6.

BPA assessed the future price of power by receiving market quotes from financial institutions for forward transactions in the five-year rate period. *Id.* At the time of the initial proposal, BPA discussed financial swap options with major financial institutions. *Id.* Quotes BPA received were for $28.00/MWh for 250 aMW of flat-block firm energy for the October 1, 2001, through September 30, 2006, period. *Id.*

BPA assessed historical market price escalation and forecast price escalation embodied in the MCA, and then calculated a range of future prices when these escalations are applied to the current market price. *Id.* This technique captures a historical look at market cycles and fundamental market changes inherent in the electricity industry, and a future perspective using the escalation of marginal cost pricing. *Id.* BPA used historical nominal prices for the most likely alternative generation additions from 1980 through 1997. *Id.* The annual escalation of energy prices from these generation sources during this period was minus 2.7 percent, as the marginal resource transitioned from coal generation to natural gas resources. *Id.* In contrast, the more recent market price escalation is reflected in the nominal annual escalation from the MCA for the October 1, 1999, to September 30, 2006, period; that is, 6.2 percent per year. *Id.* Assuming that it is possible for either the historical trend of the 17 years prior to 1997 to occur, or for recent escalation trends to continue over the long run, BPA applied each of these average annual escalation rates to the market price of flat forward blocks sold from October 1999 to September 2000. *Id.* at 6-7. The market price from BPA's trading floor during the initial proposal was approximately $25.50/MWh; applying these growth rates yields an average price range of $22.90/MWh to $32.58/MWh over the October 1, 2001, to September 30, 2006, period. *Id.* at 7. The current market price for the next fiscal year (October 2000 to September 2001) is several dollars higher than the previous year, which illustrates the volatility and upward pressure on the market. Given the wide range of prices possible using historical escalation and forecasted marginal cost escalation, it is reasonable to assert that the price of energy purchases in five-year forward blocks will fall within that range. *Id.*

In summary, based on recent market experience and confirmed by a variety of information using a derivation of the MCA, financial swap quotes, and a reasonable extrapolation of current prices using historical and forecasted assessments of price escalation, BPA has determined that a price of $28.10/MWh reasonably reflects the average long-term purchase price for five-year flat-block energy. *Id.*

The DSIs argue that while BPA staff does not believe that the AURORA marginal cost data is an appropriate direct measure of five-year flat block purchases, BPA staff uses AURORA for its

MCA and to inform the price level at which BPA buys and sells power. DSI Brief, WP-02-B-DS-01, at 33. BPA relies on the MCA, which uses the AURORA model for designing rates. The MCA is described in detail in the testimony of Anderson *et al.*, WP-02-E-BPA-16. The testimony of Keep *et al.*, WP-02-E-BPA-17, describes how the MCA is used in rate design. For determining surplus revenue, BPA uses a forecast of prices based on the MCA but with adjustments. Oliver *et al.*, WP-02-E-BPA-20, at 2. This forecast is described in greater detail in the testimony of Conger *et al.*, WP-02-E-BPA-15. The five-year flat-block price forecast that BPA has developed for calculating the cash component of the proposed settlement of the REP and for estimating the cost of augmenting the FBS with five-year flat-block purchases is discussed below. Oliver *et al.*, WP-02-E-BPA-20, at 2.

BPA relies on the MCA for designing rates, and BPA uses an adjusted price forecast based on the MCA for determining surplus revenues. Oliver *et al.*, WP-02-E-BPA-20, at 2. However, these forecasts are not appropriate for determining the price of five-year block purchases. *Id.* The MCA estimates are described in detail in the Marginal Cost Analysis Study, WP-02-E-BPA-04, and Anderson *et al.*, WP-02-E-BPA-16. *Id.* The MCA marginal costs are equal to the hourly variable cost of the marginal resource (the cost associated with the last unit dispatched in least-cost order to meet the next hourly energy demand) for energy available at the Mid-C trading hub. *Id.* There are several reasons why a forecast of the hourly marginal cost and a forecast of prices from a combination of daily, within-month, monthly, and annual products are not appropriate measures of five-year flat-block purchases. *Id.*

The structure of a five-year forward block purchase is not similar to an hourly product that is subject to real-time pricing based on the last 1 kW of demand. *Id.* at 8. As previously described, the MCA marginal costs are equal to the hourly variable cost of the marginal resource for energy available at the Mid-C trading hub, essentially the variable cost of the last 1 kW generated. *Id.* Five-year forward block purchases do not reflect the last 1 kW generated. *Id.* Rather, they reflect market participants' willingness to sell generation above their variable cost. *Id.* The MCA marginal cost estimates are used as an indication of what BPA expects to actually experience in the real-time market-clearing price for hourly bulk energy transactions during the rate period. *Id.* In contrast, these five-year blocks will be acquired in advance of the five-year period through bilateral agreements. *Id.* Further, the product that BPA is expecting to acquire is five-year, flat annual energy blocks over all hours of the year irrespective of overall demand levels and in amounts greater than one kW. *Id.* Therefore, using the MCA marginal cost estimates as a forecast for five-year block purchases is not appropriate. *Id.*

In addition, market participants do not have uniform or perfect information with respect to future supply and demand levels or market and economic conditions, particularly for periods starting 24 to 60 months in the future. *Id.* AURORA models the functioning of a competitive economic market system that has a theoretical solution of information and timing. *Id.* The market can generate solutions different from a theoretical model, because market participants are individually making decisions to build generating resources in the Northwest to meet perceived demand. *Id.* Market participants may be willing to sell below the expected marginal cost and above their variable cost for many reasons, including: to ensure cost recovery of a capital investment, to hedge against a high future risk exposure, and simply because they have a different view of the future market. *Id.* at 8-9. Market participants use bilateral transactions to diversify their portfolio of sales and cover purchases made to lock in an acceptable margin. *Id.* at 9.

Another reason why these forecasts are not appropriate measures of five-year flat-block purchases is that the risk profiles of buyers and sellers fundamentally diverge. *Id.* Sellers of assets are more likely to lock in prices above their variable costs to protect from the risk of a low market than to wait for potential high markets. *Id.* On the other hand, because buyers generally have a higher risk profile, they can either purchase when prices are perceived to be "reasonable" or wait to buy. Potential high markets for buyers pose less risk, because buyers have more substitution options than sellers. *Id.* Buyers can substitute electricity with gas and, of course, buyers can readily go out of business. *Id.* The result of the divergence of risk profiles enables transactions to occur at less than the expected hourly market clearing price. *Id.* Some market participants are likely to sell forward to hedge the risk of a lower market. *Id.* This market speculation contributes to energy available at a range of prices. *Id.*

BPA used AURORA and the resulting MCA price estimates to derive *a* range of possible five-year flat-block prices. Oliver *et al.*, WP-02-E-BPA-20, at 4. BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. *Id.* BPA used a combination of qualitative and quantitative assessments as well as professional judgment to arrive at a price estimate of five-year flat-block purchases. *Id.* BPA used actual market experience to derive a price estimate of five-year flat-block purchases and confirmed this estimate by using a derivation of BPA's MCA, market quotes for forward transactions in the five-year period, and a reasonable extrapolation of current market prices. *Id.* at 3-7. The combination of the four methods accounts for pricing cycles and potential new generation, which provides strong support for the price forecast of $28.10. Oliver *et al.*, WP-02-E-BPA-45, at 2.

The DSIs note that they reviewed and proposed changes to the inputs to the AURORA model. DSI Brief, WP-02-B-DS-01, at 33. The DSIs concluded that AURORA results were fairly sensitive to the absolute amount and type of generation specified in the inputs. *Id.* The AURORA model has iterative logic that assumes new generation will be built exactly when market prices will pay for the generation. *Id.* The DSIs argue that while they agree with the theoretical soundness of AURORA logic, the actual markets can be volatile and do not respond exactly according to theory. *Id.* The DSIs argue that the supply/demand balance is a significant factor for price, and that if demand approaches the limits of physical supply, generation with higher variable costs is brought into operation, and the higher prices encourage developers to install new generation with prices eventually moderating to the full cost of new resources. *Id.* at 34. The DSIs argue that the opposite is also true, as demonstrated by BPA's AURORA test to confirm its estimate of the cost of five-year flat-block power. *Id.* When BPA reduced total load in the Northwest by 4,724 aMW, the resulting marginal cost of the decremented load was $23.81/MWh, significantly lower than BPA's $32.24/MWh average annual marginal cost of undecremented load. *Id.* First, it should be noted that issues regarding the AURORA model are addressed in detail in ROD chapter 4, Marginal Cost Analysis. However, in response to the DSIs' arguments on the five-year flat-block forecast, as previously noted, BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. Abundance of supply and constraints on supply are addressed in the combination of the four methods, which accounts for pricing cycles and potential new generation. Oliver *et al.*, WP-02-E-BPA-45, at 2.

First, using actual market experience contemplates pricing cycles and uncertainty, in that sellers today will sell based on their evaluation of generating resources coming online and the possible resulting decline in market prices. *Id.* Otherwise, all sellers would simply hold their supply until a future date to sell at a higher price. *Id.*; Oliver *et al.*, WP-02-E-BPA-20, at 8.

Second, by using a derivation of the MCA and the AURORA model, BPA has implicitly evaluated the five-year flat-block price forecast in the context of market cycles. Oliver *et al.*, WP-02-E-BPA-45, at 2. The MCA assumes generation coming online and being retired, which could contribute to a pricing cycle(s). *Id.* BPA has acknowledged that sellers today will price blocks of power for less than the last 1 kW of load, or the marginal cost of new generation. *Id.* at 2-3; Oliver *et al.*, WP-02-E-BPA-20, at 5, 8-9. BPA analyzed this situation by decrementing the load forecast in the MCA with twice the level of BPA's expected purchases. Oliver *et al.*, WP-02-E-BPA-45, at 3. This analysis results in a price of $23.81/MWh compared to a price of $32.24/MWh in the MCA. *Id.* Comparing this with BPA's estimated price of $28.10/MWh, BPA concludes that it is reasonable that the average price of BPA's potential purchases will be between the price resulting from decrementing load in the WSCC and the last 1 kW. *Id.*

Third, the very pricing mechanism used by financial institutions to develop market quotes hinges on market volatility, which contemplates market cycles. *Id.*

Fourth, BPA directly acknowledges market cycles by extrapolating market prices (current during the initial proposal) using the historical market price escalation and the forecast price escalation in the MCA. *Id.* This technique captures a historical look at market cycles and fundamental market changes inherent in the electricity industry, and a future perspective using the escalation of marginal cost pricing. *Id.*; Oliver *et al.*, WP-02-E-BPA-20, at 6. The result of this analytical technique is a range of prices from $22.90/MWh to $32.58/MWh. *Id.* BPA's estimated price of $28.10/MWh falls well within this range, the range within which market cycles are likely to occur. Oliver *et al.*, WP-02-E-BPA-45, at 3.

In summary, by using four approaches to derive and confirm BPA's five-year flat-block market price forecast, BPA demonstrated that it not only contemplated market cycles and variations resulting from changes in generation but also factored them into BPA's evaluation. *Id.* Nonetheless, it is BPA's experience that market price changes occur due to a variety of factors besides generation plant additions, such as economic conditions, hydrologic conditions, fuel prices, regulatory/legislative decisions, and generation plant retirements. Oliver *et al.*, WP-02-E-BPA-45, at 5.

The DSIs argue that decrementing load will tend to affect marginal costs in a manner similar to adding an equivalent amount of new generating capability. DSI Brief, WP-02-B-DS-01, at 34. For valid AURORA results, the DSIs claim it is therefore necessary to take into account any generation not included in the initial AURORA inputs but that could conservatively be expected to be online during the 2002-2006 rate period. *Id.* The DSIs argue that almost 17,000 MW of new generation has been proposed for construction in California, over 5,000 MW in the PNW, almost 2,000 MW in Canada, and almost 1,000 MW in the remainder of the WSCC region. *Id.* at 34-35. The DSIs argue that the level of proposed generation suggests that an increase in the price of power over the last three years is leading to an increase in planned generation. Thus, it was necessary to include in AURORA inputs for that portion of the proposed generation that had a high likelihood of actually being constructed before or during the rate period. *Id.* at 35. As noted previously, issues regarding the AURORA model are addressed in detail in ROD chapter 4, Marginal Cost Analysis. In response to these arguments, however, as previously noted, BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. The combination of the four methods accounts for pricing cycles and potential new generation. Oliver *et al.*, WP-02-E-BPA-45, at 2, 5.

Both BPA's initial proposal and the DSIs' proposal consider adding new generation. The Joint DSIs' approach directly inputs (hardwires) an exogenous forecast of new generation. Bliven *et al.*, WP-02-E-DS/AL/VN-02, at 46-47. The BPA approach adds new resources based on standard economic logic. Anderson *et al.*, WP-02-E-BPA-42, at 7. The BPA approach will add new generation when a resource's revenues exceed its costs. *Id.*

The new generation forecast proposed by the DSIs lacked background substantiation. *Id.* at 8. This approach did not address the detailed specifics of forecasting cyclical prices. *Id*. at 7-8. The DSIs also did not describe how historical cycles are appropriate, or may adapt, to a changed electric market-driven by independent power producers and smaller scale generation. *Id.* at 8. The data provided by the DSIs produced results in conflict with the DSIs' testimony. *Id.* at 3. BPA could not adopt data that was inconsistent with the supporting testimony. BPA added new generation based on the economic logic in AURORA. *Id.* at 7. This method is based on economic logic rather that an exogenous forecast prepared by the DSIs. *Id.* at 7. The method used by BPA to forecast new generation is reasonable.

The DSIs argue that the AURORA logic adds generic resources at generic costs when economical and that AURORA is, in effect, a combined forecast. DSI Brief, WP-02-B-DS-01, at 35. While the DSIs do not take issue with the appropriateness of such a forecast, they argue that AURORA must be supplied accurate inputs, including generation sufficiently along in the planning and construction process to make it likely to be brought online. *Id.* The DSIs argue that the amount of generation in question is not a forced overbuild scenario, but simply moderates the rise in prices that would otherwise occur as the AURORA results converge toward the long-term incremental cost of generation. *Id.* As previously noted, however, BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. The combination of the four methods accounts for pricing cycles and potential new generation. Oliver *et al.*, WP-02-E-BPA-45, at 2, 5.

BPA agrees that reasonable data should be supplied to derive a reasonable forecast. The basic inputs driving BPA's forecast of new generation are the annual load forecast and the cost of new resources. *See* ROD chapter 4. No party raised any issue with respect to these variables. The methodology which uses these data to derive a new generation forecast is based on standard economic logic and was supported by WPAG. Cross *et al.*, WP-02-E-WA-02, at 35-37.

The new generation forecast proposed by the DSIs lacked background substantiation. Anderson *et al.*, WP-02-E-BPA-42, at 7-8. This approach did not address the detailed specifics of forecasting cyclical prices. *Id.* at 7-8. The DSIs also did not describe how historical cycles are appropriate, or may adapt, to a changed electric market-driven by independent power producers and smaller scale generation. *See* ROD chapter 4. The data provided by the DSIs produced results in conflict with the DSIs' testimony. *Id*. at 3. BPA could not adopt data that were inconsistent with the supporting testimony.

The DSIs argue that in addition to the existing resources available to AURORA, the DSIs included 4,823 MW of planned new generation with completion dates through 2002. DSI Brief, WP-02-B-DS-01, at 36. The DSIs included about 147 MW of renewable generation funded from California public purpose fees and about 3,000 MW of new merchant generation as a conservative estimate of new generation that would come online in California in the near term. *Id.* The DSIs argue that the generation they have noted is expected to come online earlier than the generic generation that AURORA would construct, but the total amount (4,823 MW) is less than AURORA would build (8,000 MW). *Id.* As noted previously, BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. The combination of the four methods accounts for pricing cycles and potential new generation. Oliver *et al.*, WP-02-E-BPA-45, at 2. Further, it is BPA's experience that market price changes occur due to a variety of factors besides generation plant additions, such as economic conditions, hydrologic conditions, fuel prices, regulatory/legislative decisions, and generation plant retirements. *Id*. at 5. BPA acknowledges that the DSIs have a different forecast of new generation than BPA. BPA's forecast of new generation is reasonable. *See* ROD chapter 4, which fully describes BPA's criteria for its decision on the DSIs' proposal for their exogenous forecast of new generation.

The DSIs argue that as the new generation completed before the end of 2002 comes online: (1) the hourly marginal costs generated by AURORA will be lower by roughly the same amount as the hourly marginal costs decreased when BPA removed 4,724 aMW of load from the AURORA inputs; and (2) the cost of augmenting BPA's system with flat-block power will be less. DSI Brief, WP-02-B-DS-01, at 36. It is important for BPA to evaluate the amount of generation likely to come online over the next three years and to take into account the effect of this generation on the cost of augmentation. *Id.* Further, the DSIs argue that the resources they forecast will be installed in the WSCC are based on the DSIs' detailed analysis of real world construction plans described in their testimony. DSI Brief, WP-02-B-DS-01, at 37. The DSIs argue that BPA should take account of these real world plans in its own forecast of the market price of block purchases. *Id.* at 37-38. Again, BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. The combination of the four methods accounts for pricing cycles and potential new generation. Oliver *et al.*, WP-02-E-BPA-45, at 2. *See also* *Id*. at 5. BPA has reviewed and commented on the data proposed by the DSIs for new construction. This analysis is included in ROD chapter 4. BPA's data and method for forecasting new generation are reasonable. This analysis is also included in Chapter 4.

The Joint DSIs' forecast of new generation is based, in part, on an analysis of historical cyclical factors. Bliven *et al.*, WP-02-E-DS/AL/VN-02, at 46-47. The DSIs have not provided a complete analysis of this cyclical pattern. Anderson *et al.*, WP-02-E-BPA-42, at 7-8. The DSIs have not noted how a historical cyclical pattern may change in an evolving electric power market. *Id.* at 7-8. The DSIs' data produce results that are inconsistent with the results of their testimony. *Id.* at 3. BPA could not use DSI data that BPA could verify was inconsistent with the DSIs' testimony.

The DSIs argue that BPA's marginal cost panel acknowledged that there are resources under construction in the geographic area modeled by AURORA. DSI Brief, WP-02-B-DS-01, at 36-37. The panel also acknowledged that the inputs it used in AURORA to develop market prices did not reflect any such resources. *Id.* at 37. The panel agreed that the costs of completing and then operating a previously partially complete resource were less than building and operating a resource from scratch. *Id.* The BPA panel also acknowledged that if one were to include partially completed resources, then such resources would be selected by AURORA prior to generic greenfield resources and may be placed in operation at an earlier time than a greenfield resource. *Id.* BPA did not make any independent judgment of whether the new resources that the DSIs believed were sufficiently far along in the planning and construction process to be reasonably certain of being completed and brought online would in fact be constructed. *Id.* In response to these arguments, as noted above, BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. The combination of the four methods accounts for pricing cycles and potential new generation. Oliver *et al.*, WP-02-E-BPA-45, at 2, 5.

The effects of new generation on marginal costs are fully accounted for in BPA's MCA. Anderson *et al.*, WP-02-E-BPA-42, at 7. BPA reviewed and commented on the approach and data proposed by the DSIs for forecasting new generation. *Id.* at 6-8. BPA's approach relies on standard economic logic to forecast new generation. Anderson *et al.*, WP-02-E-BPA-16, at 3-4. The Joint DSIs' approach relies on an exogenous forecast. Bliven *et al.*, WP-02-E-DS/AL/VN-02, at 46-47. BPA's input data to the forecast of new generation were fully documented. Marginal Cost Analysis Study Documentation, WP-02-E-BPA-04A, at 3-10. No party critiqued the basic input data driving BPA's forecast of new generation. BPA commented on the applicability of the DSIs' data to forecasting new generation. Anderson *et al.*, WP-02-E-BPA-42, at 6-8. The DSIs' data were not consistent with the results of the DSIs' testimony. *Id.* at 3.

The DSIs argue that five-year flat blocks of power for the rate period will cost about $25/MWh. DSI Brief, WP-02-B-DS-01, at 38. The DSIs recommend that BPA use a price of $25.36/MWh in its rate case calculations, which is the average of two marginal costs developed by AURORA with the changes proposed by the DSIs. *Id.* The DSIs ignore that BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. The combination of the four methods accounts for pricing cycles and potential new generation. Oliver *et al.*, WP-02-E-BPA-45, at 2, 5.

BPA could not verify the DSIs' MCA forecast and thus the $25.36/MWh price. Anderson *et al.*, WP-02-E-BPA-42, at 3. BPA requested the DSIs' MCA AURORA output data base by means of a data request, but the DSIs did not supply BPA the results. *Id.* at Attachment 4. In data response BPA-DS/AL/VN:039, the Joint DSIs state "The requested output file is not available …. If we are able to reconstruct an output file that reflects our AURORA results, it will be provided to you." *Id.* at Attachment 4. BPA did not receive the output file. *Id.* at 4. BPA continues to rely on the four methods used to derive the $28.10/MWh, and BPA's reliable and verifiable results from AURORA.

The DSIs argue that BPA claimed that the added generation is not enough to significantly affect the AURORA price forecast, in that the resource addition changes the marginal cost from 32 mills/kWh to 29.6 mills/kWh. DSI Brief, WP-02-B-DS-01, at 38, citing Oliver *et al.*, WP-02-E-BPA-45, at 4. The DSIs argue that the marginal cost from BPA's MCA run is $32.24/MWh. *Id.*, citing Oliver *et al*., WP-02-E-BPA-20, at 5. The DSIs argue that the difference between the MCA results with and without the resource addition is $2.64/MWh, almost identical to the difference between BPA's estimated flat-block price of $28.10/MWh and the $25.36/MWh the DSIs developed recognizing that some resource additions in the western United States are almost certain to be online before 2002. *Id.* The DSIs fail to note that BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using AURORA was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. Using the four approaches to derive and confirm its five-year block price forecast, BPA has captured the range around price uncertainty due to possible market variations (price and market cycles) and, therefore, $28.10 is a reasonable estimate. Oliver *et al.*, WP-02-E-BPA-45, at 8. Furthermore, BPA's five-year flat-block price forecast for a block purchase reflects a mid-range price between historical and forecast escalation rates, which accounts for the possibility of price volatility due to new generation development. *Id*. at 5.

The DSIs argue that the $25.36/MWh estimate is consistent with the data BPA staff reviewed. DSI Brief, WP-02-B-DS-01, at 38. The current market price (at the time of the initial proposal) from BPA's trading floor is approximately $25.50/MWh, citing WP-02-E-BPA-20, at 7. The historical price escalation for energy from generation sources from 1980 through 1997 is minus 2.7 percent per year, although recent escalation has been 6.2 percent per year. *Id.* at 38-39. The DSIs claim that the long-term price trend for energy is downward, and the increasingly competitive market for electricity makes it likely that the trend will continue for the time being. *Id.* They further argue that giving equal weight to the long-term trend in escalation and the very recent energy price runups produces an average market cost of $27.74/MWh. *Id.* at 39. The DSIs assert that if energy prices revert to the long-term trend, as they say is typical following a runup in prices, the expected value in the 2002-2006 period is much more likely to be in the range of $25/MWh or less. *Id.* It is important to note that BPA used four methods to derive and confirm the five-year flat-block price forecast of $28.10, of which the analysis using the historical and estimated future escalation was only one. Oliver *et al.*, WP-02-E-BPA-20, at 3-7. Using the four approaches to derive and confirm its five-year block price forecast, BPA has captured the range around price uncertainty due to possible market variations (price and market cycles) and, therefore, $28.10 is a reasonable estimate. *Id*. Furthermore, BPA's five-year flat-block price forecast for a block purchase reflects a mid-range price between historical and forecast escalation rates, which accounts for the possibility of price volatility due to new generation development. Oliver *et al.*, WP-02-E-BPA-45, at 5. Further, BPA believes that price escalation will likely be more toward the center of the range of the escalation in the MCA price forecast and escalation of historical prices. *Id*. at 7. BPA believes this based on the results of the three other techniques BPA used to examine its price estimate: actual market experience, a derivation of the MCA and the AURORA model, and market quotes for forward transactions. *Id.*

The DSIs argue that BPA has been making flat nine-month purchases for prices that average $29.70/MWh. DSI Brief, WP-02-B-DS-01, at 39. The DSIs state that BPA assumes it can purchase or sell flat spring energy for $16.12/MWh. *Id.* The annual average of these prices is $26.30/MWh. *Id.* BPA has assumed that as it purchases additional forward blocks, there will be upward pressure on the block price. *Id.* The DSIs argue that BPA's block purchases do not represent incremental load to the market. *Id.* The DSIs argue that to the extent BPA purchases power to serve new loads on BPA, represented by a return of public agency load diversified during 1996-2001 and 1,000 aMW of sales to the IOUs, the power currently serving these same loads will be released to the market. *Id.* Therefore, the DSIs assert that BPA's purchases do not represent an increase in demand and will not put pressure on the market price. *Id.* The DSIs claim that the downward price pressure created by planned new generation will result in reductions, not increases, in market prices. *Id.* BPA agrees with the concept that the augmentation load is not new load but returning load. These points are described in Oliver *et al.,* WP-02-E-BPA-20, at 5-6. However, BPA does not agree with the methodology of resource additions proposed by the DSIs. These points are addressed in ROD chapter 4. Furthermore, BPA does not agree that "planned generation" will result in downward pressure on prices. BPA recognizes that there is uncertainty in future market prices and that there will be a range of opinions as to whether the future price of power may be higher, lower, or relatively the same compared to current prices. Oliver *et al.*, WP-02-E-BPA-20, at 4. Applying the historical market price escalation rate and the marginal cost price forecast escalation rate in the MCA demonstrates this wide range of possibilities. *Id.;* Oliver *et al.,* WP-02-E-BPA-20, at 6-7. BPA believes that the market will likely assess the prices for five-year flat-block purchases within the aforementioned range, and that $28.10/MWh is a reasonable assessment of a price point. Oliver *et al.*, WP-02-E-BPA-45, at 4.

BPA has reviewed its testimony and has confirmed that by using four approaches to derive and confirm its five-year flat-block price forecast, BPA has captured the range around price uncertainty due to possible price and market cycles. Oliver *et al.*, WP-02-E-BPA-45, at 8.

Decision

BPA has properly established the Five-Year Flat-Block Market Forecast.

10.12 Low Density Discount (LDD)

In order to avoid adverse impacts on retail rates of BPA's purchasers with low system densities, BPA applies a discount, to the extent appropriate, to BPA's rates for such purchasers. Gustafson and Thompson, WP-02-E-BPA-23, at 2. In BPA's initial proposal, these rates included the PF Preference rate, the PF Exchange Program rate, the PF Exchange Subscription rate, the Residential Load (RL-02) rate, and the New Resources (NR-02) rate. *Id.* In BPA's initial proposal, the LDD applied to the following components of the foregoing rate schedules: (1) Demand; (2) HLH energy purchases; (3) LLH energy purchases; and (4) Load Variance. *Id.*

The methodology for calculating the LDD is explained in detail in BPA's Wholesale Power Rate Schedules, WP-02-E-BPA-07. In summary, a purchaser must satisfy five eligibility criteria. *Id.* Two of these criteria regard having a K/I (sales to investment) ratio less than 100 and a C/M (consumers per mile) ratio less than 12. *Id.* If a purchaser does not meet the five eligibility requirements, its LDD is zero. *Id.* If the purchaser satisfies the five requirements, the purchaser is eligible for the LDD. *Id.* Under the proposed methodology, BPA established a list of discounts that apply to the numerical results of the calculation of the two respective ratios. *Id.* The purchaser will receive the sum of the two potential discounts, but not in excess of 7 percent. *Id.* If the purchaser's revised discount varies from its current discount by more than one-half of 1 percent, BPA would progressively phase in the revised discount in annual increments of one-half of 1 percent until the purchaser receives its then-final revised discount. *Id.* Once the percentage discount is determined, the discount would be applied each month to the charges (excluding UAI Charges, Excess Factoring Charges, and charges for transmission services) for all power purchased from BPA under the PF Preference rate, the PF Exchange Program rate, the PF Exchange Subscription rate, the RL-02 rate, and the NR-02 rate. *Id.* at 2-3. The LDD reduces the recipient's monthly power bill by the applicable discount. *Id.* at 3.

Issue 1

Whether BPA should eliminate the Additional Adjustment for Very Low Densities.

Parties' Positions

Numerous parties advocate the retention of the Additional Adjustment for Very Low Densities. NRU Brief, WP-02-B-NI-02, at 19-20; PNGC Brief, WP-02-B-PN-01, at 22; PPC Brief, WP-02-B-PP-01, at 43.

BPA's Position

In BPA's direct testimony, BPA proposed to eliminate the Additional Adjustment for Very Low Densities. Gustafson and Thompson, WP-02-E-BPA-23, at 3. In BPA's rebuttal testimony, BPA advocated continuing the adjustment. Gustafson *et al.*, WP-02-E-BPA-48, at 2.

Evaluation of Positions

The Additional Adjustment for Very Low Densities was a feature of BPA's 1996 LDD that provided an additional discount of one-half percent to purchasers with a C/M ratio of 3 or less and a K/I ratio of 26 or less. Gustafson and Thompson, WP-02-E-BPA-23, at 3. In its initial proposal, BPA proposed to eliminate this adjustment because, of over 55 purchasers that receive the LDD, only one purchaser currently qualifies for this provision. *Id.* In BPA's rebuttal testimony, BPA noted that a number of parties argued that BPA should retain the Additional Adjustment for Very Low Densities. Gustafson *et al.*, WP-02-E-BPA-48, at 2. *See* Saven *et al.*, WP-02-E-NI-02, at 3-6; Thayer *et al.*, WP-02-E-PN-03, at 2-5; Hansen and O'Meara, WP-02-E-PP-08, at 2-3. In support of this position, the parties argued that: (1) even if only one utility is currently receiving the Additional Adjustment for Very Low Densities, it is still a valid provision; (2) there may be more than one utility eligible for the Additional Adjustment for Very Low Densities during the rate period; and (3) the time and expense to implement the Additional Adjustment for Very Low Densities is greatly exceeded by the benefits provided to purchasers. Gustafson *et al.*, WP-02-E-BPA-48, at 2. BPA concluded that the parties' arguments were well reasoned. *Id.* Based on those arguments, BPA proposed to continue the Additional Adjustment for Very Low Densities for the next rate period. *Id.* BPA will continue to monitor the Additional Adjustment for Very Low Densities, however, to ensure that there are still utilities eligible to receive the Additional Adjustment for Very Low Densities and that it continues to serve a valuable purpose. *Id.*

Decision

BPA will continue the Additional Adjustment for Very Low Densities.

Issue 2

Whether BPA should use TRL to define the power sales used in calculating "K" in the K/I ratio.

Parties' Positions

The parties did not generally oppose BPA's proposed change in calculating K. PNGC requests that BPA make clear that load that is supplied by a utility to a retail customer that is not on the utility's distribution system does not count toward TRL. PNGC Brief, WP-02-B-PN-01, at 23-24.

BPA's Position

In a retail access situation, the purchaser receiving an LDD may not be providing all of the power, or kWh, to the end-use consumer. Gustafson and Thompson, WP-02-E-BPA-23, at 3-4. The definition of K therefore, must be changed to reflect the possible development of retail access. *Id.* The proposed definition identifies the purchaser's "TRL" as the proper basis to calculate K. *Id.*

Evaluation of Positions

BPA's 1996 Wholesale Power and Transmission Rate Schedules, in the section governing the calculation of K for the K/I ratio, state that "[t]he Purchaser's total electric energy requirements include firm sales, nonfirm sales to firm retail loads, sales for resale, and associated losses." Gustafson and Thompson, WP-02-E-BPA-23, at 3. In a retail access situation, however, the purchaser may not be providing all of the power, or kWh, to the end-use consumer. *Id.* The definition of K therefore, must be changed to reflect the possible development of retail access. *Id.* at 3-4. The new definition identifies the purchaser's "TRL" as the proper basis to calculate K. TRL is defined, in pertinent part, as ". . . all electric power consumption within a utility's distribution system as measured at metering points, adjusted for unmetered loads or generation. No distinction is made between load that is served with BPA power and load that is served with power from other sources." *Id.* at 4. This change is appropriate for two reasons. *Id.* First, this would avoid LDD costs increasing as a result of a purchaser losing load, or kWh, to another supplier and having the purchaser's K decrease. *Id.* The purchaser would still be able to recover investment in their system through a distribution charge that most likely would not be tied to kWh sales. *Id.* Second, TRL is defined and used for several purposes in BPA's rate schedules. Using the term in the LDD keeps consistency throughout the rate schedules. *Id.*

PNGC notes that BPA did not want "K" to decrease to reflect a loss of power sales due to load being served by another power supplier. PNGC Brief, WP-02-B-PN-01, at 23. PNGC argues that this addresses only half of the problem. *Id.* A similar but opposite issue exists when load is gained through retail access. *Id.* PNGC argues that it is important to ensure that the current definition of TRL holds the LDD constant for either loss or gain due to retail access. *Id.* at 23-24. Therefore, if an LDD utility became the supplier for load that was not on its distribution system under some sort of retail access scenario, that off-system load should not be counted in the utility's TRL. *Id.* at 24. This solution would prevent an unfair increase in the "K" value that would result in a lower LDD value. *Id.* PNGC requests that BPA make clear that load that is supplied by a utility to a retail customer that is not on the utility's distribution system does not count toward TRL. *Id.* BPA agrees with PNGC's position. If an LDD utility becomes the supplier for load that is not on its distribution system under some sort of retail access scenario, that off-system load will not be counted in the utility's TRL. This interpretation is consistent with the definition of TRL in BPA's initial proposal. *See* Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 125.

Decision

BPA will use the purchaser's TRL as the proper basis to calculate K. Under some sort of retail access scenario, if an LDD utility becomes the supplier for load that is not on its distribution system, that off-system load will not be counted in the utility's TRL.

Issue 3

Whether BPA should revise the definition of consumers for the C/M ratio.

Parties' Positions

Parties did not address this issue in their initial briefs.

BPA's Position

BPA proposed that "[t]he C/M is calculated by dividing the maximum number of consumers on the distribution system, in any one month during the Calendar Year (CY), by the end of CY number of pole miles of distribution." Gustafson and Thompson, WP-02-E-BPA-23, at 4. *See* Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 99.

Evaluation of Positions

BPA proposed that "[t]he C/M is calculated by dividing the maximum number of consumers on the distribution system, in any one month during the Calendar Year (CY), by the end of CY number of pole miles of distribution." Gustafson and Thompson, WP-02-E-BPA-23, at 4. *See* Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 99. This clarification of consumers is necessary for two reasons. Gustafson and Thompson, WP-02-E-BPA-23, at 4. The first reason is to eliminate confusion regarding service to irrigation and seasonal consumers. *Id.* Some purchasers have previously averaged the months of service to irrigation and seasonal accounts and not counted them as 12-month consumers. *Id.* This is incorrect and affords the purchaser a higher LDD than is intended. *Id.* The second reason for this revision is to define which consumers to count in a retail access environment; that is, whether one counts the consumers to whom the purchaser sells power, or the consumers on the purchaser's distribution system. *Id.* BPA proposed that purchasers use the number of consumers on their distribution system. *Id.* The LDD was developed to offer benefits for purchasers with low-density systems to help offset the higher than usual distribution costs. *Id.* at 4-5. By counting the consumers on the distribution system, and not all consumers purchasing power from the purchaser, the LDD benefits stay with the distribution consumers. *Id.* at 5.

Decision

BPA will calculate the C/M ratio by dividing the maximum number of consumers on the distribution system, in any one month during the CY, by the end of CY number of pole miles of distribution.

Issue 4

Whether BPA should base the calculation of pole miles on the end of CY number of pole miles of distribution.

Parties' Positions

NRU argued that BPA should clarify the collection of data concerning the number of miles of distribution line for purposes of calculating the C/M ratio to provide that it does not exclude underground distribution lines from the calculation. Saven *et al.*, WP-02-E-NI-02, at 10.

BPA's Position

BPA proposed that the determination of pole miles should be based on the end of CY number of pole miles of distribution. Gustafson and Thompson, WP-02-E-BPA-23, at 5.

Evaluation of Positions

BPA's 1996 LDD requires purchasers to submit an average of two years of data on pole miles. Gustafson and Thompson, WP-02-E-BPA-23, at 5. BPA proposed that the determination of pole miles should be based on the end of CY number of pole miles of distribution. *Id.* This would simplify reporting requirements, thereby reducing the time it takes for purchasers to report to BPA and for BPA to implement the LDD. *Id.*

NRU argued that BPA should clarify the collection of data concerning the number of miles of distribution line for purposes of calculating the C/M ratio to provide that it does not exclude underground distribution lines from the calculation. Saven *et al.*, WP-02-E-NI-02, at 10. In rebuttal testimony, BPA noted that the reference to pole miles and the definition of pole miles in the 2002 initial proposal Wholesale Power Rate Schedules, WP-02-E-BPA-07, includes underground distribution lines. Gustafson *et al.*, WP-02-E-BPA-48, at 3.

Decision

The determination of pole miles will be based on the end of CY number of pole miles of distribution. The reference to pole miles and the definition of pole miles in BPA's 2002 Wholesale Power Rate Schedules includes underground distribution lines.

Issue 5

Whether BPA has proposed an appropriate effective date for LDD changes.

Parties' Positions

Parties did not address this issue in their initial briefs.

BPA's Position

BPA proposed that any changes to a purchaser's LDD amount should start on October 1 of each year. Gustafson and Thompson, WP-02-E-BPA-23, at 5.

Evaluation of Positions

BPA proposed that any change in a purchaser's LDD will be determined by application of the criteria described above to the data submitted by a purchaser by June 30 of each year. Gustafson and Thompson, WP-02-E-BPA-23, at 5. This will eliminate confusion over when a change to a purchaser's LDD is to take place. *Id.* There will be no retroactive changes. *Id.* All changes that are determined by data submitted by June 30 will occur on the upcoming October 1. *Id.*

Decision

All LDD changes that are determined by data submitted by June 30 will occur on the upcoming October 1.

Issue 6

Whether BPA should adopt a Benefits Legislation Exclusion.

Parties' Positions

Numerous parties opposed the adoption of a Benefits Legislation Exclusion. PNGC Brief, WP-02-B-PN-01, at 22; NRU Brief, WP-02-B-NI-02, at 19-20; PPC Brief, WP-02-B-PP-01, at 43-44.

BPA's Position

In BPA's initial proposal, BPA advocated a Benefits Legislation Exclusion and included it as part of the definition of the LDD in the GRSPs. Gustafson and Thompson, WP-02-E-BPA-23, at 5; Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 101-02. In its rebuttal testimony, BPA proposed that it is unnecessary at this time to include a Benefits Legislation Exclusion in the definition of the LDD. Gustafson *et al.*, WP-02-E-BPA-48, at 2-3.

Evaluation of Positions

The initially proposed Benefits Legislation Exclusion provided that if the Federal government or a state or local government adopted a law, regulation, or other provision that provides benefits similar to the LDD, then the purchaser's service territory within the jurisdiction of that provision would no longer be eligible to receive the LDD. Gustafson and Thompson, WP-02-E-BPA-23, at 6. The exclusion was intended to preclude the possibility of a utility benefiting from the LDD when the utility is able to benefit from a separate program for a similar purpose. *Id.* A number of parties opposed the Benefits Legislation Exclusion, citing numerous concerns. *See* Saven *et al.*, WP-02-E-NI-02, at 6-8; Thayer *et al.*, WP-02-E-PN-03, at 6-8; and Hansen and O'Meara, WP-02-E-PP-08, at 3-4. While BPA disagreed with virtually every argument raised by the parties in opposition to the Benefits Legislation Exclusion, BPA reconsidered its proposal to adopt the exclusion. Gustafson *et al.*, WP-02-E-BPA-48, at 2-3. BPA believes that the policy underlying the Benefits Legislation Exclusion is sound. *Id.* The Benefits Legislation Exclusion was created by BPA in response to legislative efforts to establish benefit programs similar to the LDD. *Id.* It is reasonable to consider whether BPA should offer an LDD when similar benefits are provided by other governmental entities. *Id.* Since the conception of the Benefits Legislation Exclusion, however, BPA has not witnessed the adoption of such provisions by state or local governments. *Id.* While BPA believes that it may be inappropriate for utilities to receive the LDD at the same time that such utilities benefit from similar programs provided elsewhere, BPA does not believe it is necessary to establish the Benefits Legislation Exclusion at this time. *Id.* BPA will continue to monitor retail access legislation on the Federal, state, and local government level to determine whether LDD benefits are being duplicated by another government's actions. *Id.* The provision of benefits similar to the LDD by other governmental entities during the rate period may require BPA to revisit this issue in its next rate proceeding. *Id.*

Decision

BPA does not include a Benefits Legislation Exclusion in the LDD.

Issue 7

Whether BPA should include a Retail Access Exclusion in the LDD.

Parties' Positions

NRU argues that BPA should clarify that the Retail Access Exclusion does not apply to new service resulting from bypass, utility mergers, the annexation of territory, or the acquisition of territory by voluntary purchase agreement. NRU Brief, WP-02-B-NI-02, at 20. PacifiCorp objects to BPA's proposal to extend eligibility to load gained through bypass or annexation of territory, so long as PacifiCorp's residential customers in southern Idaho are denied the benefits. PacifiCorp Ex. Brief, WP-02-R-PL-01, at 5.

BPA's Position

BPA proposed the adoption of a Retail Access Exclusion, which precludes LDD benefits for purchasers' new loads where the acquisition of the new load occurs as a result of retail access legislation by the Federal Government or a state or local government. Gustafson and Thompson, WP-02-E-BPA-23, at 6-7. BPA does not intend to have the Retail Access Exclusion prohibit the application of the LDD under circumstances that have been allowed prior to voluntary or mandatory retail access.

Evaluation of Positions

The Retail Access Exclusion precludes LDD benefits for purchasers' new loads where the acquisition of the new load occurs as a result of retail access legislation by the Federal Government or a state or local government. Gustafson and Thompson, WP-02-E-BPA-23, at 6-7. The gaining purchaser cannot provide the benefits of the LDD to the gained load. *Id.* If the acquisition would have been allowed prior to Retail Access Legislation, then the gained load is still eligible for LDD benefits. *Id.* The calculations for determining the LDD discount percentage are derived from consumers, costs, and sales associated with the purchaser's distribution system. *Id.* Therefore, the benefits of the LDD should stay with the consumers on the purchaser's distribution system. *Id.* This exclusion was proposed because some of BPA's customers that are not eligible to receive the LDD were concerned that, with the advent of retail access, customers receiving the discount would use LDD benefits as a means of acquiring the loads of customers that do not receive the LDD. *Id.* BPA agrees that LDD benefits should not be used as a means to acquire new load and should benefit only those consumers on a purchaser's distribution system. *Id.*

BPA agrees with NRU's clarification that the Retail Access Exclusion will not apply to new service resulting from bypass, utility mergers, the annexation of territory, or the acquisition of territory by voluntary purchase agreement. NRU Brief, WP-02-B-NI-02, at 20. If the acquisition would have been allowed prior to Retail Access Legislation, then the gained load is still eligible for LDD benefits. Under the circumstances noted above, a utility would be allowed to receive the LDD as long as these actions were allowed prior to any Federal, state, or local retail access legislation.

PacifiCorp argues that BPA denied PacifiCorp's request to extend the LDD to its southern Idaho customers, while approving several proposals to extend or maintain benefits of the LDD that were proposed by BPA's preference customers. PacifiCorp Ex. Brief, WP-02-R-PL-01, at 5. First, BPA makes its decisions on each issue based on the merits of each issue, not on the party that raises an issue. BPA's reasons for the decisions noted by PacifiCorp are explained in detail elsewhere in this section. In addition, a number of these changes are available to benefit both IOUs and preference customers that are eligible for the LDD, *e.g.*, the retention of the Additional Adjustment for Very Low Densities and the withdrawal of the Benefits Legislation Exclusion.

PacifiCorp objects to BPA's proposal to extend eligibility to load gained through bypass or annexation of territory, so long as PacifiCorp's residential customers in southern Idaho are denied the benefits. PacifiCorp Ex. Brief, WP-02-R-PL-01, at 5. PacifiCorp notes that by allowing load gained through bypass or annexation to be eligible for the LDD, and by expanding LDD benefits to preference customers but not to the IOUs, the Administrator's decision may add an additional incentive to public power takeovers of IOUs' facilities. *Id.* BPA disagrees with PacifiCorp, in that the LDD benefits are not being expanded as PacifiCorp suggests. As noted above, NRU requested a clarification and cited examples of service territory expansions that are presently allowed and eligible to receive LDD benefits. NRU was concerned that BPA would apply the Retail Access Exclusion section to actions that are presently allowed. In agreeing with NRU's clarification, BPA will still enforce the Retail Access Exclusion section if the load gained would not otherwise have been gained absent legislation. BPA is not expanding the benefits beyond what is presently allowed.

Decision

BPA includes a Retail Access Exclusion in the LDD.

Issue 8

Whether and how BPA should apply the LDD to the Slice product.

Parties' Positions

Parties advocate the application of the LDD to the Slice product. PNGC raises an implementation issue. PNGC Brief, WP-02-B-PN-01, at 22-23. PNGC notes that, when there are few or no non-Slice LDD recipients in a given discount bracket, instead of using a $/MWh value for each discount bracket, a linear relationship among the discount brackets should be established based on data available from non-Slice LDD customers; PNGC proposes a refinement. *Id.*

BPA's Position

BPA proposed that the LDD be applied to the Slice product. Wholesale Power Rate Schedules, WP-02-E-BPA-07(E5). BPA would determine a dollars/MWh rate that can then be used as the yearly/monthly discount for a Slice customer that is eligible to receive the discount. *Id.* BPA would use billing data from the previous CY when calculating the dollars/MWh discount rate for Slice customers. *Id.* The rate would be applied to only that portion of Slice power being purchased that is requirements power. *Id.* In its rebuttal testimony, BPA proposed a number of refinements to this approach. The $/MWh value would be adjusted by percentage increases or decreases in the PF Preference rate. Gustafson *et al.*, WP-02-E-BPA-48, at 4. Also, when there are no non-Slice LDD recipients available in a given discount bracket to calculate the $/MWh value, it is appropriate to determine a linear relationship using a regression analysis rather than a constant term. *Id.* at 4-5.

Evaluation of Positions

In the Wholesale Power Rate Schedules, WP-02-E-BPA-07(E5), BPA proposed that to be eligible for the LDD, customers that purchase the Slice product must meet the eligibility criteria under Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 100. BPA proposed that the LDD benefit for Slice customers would be determined and applied as follows:

> By September of each year, BPA will establish a dollars/MWh discount rate for each one-half percent discount bracket, from 0.5 percent to 7 percent. The dollars/MWh discount rate for each bracket will be determined by using billing data of customers within the same LDD percentage bracket. Those customers' total dollars in LDD discounts received will be divided by eligible MWhs purchased. This will result in a dollars/MWh rate that can then be used as the yearly/monthly discount for a Slice customer that is eligible, under section 3, to receive the same discount. BPA will use billing data from the previous Calendar Year when calculating the dollars/MWh discount rate for Slice customers.
>
> The rate will only be applied to that portion of Slice power being purchased that is requirements power. This quantity is defined in the Slice Contract as Critical Slice Amount. The annual Slice true-up will include an LDD true-up if based on estimates. If it is based on after the fact monthly data, no true up is necessary.

See Wholesale Power Rate Schedules, WP-02-E-BPA-07(E5).

PNGC argues that the use of previous CY data may falsely value the $/MWh value in years when BPA experiences a rate change (*i.e.*, third year of stepped-up rate, CRAC, and so on). PNGC Brief, WP-02-B-PN-01, at 22-23. *See* Thayer *et al.*, WP-02-E-PN-03, at 9. PNGC proposes that BPA should use previous CY data to estimate the $/MWh values, and at the end of the year BPA should use actual data to produce a final set of $/MWh. *Id.* BPA would then refund or bill any differences just like any other estimated bill. *Id.* In rebuttal testimony, BPA acknowledged that PNGC identified a legitimate concern. Gustafson *et al.*, WP-02-E-BPA-48, at 3-4. PNGC's proposal to treat the $/MWh value as an estimated amount and conduct a true-up at the end of the year is one approach to addressing this problem. *Id.* This approach, however, would place a greater administrative burden on BPA. *Id.* While there are some instances where it may be necessary, BPA would like to minimize the use of estimates and true-up practices in the implementation of BPA's rates. *Id.* An approach that would not impose this burden would be to adjust the $/MWh value by percentage increases or decreases in the PF Preference rate. *Id.* These increases or decreases would include changes in rates from the first three years of the rate period to the last two years of the rate period and the establishment of a new PF Preference rate. *Id.* This approach would not apply to increases due to the TAC, CRAC, or the DDC. *Id.* The reason BPA would not make an adjustment to the $/MWh value for these changes is because the Slice product and subsequent Slice rate are not subject to TAC, CRAC, or DDC. *Id.* Therefore, a change to the $/MWh value for those rate adjustments is not applicable. *Id.* By adjusting the $/MWh value by the percentage of a PF Preference rate increase or decrease, PNGC's concern regarding a "false value" is addressed, and a true-up would not necessary. *Id.*

In response to BPA's proposal, PNGC argues that it would accept BPA's alternative solution with the caveat that the percentage change in BPA's overall rates would not translate into identical percentages for individual customers. PNGC Brief, WP-02-B-PN-01, at 22. The only way for the percentage method to work would be for BPA to use the specific percentage change for each individual LDD-receiving utility. *Id.* For example, PNGC member utilities are actually receiving a rate increase from PF-96 to PF-02 because of changes in BPA's rate design, while the overall PF-96 to PF-02 revenues to BPA are stable. *Id.* at 22-23. Because of that anomaly, certain BPA customers receive rate increases, while BPA's overall rates remain stable. *Id.* at 23. BPA agrees with PNGC's solution to calculate the specific percentage change for each non-Slice utility receiving the LDD. When there is a PF rate change to energy, demand or load variance charge(s), BPA will calculate a new $/MWh rate using the previous year's energy and load data and the new rate(s). This calculation will be done for each individual non-Slice utility receiving the LDD and then averaged for each bracket the individual utility is in (*i.e.*, 0.5 percent to 7.0 percent LDD). This will result in a new $/MWh rate that reflects any rate changes.

PNGC argues that BPA proposes to determine a $/MWh value for each discount bracket, which may pose a problem if there are few or no non-Slice LDD recipients in a given discount bracket. PNGC Brief, WP-02-B-PN-01, at 23. *See* Thayer *et al.*, WP-02-E-PN-03, at 10. PNGC proposes that BPA determine a linear relationship among the discount brackets based on data available from the non-Slice LDD customers, possibly using a regression analysis and not a constant term. *Id.* The linearized $/MWh value for each discount bracket would be what was applied to the Critical Slice Amount to determine a Slice participant's LDD. *Id.* BPA would use previous CY data for the estimate and actual data for the final values. *Id.* In its rebuttal testimony, BPA acknowledged that PNGC has identified a legitimate concern. Gustafson *et al.*, WP-02-E-BPA-48, at 4-5. BPA agreed that, when there are no non-Slice LDD recipients available in a given discount bracket to calculate the $/MWh value, it is appropriate to determine a linear relationship using a regression analysis and not a constant term. *Id.* Use of previous year data is adequate for determining the $/MWh value and, as stated in the previous issue, BPA would increase or decrease the $/MWh value if a rate increase or decrease occurs in the year the discount is applied. *Id.* This would eliminate the need for later true-up calculations. *Id.*

PNGC argues that it does not object to the use of percentage increases for the value inputs as long as the data are gleaned on an individual LDD-eligible customer basis. PNGC, WP-02-B-PN-01, at 23. BPA proposed a number of refinements to this approach, including that the $/MWh value would be adjusted by percentage increases or decreases in the PF Preference rate to deal with possible rate changes. Gustafson *et al.*, WP-02-E-BPA-48, at 4. This issue is dealt with in Issue 9 below.

Decision

BPA will apply the LDD to the requirements portion of the Slice product using a calculation and adjustment for increases or decreases in the PF rate.

Issue 9

Whether energy rates alone should be used in calculating changes in the LDD due to changes in the PF rate.

Parties' Positions

PNGC argues that BPA should use the demand, load variance and energy components of the LDD applied to a non-Slice requirements customer to determine the percent change in the PF rate which then applies to the $/MWh LDD proxy. PNGC Ex. Brief, WP-02-R-PN-01, at 8-9.

BPA's Position

In the Draft ROD, BPA proposed to change the LDD amount applied to Slice in the event of a PF rate change using only the energy rates to calculate the percentage change in the PF rate. *See* Draft ROD, WP-02-A-01, at 10-76 through 10-78.

Evaluation of Positions

BPA proposed that the calculation of an increase or decrease in the PF rate would be a straight line percentage of the increase or decrease for each diurnal period identified in the HLH and LLH rate tables. Draft ROD, WP-02-A-01, at 10-77. Demand and load variance are not components of the Slice Product and therefore are not included in the equation. *Id.* PNGC argues that in the case of the LDD, the Draft ROD contains what appears to be an error. PNGC Ex. Brief, WP-02-R-PN-01, at 8-9. BPA has stated that it will change the LDD amount applied to Slice in the event of a PF rate change using only the energy rates to calculate the percentage change in the PF rate. *Id*. PNGC argues that this presents a false picture of any rate change. *Id*. BPA applies the LDD to Slice on a $/MWh basis because of the nature of the Slice product. *Id*. However, PNGC argues, for other non-Slice requirements customers, the LDD is given on demand, load variance and energy. *Id*. PNGC claims that to calculate changes in the LDD due to changes in the PF rate, it is necessary to calculate the LDD using all three components it is based on to non-Slice requirements customers. *Id*. PNGC notes that the $/MWh is only a proxy for full application because of the nature of the Slice rate. *Id*. PNGC notes that the allocation of costs between demand, load variance, and energy is a topic of much debate in any BPA rate case. *Id*. PNGC argues that using only energy may under- or over-state any PF rate change depending on the shift in allocation between the three components of the PF rate. *Id*. In this situation, PNGC claims, it will definitely understate any PF rate change for PNGC's members. *Id*. In summary, PNGC argues that BPA should use the demand, load variance, and energy components of the LDD applied to a non-Slice requirements customer to determine the percent change in the PF rate which then applies to the $/MWh LDD proxy. *Id*. BPA concludes that PNGC's arguments are well-reasoned. Changes in the PF rate will be calculated using all three PF rate components.

<u>Decision</u>

Changes in the LDD due to changes in the PF rate will be calculated using energy, demand, and load variance charges.

<u>Issue 10</u>

Whether BPA should allow qualification for the LDD to be calculated on a state-by-state basis when a multistate utility's retail rates within a state are based on a revenue requirement that contains only the costs of the utility's distribution facilities within that state.

<u>Parties' Positions</u>

PacifiCorp argues that its residential consumers in southern Idaho should be eligible for the LDD, because such customers are subject to higher rates due to low system densities and are presently ineligible for the LDD due to the higher system densities in Washington and Oregon. PacifiCorp Brief, WP-02-B-PL-01, at 3-9; PacifiCorp Ex. Brief, WP-02-R-PL-01, at 1-2. PacifiCorp also argues that BPA should apply the LDD to both the RL rate and the PF Exchange Subscription rate. *Id.* at 7-9; PacifiCorp Ex. Brief, WP-02-R-PL-01, at 3-4.

NRU argues that PacifiCorp's consumers should not be eligible for the LDD because existing LDD benefits have been limited, the Subscription ROD precludes increases in LDD costs, and PacifiCorp's proposal would violate the Northwest Power Act. NRU Brief, WP-02-B-NI-02, at 20-23.

<u>BPA's Position</u>

BPA did not take a position, for purposes of the PF Exchange Program rate or the NR-02 rate, on whether the LDD should be calculated on a state-by-state basis based on a multistate utility's retail rates within a state. Gustafson *et al*., WP-02-E-BPA-48, at 7-8. BPA wanted to review the parties' briefs on this issue. *Id.* BPA proposed that the LDD should not apply to the RL-02 and PF Exchange Subscription rates. Gustafson *et al.,* WP-02-E-BPA-48, at 9-10. In the Draft ROD, BPA proposed that the LDD should not be calculated on a state-by-state basis based on a multistate utility's retail rates within a state. Draft ROD, WP-02-A-01, at 10-78 through 10-84.

Evaluation of Positions

PacifiCorp argues that its customers in southern Idaho currently pay retail rates that are adversely affected by high distribution costs resulting from low system density in its sparsely populated Idaho service territory. PacifiCorp Brief, WP-02-B-PL-01, at 3. PacifiCorp notes that its customers are ineligible for the LDD because BPA calculates the LDD by taking the average system density of all of a utility's service territories, which in some cases can be extensive and may include other states. *Id.* PacifiCorp argues that current application of the LDD criteria unfairly penalizes PacifiCorp's southern Idaho customers. *Id.* PacifiCorp's retail customers in southern Idaho bear the full cost of the low-density distribution system, because PacifiCorp has higher density and less expensive distribution systems in other Northwest states. *Id.* Yet under the principles of state utility regulation, distribution costs are location-based, and therefore retail customers in southern Idaho obtain no benefits from the utility's higher-density distribution systems in other states. *Id.*

PacifiCorp argues that there is a disconnect between how IOU retail rates are set and how BPA determines eligibility for the LDD. PacifiCorp Brief, WP-02-B-PL-01, at 4. PacifiCorp argues that the lower-cost, higher-density distribution systems in PacifiCorp's other jurisdictions are not available to offset the adverse impacts of the higher-cost, lower-density distribution system in Idaho. *Id.* Therefore, PacifiCorp's residential and rural consumers in Idaho lose a discount given to other retail consumers in low-density service territories. *Id.* PacifiCorp argues that BPA should revise the LDD to provide that "for multistate utilities that include in rate base only electric distribution costs related to distribution facilities situated in a particular state, BPA shall compile the data submitted by the Purchaser on a state-by-state basis and calculate the ratios on a state-by-state basis, for the Purchaser's entire electric utility system in the PNW . . ." PacifiCorp Brief, WP-02-B-PL-01, at 5.

In its rebuttal testimony, BPA recognized that PacifiCorp's lower-cost, higher-density distribution systems in PacifiCorp's other jurisdictions are not available to offset the adverse impacts of its higher-cost, lower-density distribution system in Idaho. Gustafson *et al.*, WP-02-E-BPA-48, at 7-8. BPA expressed concern, however, with two issues. *Id.* First, under the Northwest Power Act, the LDD is applied "in order to avoid adverse impacts on retail rates of the Administrator's customers with low system densities." *Id.* Because the Act refers to "customers," BPA must determine the proper customer for application of the LDD. *Id.* On one hand, PacifiCorp is BPA's customer, even though it has jurisdictions in numerous states. *Id.* On the other hand, as PacifiCorp points out, the REP is implemented on a state jurisdictional basis, with PacifiCorp's Idaho service territory served by its Utah Division. *Id.*

Second, while the LDD is intended to avoid adverse impacts on retail rates of low-density customers, distribution costs are not the only costs that affect retail rates. *Id.* While lower-cost, higher-density distribution systems may not be available to offset the impacts of higher-density distribution systems, a large multistate utility might have economies of size or efficiencies in administration, resource planning, or other areas that might help to offset some of its higher distribution costs in its state jurisdictions. *Id.* A utility might have low retail rates despite higher than normal distribution costs. *Id.* BPA noted that it would like to review the parties' testimony and briefs on these issues to make an informed decision. *Id.*

PacifiCorp notes that BPA raised an issue regarding whether the Northwest Power Act's reference to customers meant PacifiCorp or PacifiCorp's customers, the residential and rural ratepayers of southern Idaho. PacifiCorp Brief, WP-02-B-PL-01, at 6. PacifiCorp acknowledges that the literal language of the statute may well refer to BPA's utility customers, but argues that retail ratemaking for IOUs is done on a state jurisdictional basis. *Id.* PacifiCorp argues that BPA should conclude that discounts should be offered to each retail jurisdiction with low system densities, and that it is illogical that Congress would intend for the LDD to be denied to a ratepayer based simply on whether his or her utility had operations in other states with higher densities and those higher densities provide no benefit to a ratepayer living in a low density region. *Id.*

NRU, on the other hand, argues that PacifiCorp's proposal would violate the Northwest Power Act. NRU Brief, WP-02-B-NI-02, at 22-23. NRU argues that section 7(d)(1) of the Northwest Power Act authorizes the Administrator to implement an LDD for "customers" with low system densities. *Id.* NRU argues that there is no reference in the Act to customers that have low densities in a portion of their system, nor is there the slightest hint in the Act, the legislative history, or in any BPA interpretation of the Act over the past 20 years that this provision was intended to be implemented on a state-by-state basis within the Northwest. *Id.* NRU argues that while the Northwest portion of a utility's service territory has been allowed to qualify for LDD benefits, even that program has never been implemented on a state-by-state basis; rather, the entire Northwest service territory of the utility has always been considered as a whole. *Id.* PacifiCorp's and NRU's arguments must be addressed by an examination of the Northwest Power Act and its legislative history.

PacifiCorp is a customer and purchaser of power from BPA. Pacific Power & Light and Utah Power & Light (UP&L) are simply business names of a single utility, PacifiCorp. BPA's GRSPs have required the determination of the LDD to be calculated using data based on "the Purchaser's entire electric utility system in the Pacific Northwest (PNW)." Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 99.

The Northwest Power Act supports the requirement that eligibility for the LDD is based on a customer's entire system within the region. Section 7(d)(1) of the Northwest Power Act provides BPA the discretionary authority to establish and implement the LDD:

> In order to avoid adverse impacts on retail rates of the Administrator's customers with low system densities, the Administrator shall, *to the extent appropriate*, apply discounts to the rate or rates of such customers.

16 U.S.C. §839e(d)(1) (emphasis added).

The statutory language "to the extent appropriate" grants the Administrator great discretion in determining eligibility for the LDD. Even ignoring this discretion, however, the language of the Northwest Power Act is quite clear. The Northwest Power Act allows the Administrator to apply discounts to the rates of customers with low system densities. PacifiCorp acknowledges that the literal language of the statute may well refer to BPA's utility customers. PacifiCorp Brief, WP-02-B-PL-01, at 6. Under the plain meaning of the Act, the LDD is applied to the customer as a whole and not some part of a customer. *See* NRU Brief, WP-02-B-NI-02, at 22-23. Notably, the statutory language also references "low *system* densities." The plain meaning of this language is that the customer's entire system must be reviewed in determining eligibility for the LDD. PacifiCorp is a single customer. PacifiCorp has a large integrated system within the PNW region. For these reasons, PacifiCorp's entire system within the region must be used in determining eligibility for the LDD. This conclusion is also consistent with the legislative history of the Northwest Power Act.

The legislative history of the Northwest Power Act demonstrates that Congressional intent in establishing the LDD was to benefit rural electric cooperatives with high distribution costs. The purpose of the LDD is described in the report of the House Committee on Interior and Insular Affairs:

> Section 7(d)(1) permits BPA to offer rate discounts to customers with low system densities such as rural electric cooperatives with high distribution costs resulting from sparsely populated service areas.

H.R. Rep. 976, Pt. I, 96th Cong., 2d Sess. 52 (1980).

The report of the House Committee on Interstate and Foreign Commerce similarly provides:

> Section 7(d) permits the Administrator to apply constraints to the rates of customers with low system densities. This is intended to afford greater equity to consumers of small rural co-ops which have high distribution costs due to difficult terrain, remote service areas, or other factors.

H.R. Rep. 976, Pt. II, 96th Cong., 2d Sess. 69 (1980).

An immense utility such as PacifiCorp can be eligible for the LDD if it meets the LDD criteria, but those criteria must be based on the utility's entire regional system. PacifiCorp argues that in the REP, BPA recognizes that benefits must be based on an Average System Cost (ASC) that is calculated on a state-by-state basis, based on the costs that are actually used in the determination of retail rates within each state. PacifiCorp Brief, WP-02-B-PL-01, at 4. In its rebuttal testimony, BPA acknowledged that PacifiCorp correctly noted that Residential Exchange benefits are determined on a state-by-state basis, based on a comparison of the utility's ASC with BPA's PF Exchange rate. Gustafson *et al.*, WP-02-E-BPA-48, at 8. The REP, however, is a different program than the LDD. Compare 16 U.S.C. §839c(c) with 16 U.S.C. §839e(d)(1). Simply because a program established in the Northwest Power Act determines benefits on a state-by-state basis based on the utility's costs in each state does not require that the LDD be applied in the same manner. One must review the nature and intent of the LDD to determine its proper application. Utility divisions are not separate utility customers but rather are divisions of a single utility customer. While the REP may be implemented based on state retail ratemaking jurisdictions, the LDD applies to utility customers, not divisions of utility customers. The issue is not whether a utility has different divisions serving different service territories, but whether the service territories are served by different utility customers. PacifiCorp wishes to impose the REP upon the determination of eligibility for the LDD. To the contrary, however, the LDD is provided to customers based only on each customer's entire regional system. While the REP may distinguish among divisions and portions of service territories, the same standards do not apply to the LDD, which looks at a customer's entire system within the region in all state jurisdictions for all divisions. For purposes of LDD determination, PacifiCorp is the purchaser for all power it purchases from BPA, not any PacifiCorp division.

In its brief on exceptions, PacifiCorp notes BPA's argument that "under the plain meaning of the [Northwest Power] Act, the LDD is applied to the customer as a whole and not some part of a customer . . . ." PacifiCorp Ex. Brief, WP-02-R-PL-01, at 2. PacifiCorp also notes that in referring to the statutory language referencing "low system densities," BPA concludes that "the plain meaning of this language requires consideration of a customer's 'entire system,' in determining eligibility for the LDD." *Id*. PacifiCorp argues that nowhere in the Northwest Power Act is the term "system" defined in reference to the statutory language referring to "low *system* densities." *Id*. PacifiCorp also argues that "system" does not have a single unambiguous meaning or even a plain meaning in the statutory context. *Id.* at 2-3. PacifiCorp is correct that the Northwest Power Act does not expressly define the term "system." However, BPA believes that the term "system" does have a plain meaning in the statutory context of the LDD. As noted previously, section 7(d)(1) of the Northwest Power Act refers to "the Administrator's *customers* with low system densities." 16 U.S.C. §839e(d)(1) (emphasis added). BPA believes that the logical meaning is that the statute is referring to an entire customer and thus the customer's entire system. PacifiCorp argues that it is only through legislative history that one learns the concern Congress is addressing is "high distribution costs." *Id*. Therefore, PacifiCorp argues that it is more reasonable to consider distribution system on a state-by-state basis where retail rates are calculated on that basis rather than to assume otherwise. *Id*. While it is true that the legislative history of the Northwest Power Act refers to "high distribution costs," it also consistently refers to "*small rural co-ops* which have high distribution costs due to difficult terrain, remote service areas, or other factors" and to "*rural electric cooperatives* with high distribution costs resulting from sparsely populated service areas." H.R. Rep. 976, Pt. I, 96th Cong., 2d Sess. 52 (1980) (emphasis added); H.R. Rep. 976, Pt. II, 96th Cong., 2d Sess. 69 (1980) (emphasis added). Such small rural cooperatives would have the LDD applied to their entire cooperative and their entire system. While multistate utilities would still be eligible for the LDD, they must similarly qualify on their entire utility and their entire system. BPA believes it would not be appropriate to permit eligibility for the LDD based on state-by-state jurisdictions of a customer.

PacifiCorp also argues that the Northwest Power Act does not compel the limitation on eligibility for the LDD proposed by the Administrator. PacifiCorp Ex. Brief, WP-02-R-PL-01, at 3. PacifiCorp argues that the explicit directive of Congress is that the Administrator apply discounts "[i]n order to avoid impacts on retail rates of the Administrator's customers with low system densities." *See* 16 U.S.C. §839e(d)(1). *Id*. PacifiCorp argues that this directive is more appropriately implemented by designing a program that makes the benefits of discounted Federal power to all retail customers that pay rates based on high distribution costs. *Id*. PacifiCorp argues that only by offering the discount to each retail jurisdiction with high distribution costs can the Administrator ensure that Congressional intent is carried out with respect to multistate utilities. *Id*. First, the statutory directive is that "[i]n order to avoid adverse impacts on retail rates of the Administrator's customers with low system densities, the Administrator shall, *to the extent appropriate*, apply discounts to the rate or rates of such customers."

16 U.S.C. §839e(d)(1) (emphasis added). As noted above, BPA believes that the Act allows multistate utilities to be eligible to receive the LDD, provided they meet the applicable criteria. These criteria, however, allow only *customers* with low density *systems* to receive the LDD. In the case of a large multistate utility, the utility may still receive the LDD, it must simply do so by establishing a low system density for its entire service territory. In this manner, Congressional intent is satisfied because the LDD is available for multistate utilities that have low density systems for their entire system based on that system's overall high distribution costs.

PacifiCorp also notes that BPA questioned whether a large multistate utility might have certain economies of scale that would offset high distribution costs. PacifiCorp Brief, WP-02-B-PL-01, at 7. PacifiCorp notes that BPA did not investigate this proposition and did not consider whether preference customers might have cost advantages over IOUs that would offset their high distribution costs. *Id.* PacifiCorp argues that BPA should not look at these criteria if not set forth in the Northwest Power Act. *Id.* NRU argues that BPA pointed out that large multistate utilities such as PacifiCorp may realize economies of scale, which may offset higher distribution costs in its state-by-state distribution systems. NRU Brief, WP-02-B-NI-02, at 23. In BPA's rebuttal testimony, BPA stated that "[a] utility might have low retail rates despite higher than normal distribution costs. BPA would like to review the parties' testimony and briefs on these issues to make an informed decision." Gustafson *et al.*, WP-02-E-BPA-48, at 7-8. BPA therefore intended to review the parties' rebuttal testimony and briefs on this issue to determine whether there was evidence that this was a factor that should be considered. BPA found that the parties' rebuttal testimony did not address this issue, and the briefs provided no new evidentiary information. Because there is an insufficient record in the current rate case to make a determination on this issue, BPA will not consider this issue in determining eligibility for the LDD. This issue may be addressed in future rate cases. BPA, however, disagrees with PacifiCorp's contention that BPA should not look at criteria if not set forth in the Northwest Power Act. BPA is using the criteria set forth in the Northwest Power Act, but in determining the applicability of those criteria, it is appropriate to review evidence regarding such factors. In this case, the statute refers to "*adverse impacts on retail rates* of the Administrator's customers with low system densities." 16 U.S.C. §839e(d)(1). In the event there are factors that offset adverse impacts on retail rates, such factors may be reviewed in future proceedings.

NRU argues that BPA should reject PacifiCorp's proposal for state-by-state LDD eligibility. NRU Brief, WP-02-B-NI-02, at 20-23. NRU argues that the Subscription ROD precludes increases in LDD costs. *Id.* at 21. In developing the Subscription Strategy, NRU argues that BPA deferred its proposal to eliminate the K/I ratio from the LDD but rejected any increase in the 7 percent cap, noting that "BPA has indicated its intent to control future LDD costs . . . [A]ny increase in the LDD would be contrary to this effort." *Id.* NRU also argues that PacifiCorp should have raised its proposal during the Subscription process. *Id.* at 21-22. NRU also argues that it would be unfair for BPA to create a new LDD benefit for PacifiCorp while telling other utilities that it wants to cap or reduce benefits. *Id.* at 22. NRU misinterprets the Subscription ROD. BPA's statements in the Subscription Strategy and ROD were not final rate decisions, which can be made only in a section 7(i) hearing process. 16 U.S.C. §839e(i). BPA's discussions on rate issues in the Subscription process were limited to discussions of what might be included in BPA's initial proposal, which then might be subject to change in the formal hearing. Therefore, the Subscription ROD does not preclude the adoption of PacifiCorp's proposal if BPA determined that such proposal were appropriate.

PacifiCorp argues that the LDD should be available to the RL and PF Exchange Subscription rates. PacifiCorp Brief, WP-02-B-PL-01, at 7-9; PacifiCorp Ex. Brief, WP-02-R-PL-01, at 3-4. PacifiCorp argues that the Subscription Strategy expressly provided for parity between the PF and RL rate. *Id.* The Subscription Strategy states that "These [IOU] sales will be at a rate approximately equal to the PF Preference rate, subject to establishment in BPA's rate case and consistent with BPA's rate directives." *Id.* PacifiCorp also argues that BPA witness Leathley acknowledged that in comparing the rate charged to two different customer classes, one must consider rates, terms and conditions of each offer to determine whether customers will pay approximately the same rate; thus, unless the RL rate receives the LDD, it will not be approximately equal to the PF Preference rate. PacifiCorp Brief, WP-02-B-PL-01, at 8; PacifiCorp Ex. Brief, WP-02-R-PL-01, at 4.

PacifiCorp has misinterpreted BPA's Subscription Strategy. First, BPA's statements in the Subscription Strategy and ROD were not final rate decisions, which can be made only in a section 7(i) hearing process. 16 U.S.C. §839e(i). BPA's discussions on rate issues in the Subscription process were limited to discussions of what might be included in BPA's initial proposal, which then might be subject to change in the formal hearing. The Subscription Strategy did not specifically address, much less conclude, whether the LDD would apply to the RL rate. Significantly, BPA's statement noted that the RL rate was "subject to establishment in BPA's rate case and consistent with BPA's rate directives." This clearly recognized the possibility that the LDD might be determined in the rate case not to apply to the RL rate. It also recognized the possibility that BPA's rate directives might not require or permit the application of the LDD to the RL rate. Furthermore, BPA's general statement that IOU settlement sales will be at a rate "approximately equal to the PF Preference rate" (subject to the above-noted conditions) does not require the application of the LDD to the RL rate. The Subscription Strategy spoke in general terms about the level of the RL and PF Preference rates. The Subscription Strategy did not say that the RL rate would be eligible for the same rate adjustment features of the PF Preference rate. Indeed, this is consistent with the fact that the RL rate is not subject to a number of charges that apply to the PF Preference rate, such as the TAC, TACUL, SUMY, and other charges. Furthermore, in any event, an RL rate without the LDD would still be approximately equal to the PF Preference rate.

BPA believes it is inappropriate to apply the LDD to the RL rate for additional reasons. It is necessary to understand the nature of the sales governed by the RL and PF Exchange Subscription rates. Gustafson *et al.*, WP-02-E-BPA-48, at 9-10. In BPA's Subscription Strategy, BPA proposed to offer regional IOUs the equivalent of 1,800 aMW of Federal power, in the form of power deliveries or monetary payments, to settle the utilities' rights to participate in the REP. *Id.* The RL and PF Exchange Subscription rates apply only to power sales and monetary benefit calculations under the proposed settlements. *Id.* In a separate administrative proceeding, BPA is developing a methodology for the allocation of the 1,800 [1,900] aMW benefits among the regional IOUs. *Id.* BPA is also taking public comment on whether the settlement amount should be increased from 1,800 aMW to 1,900 aMW. *Id.* As noted above, REP benefit calculations are based on the comparison of a utility's ASC with BPA's PF

Exchange rate. *Id.* These determinations are made for each individual exchanging utility. *Id.* These determinations do not affect the Residential Exchange benefits provided to other exchanging utilities. *Id.* Similarly, providing the LDD to an exchanging utility does not affect the Residential Exchange benefits provided to other exchanging utilities. *Id.* This is not true with regard to settlement benefits if the LDD were applied to the RL and PF Exchange Subscription rates. *Id.*

BPA's settlement proposal allocates a specific amount of settlement benefits among a limited number of IOUs. *Id.* BPA solicited the views of the PNW state public utility commissions in order to develop its allocation proposal. *Id.* The commissions proposed specific amounts of the total benefits for each IOU, including specific amounts for each of PacifiCorp's three state jurisdictions. *Id.* BPA believes that the commissions' proposal was very difficult to develop. *Id.* BPA has no evidence that the commissions took into account the possible increase in benefits to PacifiCorp's Idaho jurisdiction if the LDD were applied to the RL and PF Exchange Subscription rates. *Id.* If the LDD applied to those rates, only PacifiCorp would pay a lower rate for power provided under the proposed settlement agreements, and only PacifiCorp would receive an increased amount of monetary benefits due to a lower rate that, when compared with BPA's five-year market forecast, is used to calculate monetary benefits under the proposed settlements. *Id.* While the settlement amounts contained in the allocation proposal for other utilities would not be decreased, those utilities' percentages of the total settlement benefits would be reduced. *Id.*

In addition, on cross-examination BPA's witness noted additional reasons why the LDD should not apply to the RL and PF Exchange Subscription rates. BPA's witness stated that it would be inappropriate to apply the LDD to the RL rate for PacifiCorp's southern Idaho territory because BPA's initial proposal did not include LDD benefits going to any of the IOUs, and therefore when the state commissions developed a proposed allocation of settlement benefits among the IOUs, they would have not factored in the LDD in their calculations. Tr. 1520. In addition, BPA's witness noted that the commissions' proposed allocation to the UP&L division of PacifiCorp was practically the whole amount of its residential and small farm load. *Id.* To also provide the LDD to that load would have given preferential treatment to PacifiCorp's southern Idaho customers.

In its brief on exceptions, PacifiCorp argues that, while BPA points out that if the LDD were applied to the RL or PF Exchange Subscription rate, PacifiCorp would pay a lower rate for power to serve southern Idaho than other RL or PF Exchange Subscription customers pay, but this is basically the same as BPA's preference customers with low density systems paying a lower rate for power than preference customers with higher density systems. PacifiCorp Ex. Brief, WP-02-R-PL-01, at 4. PacifiCorp also argues that "just as PacifiCorp's percentage share of the settlement benefits would rise if it qualifies for the LDD (and accepts a settlement offer), so too do preference customers qualifying for the LDD receive an increased percentage of federal power benefits as a consequence." *Id.* There is an important distinction that must be drawn between the RL and PF Exchange Subscription rates that apply to the proposed IOU Residential Exchange *settlements* and the PF Preference rate that applies to BPA's net requirements *sales* to preference customers. The PF Preference rate is a rate that BPA has applied for nearly 20 years for actual net requirements power sales to its preference customers.

The RL and PF Exchange Subscription rates, however, are rates that BPA is offering for the first time and for a single purpose: the settlement of the Residential Exchange Program. BPA's sales to preference customers are not limited to a defined amount of power. BPA's preference customers purchase power based upon their net requirements. In the proposed IOU settlements, however, there is a finite amount of benefits available to a limited number of utilities. In the Residential Exchange settlement proposal, BPA is attempting to treat all regional IOUs fairly. As noted previously, BPA's settlement proposal allocates a specific amount of settlement benefits among a limited number of IOUs. Gustafson *et al.,* WP-02-E-BPA-48, at 9-10. BPA solicited the views of the PNW state public utility commissions in order to develop its allocation proposal. *Id.* The commissions proposed specific amounts of the total benefits for each IOU, including specific amounts for each of PacifiCorp's three state jurisdictions. *Id.* BPA believes that the commissions' proposal was very difficult to develop. *Id.* BPA has no evidence that the commissions took into account the possible increase in benefits to PacifiCorp's Idaho jurisdiction if the LDD were applied to the RL and PF Exchange Subscription rates. *Id.* Because the RL and PF Exchange Subscription rates apply only to the proposed Residential Exchange settlement agreements, and because BPA wishes to implement the settlements in a manner that is fair for all regional utilities and state regulatory commissions, BPA believes it would be inappropriate to apply the LDD to the RL and PF Exchange Subscription rates and alter the virtual regional consensus regarding the allocation of the settlement benefits among the individual regional IOUs.

In summary, the RL and PF Exchange Subscription rates are special rates for a specific purpose--the implementation of the proposed settlement agreements. Gustafson *et al*., WP-02-E-BPA-48, at 10. It is inappropriate to apply the LDD to these rates and indirectly affect the proposed percentage allocation of benefits provided to the potential settling utilities. *Id.*

Decision

BPA will calculate the LDD based on a customer's entire electric utility system within the region. The LDD will not be applied to the RL-02 and PF Exchange Subscription rates.

Issue 11

Whether BPA should clarify the rate schedules to which the LDD applies.

Parties' Positions

PacifiCorp argues that BPA should apply the LDD to both the RL rate and the PF Exchange Subscription rate. PacifiCorp Brief, WP-02-B-PL-01, at 7-9.

BPA's Position

In its initial proposal, BPA identified the following rate schedules as eligible for the LDD: the PF Preference rate, the PF Exchange Program rate, the PF Exchange Subscription rate, the RL-02 rate, and the NR-02 rate. Gustafson and Thompson, WP-02-E-BPA-23, at 2-3. In its rebuttal testimony, BPA proposed that the LDD not apply to the RL-02 rate and the PF Exchange Subscription rate. Gustafson *et al.*, WP-02-E-BPA-48, at 9-10.

Evaluation of Positions

In the initial proposal, BPA stated that the LDD would be applied to specified power purchases under the PF Preference rate, the PF Exchange Program rate, the PF Exchange Subscription rate, the RL-02 rate, and the NR-02 rate. Gustafson and Thompson, WP-02-E-BPA-23, at 2-3. As discussed in the previous Issue, however, BPA has determined that it is not appropriate to apply the LDD to the RL-02 rate and the PF Exchange Subscription rate. The RL and PF Exchange Subscription rates are special rates for a specific purpose--implementation of the proposed settlement agreements. Gustafson *et al*., WP-02-E-BPA-48, at 10. It is inappropriate to apply the LDD to these rates and indirectly affect the proposed percentage allocation of benefits provided to the potential settling utilities. *Id.*

Decision

To clarify, the LDD shall apply only to the PF Preference rate, the PF Exchange Program rate, and the NR-02 rate.

10.13 Conservation and Renewables (C&R) Discount

BPA proposed the C&R Discount to create incremental efficiency gains and renewable energy supplies, and to provide incentives to continue the region's progress in low-income weatherization programs. Esvelt *et al*., WP-02-E-BPA-33, at 2. The C&R Discount is a line item reduction in the customer's monthly power bill. *Id*. at 5. The monthly discount will be set prior to the rate period based on the customer's Subscription power purchases. *Id*. The discount will be deducted as a dollar amount and will not affect calculation of other billing factors. *Id*. The amount of the C&R Discount is 0.50 mills/kWh of power purchases made from selected BPA rate schedules. *Id*. at 6.

Issue 1

Whether BPA should eliminate the incremental spending requirement under the C&R Discount.

Parties' Positions

PPC argues that BPA should eliminate the incremental spending requirement. PPC Brief, WP-02-B-PP-01, at 39-40. In its brief on exceptions, PPC claims that BPA unreasonably and arbitrarily rejected PPC'S recommendation to eliminate the incremental spending requirement. *See* Draft ROD, WP-02-A-01, at 10-88. BPA should reconsider and eliminate the incremental spending requirement of the C&R Discount. PPC Ex. Brief, WP-02-R-PP-01, at 8.

The DSIs argue that the Administrator should apply the C&R Discount to all conservation and renewables expenditures. DSI Brief, WP-02-B-DS-01, at 79. They claim that the Draft ROD's refusal to apply the C&R Discount to all conservation and renewables expenditures is arbitrary, capricious, and bad policy. DSI Ex. Brief, WP-02-R-DS-01, at 12.

Renewable Northwest opposes efforts to eliminate the incremental spending requirement. Renewable Northwest Brief, WP-02-B-RN-01, at 1.

NEC/SOS argue that BPA should require utilities to meet one of three specific tests to establish acceptable incremental investments that it recommended in its direct testimony. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 21.

BPA's Position

Incremental spending is intended to be a tool to measure the amount of the C&R Discount being spent on qualifying expenditures. Esvelt *et al*., WP-02-E-BPA-55, at 2. The utility will make its own decisions regarding the amount of its spending absent the C&R Discount and will determine its priorities on individual measures or projects. *Id*.

BPA evaluated and rejected the NEC/SOS recommended incremental spending proposal in BPA's rebuttal. *See* Esvelt *et al*., WP-02-E-BPA-55, at 6-7.

Evaluation of Positions

PPC argues that the incremental spending requirement is objectionable for several reasons. PPC Brief, WP-02-B-PP-01, at 39. PPC contends that incremental spending was first suggested by BPA in the spring of 1999 after the close of a public process. *Id*. PPC claims that it understood the use of the term "new" to apply singularly to "new renewable resources," but not to conservation resource expenditures. *Id*. PPC also argues that although BPA's Subscription Strategy ROD discussed that the C&R Discount would not be used to cover past investments, the Subscription ROD does not reflect the contemporaneous regional Subscription discussions. PPC's representatives participating in the Subscription proposal discussions do not recall even one discussion on this issue. *Id*. at 40. Finally, PPC argues that the incremental spending requirement decreases the flexibility available to BPA's public agency customers in designing conservation programs for their consumers. This would diminish the C&R Discount's value. *Id*.

The DSIs also oppose the incremental spending requirement and state that the discount should apply to all conservation and renewables expenditures. DSI Brief, WP-02-B-DS-01, at 79. The DSIs argue that the incremental requirement is inconsistent with the original policies underlying the recommendations of the Steering Committee to the Comprehensive Review. *Id*. at 78. In support of their position, the DSIs quote an argument made by NRU that "disqualifying otherwise qualified expenditures on the grounds that they are not 'incremental' would penalize the utilities that are presently making the most effort to implement conservation and renewable programs." *Id*.; *see* Saven, WP-02-E-NI-04, at 20. The DSIs argue that, similarly, the incremental investment is not consistent with the decision making progress of industrial consumers for whom investments are judged by management taking into account all of the costs and benefits known to exist at the time the decisions are made. DSI Brief, WP-02-B-DS-01, at 78. The DSIs are concerned that BPA might be tempted to discriminate between utilities and DSIs on the question of incremental investment. Waddington, WP-02-E-DS-05, at 5. The DSIs argue that customers should receive discounts on an equal basis for equal investments. DSI Brief, WP-02-B-DS-01, at 78. The DSIs note that BPA's willingness to expand its current exceptions to the incremental requirement to treat spending that qualifies under state mandated or state programs (whether the spending is by a DSI, a utility, or a utility's customer) ameliorates the problem of the incremental requirement somewhat and is a welcome step in the right direction. *Id*. at 79.

The parties' arguments are not persuasive. As cited by the PPC, BPA's Power Subscription Strategy ROD at 138 discussed the concern that the "C&R Discount not be used to cover the conservation and renewable resource investments that are already in power customers' plans." BPA's expert witnesses testified that BPA's decision to include incremental spending in the C&R Discount was publicly known prior to its proposal in this rate case. Esvelt *et al*., WP-02-E-BPA-55, at 3. BPA had a strong desire that the C&R Discount amount be supplemental to the amount power customers were planning to spend on these types of activities, *e.g.,* incremental conservation and renewable resource investments. *Id*. PPC opposes the incremental spending requirement because of concern that it would impact local control. Fey *et al*., WP-02-E-PP-05, at 4-5. The ability of customers to self-certify should alleviate some the concerns raised by the PPC regarding implementation of the C&R Discount. The utility will make its own decisions regarding the amount of its spending absent the C&R Discount and will determine its priorities for spending on individual measures or projects. Esvelt *et al*., WP-02-E-BPA-55, at 3.

Renewable Northwest argues that, even with the incremental investment requirement, utilities can still make investments in conservation and renewable resources that cater to their own service territories and are consistent with the needs of their own end-use customers. Renewable Northwest Brief, WP-02-B-RN-01, at 2. BPA agrees. BPA is not persuaded by PPC's statement that the incremental spending requirement will diminish the value of the C&R Discount. Making available a rate discount to customers purchasing firm power in Subscription is appealing, because it will allow utilities to design and implement conservation or renewables programs to respond to local circumstances, interests, and needs. Esvelt *et al*., WP-02-E-BPA-33, at 5.

The DSIs argue that the incremental spending requirement is inconsistent with the Comprehensive Review. DSI Brief, WP-02-B-DS-01, at 77. The concept for the C&R Discount is related to the Comprehensive Review's recommendation to Northwest states to sustain conservation and renewable resources development and low-income weatherization. Esvelt *et al*., WP-02-E-BPA-33, at 4. The Comprehensive Review does not, however, dictate how BPA is to design and offer the C&R Discount.

The DSIs also are concerned that the incremental spending requirement is not consistent with the decisionmaking process of industrial consumers. Waddington, WP-02-E-DS-05, at 6. While BPA is certainly sympathetic to its customers' decisionmaking processes, BPA has decided upon a mechanism that can be uniformly implemented. The specific charge per MWh applied to a customer's forecasted Subscription power purchases will allow it to prepare fixed annual budgets for conservation and renewables expenditures that are equal to its eligibility for the C&R Discount. Esvelt *et al*., WP-02-E-BPA-33, at 6. BPA expects local utility management to self-certify C&R Discount expenditures in the same way they approve budgets and forecasts. Esvelt *et al*., WP-02-E-BPA-55, at 4. The customer is in a position to approve a certification statement based on its knowledge of past expenditures and approved annual budgets. *Id*. BPA objects to the DSIs' reference or implication that BPA might be tempted to use this type of mechanism to discriminate between utilities and DSIs. BPA will employ the same criteria to all customers. Finally, BPA would like to correct a misstatement in the DSIs' initial brief. The DSIs view BPA's willingness to expand its current exemptions to the incremental requirement to treat spending that qualifies under state mandated or state programs (whether the spending is by a DSI, a utility, or a utility's customer) as a "welcome step in the right direction" to help ameliorate the problem of the incremental requirement. DSI Brief, WP-02-B-DS-01, at 79. The DSIs reference testimony of BPA's witness. Tr. 1636. BPA would like to clarify that BPA does not intend the exemption for purposes of state and municipal programs to include a "utility's customer." On redirect, BPA's witness corrected his testimony to make it clear the exemption applies to only a BPA customer. Tr. 1646.

PPC argues that, if BPA implements the incremental spending requirement, self-certification, and an exemption for those utilities who spend 3 percent or more of their revenues on public purposes is necessary. PPC raised the same issue in its direct case. BPA responded that it agreed that a utility which spends at least 3 percent of its retail revenues on qualifying measures should be exempt from the requirement that it certify that its expenditures are incremental. Esvelt *et al*., WP-02-E-BPA-55, at 3-4. PPC raises concern that BPA not adopt the stringent qualification standards for the incremental spending requirement proposed by the NEC in Weiss, WP-02-E-NA-01, at 22. PPC Brief, WP-02-B-PP-01, at 40. These incremental qualification standards would require utilities that do not invest more than 3 percent of retail sales in C&R Discount eligible activities to increase spending over a average amount based on the previous three years or any funding in excess in 1 percent of retail revenues.

In its brief on exceptions, NEC objects to BPA's conclusion in the Draft ROD that discounted the NEC's proposed recommendation for incremental spending. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 21. NEC/SOS claim that BPA's reasons for rejecting its proposal "make little sense and are contradictory." *Id.* NEC/SOS take out of context BPA's rebuttal testimony to argue that BPA admits that the NEC/SOS proposal "may have the advantage of being measurable." *Id*. The entire sentence of the BPA witnesses' testimony shows a well-reasoned decision regarding the NEC/SOS proposal. After reviewing and evaluating the NEC/SOS proposal, BPA's witnesses stated: "Although the first two paths suggested for determining whether a utility's investments in conservation and renewables are incremental may have the advantage of being measurable, they may also have unintended consequences." Esvelt *et al*., WP-02-E-BPA-55, at 6.

NEC/SOS now challenge BPA's rebuttal without having raised their arguments in their initial brief. NEC/SOS argue that BPA simply mischaracterizes the NEC/SOS proposal in order to discount it. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 22. In support of its recommended proposal, NEC/SOS counter that utilities might reduce their current spending levels in order to demonstrate an increase during the rate period. *Id*. at 21. NEC/SOS claim that this is equally true about BPA's own proposal, so it must not be given any more weight than NEC/SOS's. *Id*. NEC/SOS note that BPA states that the 1 percent path might be onerous to customers currently spending very little on conservation and renewables. *See* Esvelt *et al*., WP-02-E-BPA-55, at 7; NEC/SOS Ex. Brief, WP-02-R-NA/SA-01 at 21. NEC/SOS claim that their proposal allows these utilities to choose the other path, where their incremental spending is measured against previous levels, and allows those customers to qualify under that path. *Id*. at 21-22. BPA disagrees that it mischaracterized the NEC/SOS proposal in order to discount it, as alleged by NEC/SOS. The NEC/SOS attempt to rehabilitate its previous testimony is not persuasive. BPA's decision not to adopt the NEC/SOS proposed recommendation is well-reasoned and supported by substantial evidence.

BPA maintains that the first path could lead utilities to actually decrease their spending levels during the 2000-2001 time period in order to demonstrate an increase in spending during the rate period. Esvelt *et al*., WP-02-E-BPA-55, at 6-7. Using an earlier period, such as 1997-1999, would not work, because BPA's traditional conservation programs were operating during that time. *Id*. The second path proposes an arbitrary level of 1 percent as a base for determining incremental investments. *Id*. This level may have the unintended consequence of discouraging many utilities from increasing their C&R investments and participating in the C&R Discount at all. *Id*. BPA still believes that the NEC/SOS proposed recommendation may have unintended consequences which are not acceptable and contrary to BPA's stated desire to provide local control and administration of future conservation and renewable development activities. Esvelt *et al*., WP-02-E-BPA-55, at 6-7.

BPA does not agree that it is arbitrary, capricious and, as alleged by the DSIs in their brief on exceptions, bad policy to reject any parties' recommendation. PPC Ex. Brief, WP-02-R-PP-01, at 8; DSI Ex. Brief, WP-02-R-DS-01, at 12. BPA's decisions are based on the evidence in the record and are well reasoned and analyzed.

Decision

BPA will not eliminate the incremental spending requirement under the C&R Discount; the incremental spending requirement will measure the amount of the C&R Discount being spent on qualifying expenditures.

Issue 2

Whether BPA should modify the C&R Discount to allow the continuation of funding for low-income weatherization programs.

Parties' Positions

NEC and SOS propose that BPA modify the C&R Discount in a manner that would allow for the guaranteed future funding of low-income weatherization programs. NEC/SOS Brief, WP-02-B-NA/SA-01, at 33. The NEC direct testimony criticized how BPA's proposed C&R Discount program dealt with low-income weatherization. Weiss, WP-02-E-NA-01, at 23. NEC/SOS provided details of their recommendation that BPA budget $4 million annually of C&R Discount funds to state low-income weatherization programs. NEC/SOS Brief, WP-02-B-NA/SA-01, at 34, citing WP-02-E-NA-06. NEC and SOS urge BPA to replace its proposal with that of NEC. *Id*. at 35.

In their brief on exceptions, NEC/SOS note that they believe the decision in the Draft ROD is unclear. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 22. NEC/SOS argue that the decision in the Draft ROD is not a decision, and that they are unfairly precluded from supporting or opposing BPA's decisions based on the record or being able to correct the record regarding BPA's decision. *Id*. NEC/SOS go on to "correct one assumption" BPA makes, and that is the assumption about "local control," which BPA believes is increased by allowing its customers to direct the funds rather than what BPA characterizes as the "centralized funding" approach NEC/SOS proposed. *Id*. at 23.

<u>BPA's Position</u>

A central goal of the C&R Discount is to promote local control and management of conservation and renewable programs. Esvelt *et al*., WP-02-E-BPA-55, at 8. Central allocation of a portion of the C&R Discount to the states for low-income weatherization would result in a loss of local control. *Id*. at 7. BPA also stated this concern in cross-examination. *See* Tr. 1627. Central allocation of a portion of the C&R Discount to states for low-income weatherization would negatively impact utilities that wished to make all their investments in, for example, renewables. Tr. 1628.

<u>Evaluation of Positions</u>

BPA does not agree that the Draft ROD decision is unclear; however, BPA does recognize the need to clarify the evaluation of the parties' position in the Draft ROD regarding the funding of low-income weatherization programs. The NEC/SOS brief on exceptions targets only the "local control" aspect of BPA's decision because, as claimed by NEC/SOS, "[I]t is unclear, . . . what the Draft Decision actually says." NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 22. In their initial brief, NEC/SOS urged BPA to replace its proposal with NEC's recommendation. NEC/SOS Brief, WP-02-B-NA/SA-01, at 33. NEC's direct testimony criticized how BPA's proposed C&R Discount program dealt with low-income weatherization. Weiss, WP-02-E-NA-01, at 23. NEC proposed that BPA budget $4 million annually of C&R Discount funds for state low-income weatherization programs. WP-02-E-NA-06. NEC/SOS urged BPA to replace its proposal with that of NEC. NEC/SOS Brief, WP-02-B-NA/SA-01, at 35. BPA opposed NEC's recommended improvements for backup funding of low-income weatherization, because they are incompatible with BPA's goals for local control and management of the C&R Discount. Esvelt *et al*., WP-02-E-BPA-55, at 8. BPA does not accept the NEC proposal for central allocation of a portion of the C&R Discount to the states for low-income weatherization, also because of the loss of local control. Tr. 1628.

NEC/SOS contend that BPA has presented no evidence in this proceeding to demonstrate that the "local control" of DSIs and utilities is superior in any way to that of the community action agencies which currently run these programs and would continue to do so under NEC's proposal. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 23. NEC/SOS claim that it is arbitrary and capricious for BPA to use the concept of local control as a factor in choosing among alternatives without providing a meaningful definition and evidence on the record to support its conclusion. *Id*. at 24.

BPA recognizes the potential damage to current programs caused by funding uncertainties inherent in the proposed utility-by-utility funding mechanism. Tr. 1628-29. BPA has reviewed centralized funding, as discussed in cross-examination, to preserve the benefits of the existing low-income weatherization infrastructure. Tr. 1629-30. Centralized funding would reduce BPA financial risk liabilities and would provide continuous funding for state-run low-income weatherization activities. Tr. 1628-29. To implement this option, BPA has evaluated the amount of funding required to adjust existing budgets sufficient to continue the existing state low-income weatherization activities.

While recognizing the advantages and disadvantages of centralized funding, BPA favors the degree of local control provided by its proposed C&R Discount approach. NEC/SOS are mistaken in its understanding that BPA's decision is based solely on the concept of local control. BPA's decision is based upon reasoned analysis and evidence presented on the record throughout this rate proceeding. NEC/SOS are remiss in their failure to consider the entire record. In short, BPA stated in direct testimony that BPA made the policy decision to review regional C&R Discount annual spending levels for low-income weatherization. Esvelt *et al*., WP-02-E-BPA-55, at 8. BPA expects regional spending to amount to $4 million for low-income weatherization. *Id*. If this level is not reached, BPA will make direct investments in low-income weatherization to make up the shortfall. *Id*.

Decision

BPA will consider an alternative outside of the C&R Discount to continue funding low-income weatherization programs. BPA has already stated it would make good the funding.

10.13.1 Conservation Augmentation

Issue

Whether BPA has properly calculated the amount of conservation augmentation required to meet the NWPPC's current cost-effective conservation target.

Parties' Positions

NEC/SOS argue that conservation for augmentation is incorrectly calculated and should not include the C&R Discount, because it does not meet the Council's Plan. NEC/SOS Brief, WP-02-B-NA/SA-01, at 32. NEC/SOS argue that BPA is required to acquire 150 aMW from BPA-sponsored conservation activities. *Id*. NEC/SOS also argue that the correct number is 166 aMW in BPA's utilities' territories plus another 140 aMW for BPA's share of the DSI load, or a total of 306 aMW, not 150. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01 at 25**.**

PPC supports BPA's overall conservation goal of 150 aMW; it includes demonstrable savings implemented through the C&R Discount Program. PPC Brief, WP-02-B-PP-01, at 41.

BPA's Position

This is a new issue not raised previously by any parties to this proceeding. BPA has no position on this issue on the record. NEC/SOS's introduction of new conservation target numbers in their brief on exceptions is clearly unsupported by the record, nor does it comport with NEC/SOS's position as presented in their initial brief. As such, NEC's new argument is in violation of §1010.13 of the rules of procedure that govern this proceeding.

Evaluation of Positions

NEC/SOS argue that at the 150 aMW target is incorrect because it does not contain the amount of cost-effective conservation that the NWPPC has identified in BPA's load base. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 25. NEC/SOS claim that the number is now 166 aMW for utilities and 140 aMW for DSI load, for a total of 306 aMW. *Id*. NEC/SOS previously supported the 150 aMW target by stating in their initial brief, "Since the 150 aMW target the Council established was Bonneville's load share of the total cost-effective conservation available in the region, BPA should not count conservation which does not result in a reduction of the agency's load toward the 150 aMW target." NEC/SOS Brief, WP-02-B-NA/SA-01 at 33.

NEC/SOS's brief on exceptions introduces new conservation target numbers that are clearly unsupported by the record and which do not comport with NEC/SOS's position as presented in their initial brief. NEC/SOS make this assertion without offering any evidentiary support underlying their newest claim. Putting aside the fact that NEC/SOS do not provide any evidence to support their claim, no parties in this proceeding, including BPA, have had the opportunity to review, analyze, or offer evidence or testimony to rebut NEC/SOS's claim. NEC/SOS's new argument is in violation of §1010.13 of the rules of procedure that govern this proceeding. Without some factual support in the record to support rejecting the current conservation target of 150 aMW and the assumptions that underlie it, it would be unreasonable for BPA to do so.

BPA stated its plans to implement a total of 150 aMW from all BPA-sponsored conservation activities over the rate period. Oliver *et al*., WP-02-E-BPA-45, at 8. BPA included an annual acquisition target of 12 aMW of conservation resources, on an annual basis, in its augmentation plans. *Id.* The 12 aMW target was set based on the current 1998 Northwest Conservation and Electric Power Plan. *Id.*

NEC/SOS note that BPA is allowing customers that buy only a part of their power from BPA ("partial requirements customers") to qualify for the discount based on conservation programs carried out in their entire territory. NEC/SOS Brief, WP-02-B-NA/SA-01, at 32. In its brief on exceptions, NEC/SOS contend that BPA mischaracterizes NEC/SOS's point. NEC/SOS Ex. Brief, WP-02-R-NA/SA-01, at 25. NEC/SOS's point is "partial requirements may claim credit under the C&R Discount for conservation which does not reduce BPA's load." *Id*. They point out that "those conserved MWs which do reduce BPA's load should not counted . . . ." *Id*. NEC/SOS claim, without any evidence in the record to support their claim, that "[a] substantial portion of BPA's power will we [sic] sold to partial requirements customers that have significant loads served from other resources than Bonneville." *Id*. NEC/SOS contend that conservation expenditures, and their resulting load reductions, made by customers purchasing only a portion of their requirements power from BPA may not result in a reduction in their power purchased from BPA because these reductions are likely to result in reductions in purchases from higher-priced resources. *Id.* at 33. NEC/SOS claim that doing a correct calculation of the conservation acquired from partial requirements customers under the C&R Discount would result in raising "the amount of conservation BPA must acquire under its augmentation program." *Id.* at 39.

The NEC/SOS argument is not supported by any evidence in the record. Rather, NEC/SOS make broad conclusions based on generalizations of fact. NEC/SOS asked a hypothetical question of BPA's witnesses regarding the application of the C&R Discount to partial requirements customers. Tr. 1632. The full testimony of BPA's witness is as follows:

> A. (Mr. Esvelt) I think the answer is yes, with two qualifications. One is that of course the utility must be making expenditures on eligible measures. And the second qualification is that the C&R Discount of course establishes a maximum amount of discount dollars that are available to that utility.

Tr. 1632.

BPA's witness answered that a partial requirements customer is eligible for the C&R Discount. With regard to NEC/SOS's statement that BPA should not count conservation which does not result in a load reduction, BPA has neither testified, nor is there evidence in the record, as to how the conservation achievement of individual utilities resulting from the C&R Discount will be combined to meet the 150 aMW target. As noted by NEC/SOS, BPA currently sells power to some customers that use their own resources. Sections 5(b)(1)(A) and (B) of the Northwest Power Act expressly provide that BPA's obligation to serve customers purchasing for their regional firm power load shall be reduced by the amount of resources customers use to serve their regional loads. Sections 4 and 6 of the Northwest Power Act also direct BPA to seek and achieve conservation. These provisions do not limit the Administrator from achieving conservation due to the purchasing or operational basis of any BPA customer. *See, generally,* 16 U.S.C. §839b and §839f. NEC/SOS make an additional unsupported conclusion when they state, "these utilities have a large incentive to use any conservation-induced load reductions to reduce their take from higher priced resources." NEC/SOS Brief, WP-02-B-NA/SA-01, at 33. The record does not provide evidence as to the specific loads of customers that will purchase on a partial requirements basis or as to the amount of power such customers may buy from BPA. Nor does the record provide evidence as to the price of the resources NEC claims that partial requirements customers will reduce as a result of the C&R Discount. For these reasons, BPA cannot accept the NEC/SOS position with respect to the calculation of the 150 aMW as it pertains to the C&R Discount.

Decision

BPA has properly calculated the amount of conservation augmentation required to meet the NWPPC's current cost-effective conservation target.

10.14 Green Energy Premium

Previously, BPA provided customers the opportunity to purchase Environmentally Preferred Power (EPP) through surplus firm power sales under the FPS-96 rate schedule at negotiated prices. Because the continued availability of surplus firm power that is sold under the FPS-96 rate schedule is uncertain in the next rate period, BPA developed the Green Energy Premium (GEP) to meet future demand by customers interested in purchasing EPP under Subscription firm power sales contracts. BPA included the GEP in the initial proposal to provide a method for customers to purchase EPP during the FY 2002-2006 rate period. Esvelt *et al.,* WP-02-E-BPA-33, at 12.

The GEP is a pricing approach applied to customers that choose to designate any portion (0 to 100 percent) of their Subscription power purchases as EPP. Customers selecting the GEP will continue to receive system power deliveries from BPA. In addition, these customers will receive EPP production documentation showing that their GEP purchases have resulted in the delivery of EPP to the system. *Id.*

GEP purchases require a customer to commit a portion of its net requirements, served at a posted firm power rate, to service at the posted rate plus the GEP. This is done by designating any portion of the customer's Subscription power purchases as EPP. The GEP will be available to purchases made under the PF-02, IP-02, RL-02, and NR-02 firm power rate schedules. Subject to the availability of surplus firm power, sales of EPP under the FPS-96 rate schedule may be offered in the future. Esvelt *et al.*, WP-02-E-BPA-33, at 13.

The GEP will be negotiated and range from zero to $40/MWh depending on the specific resource types selected by each customer. The customer's power bill will have a new line item showing the elected EPP energy amount in MWh times the GEP. *Id.*

When the GEP is based upon existing BPA resources, BPA will incur no additional costs but will accrue additional revenues. Where the output of non-BPA resources is acquired to meet GEP requests, the GEP customer will pay all associated incremental costs. To the extent incremental GEP revenue is received, it will benefit BPA's customers at large. BPA forecasts no sales of EPP and thus no revenue from the GEP. Esvelt *et al.*, WP-02-E-BPA-33, at 14.

Because no party raised the issue of offering the GEP on brief, this issue is withdrawn in accordance with the *Procedures Governing Bonneville Power Administration Rate Hearings*, §1010.3 51 Fed. Reg. 7611 (1986).

10.15 Targeted Adjustment Charge (TAC)

The TAC is a charge that is applied to the PF-02 firm power rate for customers that place unanticipated, incremental load on BPA during the FY 2002-2006 rate period. Arrington *et al.*, WP-02-E-BPA-24, at 1. The TAC recovers costs that BPA may incur, over and above the applicable rate, to serve incremental requirements loads. *Id*. The TAC will apply to customers that purchase firm power requirements service under the PF-02 rate after the Subscription window closes; to customers that add load through retail access after the window closes, including load that was once served and returns under retail access; and to customers applying for service to replace their own firm resources. *Id.* at 2. When applied to the PF-02 rate, the TAC is a mills/kWh adjustment to the HLH and LLH energy rates specified in the 2002 rate schedules. *Id.* at 3. The TAC will not apply to the PF Exchange Program rate, because the Residential Exchange Program determines exchange benefits for residential and small farm customers and does not actually deliver power. *Id.* at 2. The TAC also does not apply to the PF Exchange Subscription rate, because the Residential Exchange settlement is available only during the Subscription window. *Id.* The TAC also applies to the NR rate. Arrington *et al*., WP-02-BPA-49, at 5.

Issue 1

Whether the TAC is cost-based and results in a tiered PF rate that is discriminatory and unfounded in law.

Parties' Positions

PPC argues that BPA's policy decisions to serve nonpreference customers, which reduce the available FBS resources to serve preference agency loads, taken together with its proposed imposition of a TAC on certain preference agency loads, create tiered rates for preference agency customers. PPC Brief, WP-02-B-PP-01, at 25. PPC quotes and cites the following language from section 4(a) of the Bonneville Project Act: "the administrator shall at all times, in disposing of electric energy generated at said project, give preference and priority to public bodies and cooperatives," 16 U.S.C. §832c(a); section 4(d) of the Bonneville Project Act, "[I]t is declared to be the policy of the Congress, as expressed in this chapter, to preserve the said preferential status of the public bodies and cooperatives herein referred to . . . ," 16 U.S.C. §832c(d); and section 7(b)(1) of the Northwest Power Act,

> The Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the PNW, and loads of electric utilities under §839c(c) of this title. Such rate or rates shall recover the costs of that portion of the FBS resources needed to supply such loads until such sales exceed the FBS resources.

16 U.S.C. §839e(b)(1). *Id.* at 26.

PPC argues that taken together, the spirit of these statutes is to ensure that publicly and cooperatively owned preference customers are entitled to priority in the purchase of Federal power at cost. *Id.* at 26-27. PPC adds that these provisions, along with the protections afforded preference customers in section 7(b)(2) of the Northwest Power Act, provide those customers the right to purchase Federal power at BPA's lowest cost-based rate and that the TAC cannot be reconciled with BPA's statutory rate directives. PPC Ex. Brief, WP-02-R-PP-01, at 6.

OURCA argues that the TAC is inconsistent with the statutory mandate in section 7(b)(1) of the Northwest Power Act that rates must be cost-based for public preference customers. OURCA Brief, WP-02-B-OU-01, at 5.

ICNU argues that TAC limits access to firm power by charging preference customers when they place unanticipated, incremental loads on BPA during the FY 2002-2006 rate period. ICNU Brief, WP-02-B-IN-02, at 8. ICNU suggests that TAC is a pricing tool designed to limit the amount of preference power available to BPA's public agency customers in violation of section 4(b) of the Bonneville Power Act.

BPA's Position

The TAC could potentially be applied to all preference customers purchasing firm power under the PF rate schedule. Arrington *et al.*, WP-02-E-BPA-24, at 3. The TAC is a charge that is applied to the PF-02 firm power rate for the customers that place unanticipated, incremental load on BPA during the FY 2002-2006 rate period. *Id.* at 1. The TAC recovers the costs BPA may incur, over and above the applicable rate, to serve incremental requirements loads. *Id*. at 1-2. The TAC will be calculated for an individual customer, upon request by the customer for PF service after the Subscription window closes, or for certain other unanticipated incremental loads. *Id.* When applied to the PF-02 rate, the TAC is a mills/kWh adjustment to the HLH and LLH energy rates specified in the 2002 rate schedules. *Id.*

Evaluation of Positions

PPC contends that the TAC creates a tiered rate for Federal power service to preference agency loads. PPC Brief, WP-02-B-PP-01, at 24. PPC claims that BPA's decisions to serve nonpreference customers have had the effect of reducing the availability of the FBS resources to serve public agency loads. PPC further argues that despite that reduction, and BPA's legal obligation to supply preference customers with Federal power at cost, BPA's decision to apply the TAC is a continued refusal to implement the law. PPC Ex. Brief, WP-02-R-PP-01, at 6. As a result, PPC claims, market-based costs that preference agency loads would not otherwise bear will be imposed through TAC and through other related adjustments and charges for service from the FBS. PPC Brief, WP-02-B-PP-01, at 24. PPC maintains that the TAC is not in keeping with the spirit of applicable statutory preference provisions and section 7(b)(1) of the Northwest Power Act, 16 U.S.C. §839e(b)(1). *Id.* at 24. OURCA argues that the TAC is inconsistent with the statutory mandate in section 7(b)(1) of the Northwest Power Act that rates must be cost-based for public preference customers. OURCA Brief, WP-02-B-OU-01, at 5.

BPA does not dispute that public body and cooperative utility customers are entitled to preference and priority under BPA statutes. *See* 16 U.S.C. §832b and §832c(a). The statutory provisions cited by the PPC, OURCA, and ICNU, however, do not prohibit BPA from establishing the TAC as proposed. The TAC as proposed under section 7 of the Northwest Power Act is consistent with the preference and priority accorded to public body and cooperative utilities under the provisions of statute cited by these parties.

PPC's and OURCA's argument that the TAC is not cost-based appears to reflect the position that any power that BPA purchases from the market to serve preference agency customer load is not cost-based pursuant to section 7(b)(1) of the Northwest Power Act. 16 U.S.C. §839e(b)(1). Contrary to the parties' contention, however, the power purchased to meet the load that is subject to the TAC is FBS replacement power, Tr. 1101; the cost of which must be recovered consistent with section 7(b)(1) of the Northwest Power Act. Pursuant to section 3(10) of the Northwest Power Act, BPA may acquire resources to replace reductions in capability. Section 3(10) expressly provides that such replacement resources are FBS resources. For this reason, BPA's costs included in the TAC to replace reductions in the capability of the FBS resources are the costs of FBS resources. The TAC is a charge that is applied to the PF-02 rate for customers that place unanticipated, incremental load on BPA during the FY 2002-2006 rate period. Arrington *et al.,* WP-02-E-BPA-24, at 1. Under BPA's broad authority to design its rates to recover its total costs to meet its revenue requirement, an adjustment charge such as the TAC is appropriate. 16 U.S.C. §839e(e). "In short, the statute does not require BPA to impose any particular type of rate on its customers. Rather, it restricts BPA only to 'sound business principles' in setting rates to meet its revenue requirements." *City of Seattle v. Johnson*, 813 F.2d 1364 (9th Cir. 1987). PPC also claims that TAC cannot be reconciled with the preference provisions in BPA's statutes and cites to section 7(b)(2) of the Northwest Power Act. PPC Ex. Brief, WP-02-R-PP-01, at 6. Contrary to PPC's claim, BPA is establishing its priority firm power rate as directed by section 7(b)(2). BPA's preference customers purchasing under the PF-02 rate are being afforded the appropriate rate protection as required under section 7(b)(2). *See* Wholesale Power Rate Development Study, WP-02-E-BPA-05A, at 72 (*see e.g.,* RDS 30 and RDS 31). When applied to the PF-02 rate, the TAC is a mills/kWh adjustment to the HLH and LLH energy rates specified in the 2002 rate schedules. Arrington *et al.*, WP-02-E-BPA-24, at 2.

Section 7(e) of the Northwest Power Act grants the Administrator considerable rate design discretion, including the ability to employ rate designs that use a value-of-service approach or market-based approach, or rate designs which recover BPA's costs through formula rates or pricing methodologies. Section 7(e) provides that:

> Nothing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal, or other rate forms.

16 U.S.C. §839e(e).

BPA's rates are certainly "cost-based" in the sense that BPA's rates "have regard to" cost recovery and, in the aggregate, do ultimately result in total cost recovery. Nevertheless, within the context of those directives, section 7(e) and its legislative history make clear that the cost allocation directives concern the amount of revenues to be recovered from customer classes, and not the design of the rates to recover those revenues. Congress did not direct BPA to use specific rate structures or billing practices to show the cost of new power supplies. As a result, it was recognized that many provisions could lead to rate reforms. *See, e.g., Comptroller General of the United States, Comments on Pacific Northwest Power Planning and Conservation Act—* H.R. 8157, reprinted in Cong. Rec. H 10687 (November 17, 1980).

Based on this broad authority, it is prudent for BPA to establish an adjustment charge to the base PF-02 rate that recovers the cost of serving unanticipated, incremental load during the rate period. Targeting the customer load that is causing the costs to be incurred is appropriate under the TAC, because it will apply to "those preference customers that place load that BPA did not anticipate serving to pay a price for firm power which reflects the cost to BPA of purchasing to serve this unanticipated load." Arrington *et al*., WP-02-E-BPA-24, at 3. As BPA testified, the TAC is based on the additional cost to BPA. Tr. 1075.

BPA does not agree with the PPC's contention that the TAC creates a tiered rate. The TAC will apply for the duration of the customer's contract or until 2006, whichever occurs first. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 37. As such, the TAC is an adjustment charge that applies no longer than the PF-02 rate period. The TAC will be calculated for an individual customer upon request by the customer for PF service after the Subscription window closes, and for certain other unanticipated incremental loads. Arrington *et al.*, WP-02-E-BPA-24, at 2. BPA may not be asked to serve any load under this charge. In fact, BPA does not expect to serve incremental loads and is forecasting that zero loads will be served under this charge. *Id.* at 6.

OURCA argues that the TAC is inconsistent with the Northwest Power Act because, OURCA claims, the Northwest Power Act requires BPA to reserve sufficient FBS resources to serve additional requests for service by public preference customers during the rate period. OURCA Brief, WP-02-B-OU-01, at 5; OURCA Ex. Brief, WP-02-R-OU-01, at 5. OURCA argues that, contrary to the statutory mandates of the Northwest Power Act, BPA's TAC proposal allows the nonpublic preference customers to reap benefits not accorded the public preference customers. *Id.* OURCA argues that the preference rights are mandatory, not discretionary, *Id.*, and cites section 5(a) and section 5(b)(2) of the Northwest Power Act and *City of Santa Clara, California v. Andrus*, 572 F.2d 660, 671 (9th Cir. 1978) to support its position. ICNU argues that the TAC limits access to firm power by charging preference customers when they place unanticipated, incremental loads on BPA during the FY 2002-2006 rate period. ICNU Brief, WP-02-B-IN-02, at 8.

As stated, BPA does not dispute that public body and cooperative utility customers are entitled to preference and priority under BPA statutes. OURCA's reliance on section 5(a) of the Northwest Power Act and the *City of Santa Clara* case are not dispositive on the issue of BPA's authority to sell power to non-preference customers, particularly once the net requirements of BPA's public body and cooperative utility customers have been met. The net requirements of BPA's preference customers will be met under contracts executed during the Subscription window. Burns and Elizalde, WP-02-E-BPA-37, at 4. BPA is not, however, obligated to hold a supply of available Federal power in reserve for the future needs of its preference customers. In fact, BPA is obligated to sell firm power to regional IOUs. Section 5(b)(1) obligates the Administrator to offer contracts to regional IOUs whenever requested. When BPA sells power to an IOU, section 5(b)(2) of the Northwest Power Act requires BPA to include in contracts with IOUs the right to reduce the Administrator's obligations under such contracts in accordance with section 5(a) of the Bonneville Project Act. Section 5(b)(2) states:

> Contracts with IOUs shall provide that the Administrator may reduce his obligations under such contracts in accordance with section 5(a) of the Bonneville Project Act of 1937 [16 U.S.C. §832d(a)].

16 U.S.C §839c(b)(2).

PPC argues that BPA's failure to exercise its legal authority to recall Federal power from other sales in order to meet the preference loads that may be assessed a TAC charge is discriminatory, arbitrary and capricious. PPC Ex. Brief, WP-02-R-PP-01, at 6. BPA's decision not to recall power sold to its nonpreference customers is not discriminatory, arbitrary, or capricious. To the contrary, BPA has reviewed it obligations under statute and determined that it is neither necessary, nor required at this time to recall power sold to BPA's nonpreference customers.

The notice language in section 5(a) of the Bonneville Project Act requires:

> [I]n the case of a contract with any purchaser engaged in the business of selling electric energy to the general public, the contract shall provide that the administrator may cancel such contract upon five years' notice in writing if in the judgment of the administrator any part of the electric energy purchased under such contract is likely to be needed to satisfy the requirements of said public bodies and cooperatives . . .

16 U.S.C. §832d(a).

This type of recall is to be used only when the Administrator has determined there would not be sufficient resources available on a planning basis to meet the Administrator's contractual load obligations to serve public agency customers. *Id.* Further, under section 5(d) of the Northwest Power Act, BPA is authorized to sell power under contracts with DSIs. Sales of power to nonpreference customers provide the preference customers a benefit through the additional revenues BPA receives through such sales. Such sales help keep BPA's rates low. If unanticipated, incremental load is placed on BPA by a preference customer during the rate period, the TAC will recover any costs BPA incurs to serve such customer. BPA's obligation to meet the net requirements of its preference customers is not impaired by the imposition of the TAC.

ICNU claims that preference customer access to firm power will be limited through application of the TAC during the 2002-2006 rate period. ICNU Brief, WP-02-B-IN-02, at 8. ICNU cites several sections of statute: section 4(b) of the Bonneville Project Act, 16 U.S.C. §832c(b) ("Preference rights apply whenever there 'are conflicting and competing applications for an allocation of electric energy' between a preference customer and a private agency."); *Aluminum Co. of America v. Cent. Lincoln Peoples' Utility District*, 467 U.S. 380, 393 (1984); and sections 5(a) and 7 of the Northwest Power Act, 16.U.S.C. §839c(a) and §839e. *Id.* ICNU's argument that preference customer access for firm power will be limited lacks analysis and is not persuasive. To the contrary, BPA's direct testimony is that the net requirements of BPA's preference customers will be met under contracts executed during the Subscription window. Burns and Elizalde, WP-02-E-BPA-37, at 4. The TAC does not preclude preference customers from requesting BPA to serve their unanticipated, incremental load with firm power. When requested by such customers, BPA will provide service. Arrington *et al.*, WP-02-E-BPA-24, at 2. Moreover, it is not certain that TAC will "make the price of BPA power . . . so unattractive that no reasonable customer would purchase BPA power and be subject to these charges" as claimed by ICNU. ICNU Brief, WP-02-B-IN-02, at 9. To the contrary, BPA testified that as applied, the TAC may be zero if the additional cost to serve is zero. Tr. 1075.

PPC argues that policy decisions, such as BPA's policy on determining net requirements, will directly impact service to preference agency customers at BPA's PF rate, as opposed to service at a market-based PF TAC rate. PPC Brief, WP-02-B-PP-01, at 27. PPC contends that BPA testified that loads previously served by a customer's own firm resource would be subject to the TAC irrespective of whether or not load is expected and committed to Federal service within the Subscription window. *Id.* PPC contends this is discriminatory treatment unfounded in the law. *Id.*

Although PPC asserts that BPA's policy decision on net requirements and the proposed TAC result in discriminatory treatment that is unfounded in the law, PPC fails to show or proffer any evidence on the record in support of its claim. PPC's assertion is weak and unsupportable and, therefore, not persuasive. Despite PPC's claim to the contrary, BPA has testified that it will not apply the TAC to certain requirements loads that are forecast to materialize during the upcoming rate period, subject to the determination in the policy on determining net requirements. Arrington *et al.*, WP-02-E-BPA-49, at 8. A public customer will be allowed to include net requirements load in the initial amount under the Subscription contract that is being served with resources the customer demonstrates to BPA will terminate during the period from October 1, 2001, through September 30, 2006. *Id.* The customer's load that was served by the terminated resource(s) will not be subject to the TAC if such demonstration can be made at the time the contract is executed, consistent with the policy on determining net requirements. *Id.* Load that does not meet this requirement will be subject to the TAC. *Id.*

<u>Decision</u>

The TAC is a cost-based adjustment to the applicable rate. The TAC is not a tiered rate and does not result in discriminatory rates.

<u>Issue 2</u>

Whether BPA's Loads and Resources Study, WP-02-E-BPA-01, presents a reasonable forecast of BPA's loads and resources to support BPA's determination to implement the TAC.

<u>Parties' Positions</u>

In its initial brief, PPC makes several new arguments regarding BPA's Loads and Resources Study, WP-02-E-BPA-01, which is used in support of BPA's determination to impose a TAC. PPC Brief, WP-02-B-PP-01, at 28-29. PPC argues that: BPA's load/resource balance analysis does not accurately predict if the agency will in fact be surplus or deficit for the FY 2002-2006 rate period; BPA's pending policy on determining net requirements will have an unknown impact on BPA's load/resource balance analysis; the outcome of the IOU settlement as a section 5(b) requirements sale or a sale under section 5(c) of the Northwest Power Act will have an impact on BPA's load/resource balance analysis; and there is an internal inconsistency showing the unreliability of the loads and resources estimates that support BPA's proposed TAC. *Id*.

BPA's Position

The only evidence on the record regarding the methodology used in developing the public agency load forecast is contained in BPA's direct case. Loads and Resources Study, WP-02-E-BPA-01, at 3-4; Loads and Resources Study Documentation, WP-02-E-BPA-01A, at 8-11. No party filed any direct or rebuttal testimony demonstrating that a customer-specific methodology was preferable or that an aggregate approach was unacceptable. No party cross-examined BPA witnesses on loads and resources on this topic either, leaving BPA's Loads and Resource Study, WP-02-E-BPA-01 and Loads and Resources Study Documentation, WP-02-E-BPA-01A, unrebutted. Nor did any party present any direct or rebuttal testimony demonstrating that BPA's net requirements policy, including the outcome of the IOU exchange settlement, would have any impact on BPA's loads and resources forecast.

Evaluation of Positions

PPC argues that BPA's load/resource balance analysis does not accurately predict if the agency will in fact be surplus or deficit for the FY 2002-2006 rate period, because it is not performed on a customer-specific basis. PPC Brief, WP-02-B-PP-01, at 28. PPC also refers to "questionable assumptions" about continuing "diversification" levels and public agency annexations. *Id*. This statement suggests that the PPC doubts the reasonableness of the forecasts of these items.

The PPC has not offered any evidentiary support for the conclusion that the aggregate method used to forecast public agency loads presented in BPA's direct case is unreasonable. Nor has the PPC offered any evidentiary support for the conclusion that the assumptions about the level of diversification and the anticipated annexation of new public loads in BPA's direct case are unreasonable. Rather than pointing to some evidence in the record, the PPC relies on conclusory statements in its brief that the method and assumptions employed in BPA's direct case will result in inaccurate predictions. PPC Brief, WP-02-B-PP-01, at 28. Without some factual support in the record to support rejecting the methodology and assumptions contained in BPA's direct case, it would be unreasonable to do so.

PPC had ample opportunity to offer alternative methods and assumptions for these items in its direct case or to question the reasonableness of these items during cross-examination. Neither they, nor any other party, did so. Therefore, it is inappropriate to question the validity of these items at this juncture. PPC argues that because BPA's net requirements policy has not yet been published, its impact on BPA's load/resource balance analysis cannot be known at this time. PPC Brief, WP-02-B-PP-01, at 28. The PPC has not offered any evidentiary support for the inference it makes that BPA's net requirements policy will have an impact on BPA's forecast of public agency loads. BPA testified that it believes there will not be a substantial change to its load forecast resulting from BPA's final policy on net requirements. Tr. 1085. Without some factual support in the record, it would be unreasonable to reject the forecast contained in BPA's direct case.

PPC argues that BPA's load/resource balance is further weakened by not accounting for the IOU settlement as a Northwest Power Act section 5(b) requirements sale. PPC Brief, WP-02-B-PP-01, at 28. PPC contends that if the outcome of the settlement is based on a section 5(c) sale under the Northwest Power Act, it will reduce the agency's need for system augmentation. *Id*. at 29.

The PPC has not offered any evidentiary support for its claim that the IOU settlement will weaken BPA's Loads and Resources Study, WP-02-E-BPA-01. Rather than pointing to some evidence in the record, the PPC relies on a conclusory statement in its brief that the outcome of the IOU settlement will weaken BPA's Loads and Resources Study, WP-02-E-BPA-01. *Id*. Without some factual support in the record to support rejecting the assumptions contained in BPA's direct case, it would be unreasonable to do so. In addition, sales made under sections 5(c) and 5(b) are in fact direct sales. Regardless of whether BPA's IOU settlement sales are made under section 5(b) of the Northwest Power Act using the RL rate or section 5(c) using the PF Exchange Subscription rate, there will be an actual power sale to the purchasing utility. That is what the Subscription Strategy settlement intends for IOU settlement sales. Because the sale is an actual delivery of power, the forecast is correct for sales under either section 5(b) or 5(c).

PPC argues that from BPA's load/resource analysis it can be concluded that the region is 189 aMW deficit at the end of Operating Year (OY) 2006. PPC Brief, WP-02-B-PP-01, at 29. PPC states that while this conclusion seems to support BPA's testimony that it will have to supplement the FBS to serve some post-2001 public agency load, elsewhere BPA testifies that there is no constraint on the supply of Federal power available for preference customers for the FY 2002-2006 rate period. *Id*. PPC then asks the question: "In a period of deficit with no planned recall, how is it that 'no constraint' exists when preference customers face the market price, rather than PF?" *Id*.

Again, PPC makes conclusory statements without any evidence to support its conclusions. PPC has misinterpreted the Loads and Resources Study, WP-02-E-BPA-01, and wrongly concludes that BPA will be deficit. After properly accounting for sales forecasts and BPA's contractual obligations in this rate case, and Federal system resource estimates including capacity for energy exchanges, contractual resources, and other BPA hydro-related contracts, BPA is in load/resource balance on a fiscal year basis. Arrington *et al*., WP-02-E-BPA-24, at 6; Loads and Resources Study, WP-02-E-BPA-01, at 2. *See* table, *Id*. at 18. The TAC will provide BPA the flexibility to meet increases in BPA's regional firm load obligations during the rate period, Arrington *et al*., WP-02-E-BPA-49, at 2; and to recover the costs of incremental, unanticipated load that is not forecast to be served during the FY 2002-2006 rate period, Arrington *et al*., WP-02-E-BPA-24, at 2. BPA does not expect to serve incremental loads and is forecasting that zero loads will be served under this schedule. *Id*. at 6.

<u>Decision</u>

BPA's Loads and Resources Study, WP-02-E-BPA-01, presents a reasonable forecast of BPA's loads and resources and supports BPA's determination to implement the TAC.

<u>Issue 3</u>

Whether BPA's decision regarding exercising its right to recall power to serve requirements load violates the Northwest Power Act.

Parties' Positions

NRU argues that as a matter of law, if firm power is available, or if BPA could make it available by exercising rights to recall power, public agency customers are entitled to receive it based on their statutory rights as preference customers, and they should pay only a cost-based PF-02 rate. NRU Brief, WP-02-B-NI-02, at 28. PPC notes that BPA does not plan to exercise its legal authority to recall Federal power from other sales in order to meet the preference loads that will otherwise be assessed a TAC. PPC Brief, WP-02-B-PP-01, at 25.

BPA's Position

While BPA does have a statutory obligation to include in contracts a right to recall surplus firm power sold or exchanged under extraregional contract, as well as surplus firm power sold as replacement power in the region, BPA has determined that it is not necessary at this time to exercise that right. Arrington *et al*., WP-02-E-BPA-49, at 7. On a planning basis, BPA has determined that it can meet all expected PNW customer requirements without having to exercise its rights to recall surplus firm power by purchasing in the market or relying on seasonal surplus firm power. *Id*.

Evaluation of Positions

NRU argues that BPA is obligated by law to use its statutory and contractual recall rights to make FBS power available to serve public agency customers. NRU Brief, WP-02-B-NI-02, at 28. PPC notes that BPA does not plan to exercise its legal authority to recall Federal power from other sales in order to meet the preference loads that will otherwise be assessed a TAC. PPC Brief, WP-02-B-PP-01, at 25. PPC states that BPA will not recall despite a "number of contracts identified in this rate case that could be recalled for the purpose of serving regional load totaling approximately 200 aMW." *Id*.

While BPA does have a statutory obligation to include a right to recall surplus firm power sold or exchanged under extraregional contract, as well as surplus firm power sold as replacement power in the region, BPA has determined that it is not necessary at this time to exercise that right. Arrington *et al*., WP-02-E-BPA-49, at 7. BPA's obligation regarding recall of surplus firm power under extraregional power sales contracts arises under section 3(a) of the Pacific Northwest Consumer Power Preference Act of 1964, 16 U.S.C. §837b(a). Section 3(a) provides in part:

> Any contract for the sale or exchange of surplus firm energy for use outside the PNW, or as replacement, directly or indirectly, within the PNW for hydroelectric energy delivered for use outside the region by a non-Federal utility, shall provide that the Secretary, after giving the purchase notice not in excess of 60 days, will not deliver electric energy under such contract whenever it can reasonably be foreseen that such delivery would impair his ability to meet, either at or after the time of such delivery, the energy requirements of any PNW customer.

16 U.S.C. §837b(a).

Consistent with the law, BPA does not foresee that its ability to serve returning uncommitted load of customers subject to the TAC is impaired because of sales of surplus firm power under extraregional contracts. The 1974 Transmission Act and the 1980 Northwest Power Act grant BPA ample authority to acquire power to meet the Administrator's obligations under contract to serve load. As long as resources can be acquired and are available on a planning basis to meet BPA's load requirements, BPA can reasonably foresee that its ability to serve unanticipated load will continue unimpaired. Further, the exercise of the Administrator's right to recall surplus firm power under extraregional contracts is compelled to meet the Administrator's supply obligation only. Recall is not required to provide any customers a price. On a planning basis, BPA has determined that it can meet all expected PNW customer requirements without having to exercise its rights to recall surplus firm power by purchasing in the market or relying on seasonal surplus firm power. Arrington *et al*., WP-02-E-BPA-49, at 7.

Decision

BPA's decision not to recall power to serve requirements load is consistent with the directives of the Northwest Power Act.

10.16 Cost-Based Indexed Rate Options

10.16.1 Cost-Based Indexed PF Rate

The cost-based indexed PF rate is a rate conversion from the applicable PF rate to a market-indexed or floating price. Miller *et al.*, WP-02-E-BPA-21, at 16. The rate indexed to market would not be fixed but would rise and fall with market prices, although it is adjusted for BPA's risk and designed to achieve revenues equivalent to the applicable PF rate. *Id.* at 17. There are several reasons why BPA is offering the cost-based indexed PF rate. *Id.* First, it extends BPA's ability to offer its customers pricing flexibility related to the market. *Id.* Second, the cost-based indexed PF rate allows BPA to better tailor the rate to reflect the risks associated with the market. *Id.* Third, it is an alternative to take-or-pay contract provisions, since the customer assumes the market risks. *Id.* Finally, it provides a product alternative to BPA's customer's end-use consumers, particularly industrial and large commercial loads, seeking market-based electric rates. *Id.* During contract negotiations the customer may request the cost-based indexed PF rate; it is, however, in BPA's discretion to offer this product. *Id.* If BPA decides to offer the product, BPA and the customer will negotiate and agree on either a commercially viable cash index or a futures index with which to reference the rate price. *Id.* For example, the COB DJ cash indexes or the New York Mercantile Exchange (NYMEX) futures contract at COB, or some other commercially recognized combination may be used to arrive at an agreed-upon index. *Id.* If a cash index is chosen, BPA will use that index to establish the monthly settlement price for the customer's power bill. *Id.* If a futures index is chosen, BPA will set the index price based on a monthly settlement formula taken from that index. *Id.* Whichever kind of index is used, the monthly price for power will be set based upon a negotiated formula for calculating price. *Id.* Such a formula may be either a single expiration price, a monthly average, or some other average of the month's prices. *Id.*

Because BPA will base the index pricing on a current market forecast of the market index referenced, BPA will adjust the current market price over the contract period against BPA's cost.

Id. at 18. This may result in either a discount or a premium that will be applied to the calculation of each month's bill. *Id.* In addition, BPA will add a hedging or insurance cost. *Id.* Such insurance, in the event market prices are below BPA costs, may consist only of the premium or difference between cost and market. *Id.* If, on the other hand, market prices are above BPA costs, such insurance may reduce the amount of any monthly discount applied to a customer's power bill. *Id.* The expected NPV revenue of the forecast index prices will be adjusted by a HLH and LLH Market Index Monthly Adjustment (MIMA) to equal the expected NPV of the applicable PF rate. *Id.* The MIMA is the difference between cost and market for power in both HLH and LLH periods indexed and adjusted monthly. *Id.* In the case of a discount to market, MIMA includes the added cost of price insurance. *Id.* The MIMA is calculated at the time of contract origination and remains effective throughout the life of the contract. *Id.* The MIMA essentially allows BPA to mark an index contract up or down from market prices, and back to BPA's cost, based on the current forward market transaction price. *Id.* By doing this the forecasted revenues will be equal to revenues under the posted PF rates. *Id.*

Customers can elect to apply this rate up to five years. *Id.* Customers who elect a contract length of less than five years and wish to renew may be subject to rates established under a new rate case and the recalculation of the MIMA. *Id.*

Unlike prices under fixed rate schedules, the price for power sold under contracts subject to the cost-based indexed PF rate will change with the market. *Id.* at 19. Because of market volatility, market prices range widely. *Id.* Therefore, the risk inherent in the cost-based PF rate could be great. *Id.* For BPA, the risk is that market prices will fall, resulting in a below-cost price. *Id.* For customers, the risk is that prices will rise, resulting in a higher price than they would have paid at a fixed PF rate. *Id.*

To protect itself from underrecovering system costs, BPA will use risk management tools, such as put options, to protect such contracts. *Id.* The cost of such insurance will be a reduction to any discount when market prices are above the PF rate at the time a contract is signed. *Id.* If market prices are below the PF rate, then BPA will add an appropriate premium to the monthly calculation of the settlement price (*see* above discussion of MIMA). *Id.* The settlement price is based on a mutually agreed-to formula that calculates an average based on some certain number of days within the delivery month; *e.g.*, average of last 15 days in the delivery month. BPA may also use index-type transactions of this kind to protect itself against higher-than-PF market purchases. *Id.*

PPC opposed BPA's proposal to price requirements service at the Cost-Based Indexed PF rate, arguing that it is a fiction the rate is cost-based and that by offering this rate design, additional risks and costs will be borne by BPA's other customers. Opatrny *et al.*, WP-02-E-PP-02, at 25. In BPA's rebuttal testimony, BPA stated that the Cost-Based Indexed PF rate is being proposed in this rate case to provide customers with flexibility to choose a floating price under BPA's fixed cost-based rate. Miller *et al.*, WP-02-E-BPA-46, at 25. The cost-based indexed PF rate is indexed to market and hence, will rise and fall with market prices. *Id.* The Cost-Based Indexed PF rate will be adjusted for BPA's risk and is designed to achieve revenues equivalent to the applicable PF rate. *Id.* The Cost-Based Index is priced at the time of contract origination and will account for any difference between BPA and market prices when market prices are above the fixed PF rate. BPA is confident that such sales, as they are currently and prospectively structured, are cost-based and will not result in the additional risks alluded to in PPC's testimony. *Id.* Neither PPC, nor any other party raised the issue of the cost-based indexed PF rate on brief. *See Procedures*, 51 Fed. Reg. 7611 (1986).

10.16.2 Cost-Based Indexed IP Rate

Issue 1

Whether BPA should offer the DSI customers a Cost-Based Indexed IP rate option.

Parties' Position

WPAG argues that BPA should not offer the Cost-Based Indexed IP rate option (indexed rate) to the DSIs. WPAG Brief, WP-02-B-WA-01, at 12. WPAG argues that prior indexed, or variable, IP rates were offered when there were benefits to BPA in offering such a rate, including the need to retain DSI load, but that those benefits are not present today. *Id*. WPAG argues that BPA has presented no evidence to support the contention that some DSI aluminum smelters may not survive absent an indexed rate. And even if such evidence were in the record, offering a discount rate to a subset of BPA's customers on the premise that their financial survival is in question may be inconsistent with BPA's obligation to set rates in a sound and business-like manner. *Id*. WPAG concludes that the indexed rate is designed to attract substantial amounts of load of customers that may not survive through the rate period, and that while BPA may have the discretion to offer an indexed rate, there is no compelling reason to do so. *Id*. at 13.

In a related argument, SUB argues that BPA's proposal to enter into 100 percent firm power sale agreements with the DSIs in the post-2001 period violates the preference and priority rights of public customers. SUB Brief, WP-02-B-SP-01, at 2-3. SUB argues such sales also are inconsistent with the precedent set by contracts entered into by BPA with the DSIs prior to the Northwest Power Act (16 U.S.C. §839-839h), which provided that a portion of such sales were subject to interruption, thus making that portion subject to the preference provisions of the Bonneville Project Act (16 U.S.C. §832-832m) and enabling preference utilities to interrupt it whenever they wanted nonfirm energy. *Id*. at 3. SUB appears to conclude that because the pre-Northwest Power Act contracts with the DSIs were discretionary and contained interruption rights, that discretionary post-2001 DSI contracts must also contain interruption rights to comply with the preference and priority provisions of the statutes. *Id*. Alternatively, SUB proposes that these defects may be cured by adopting SUB's proposals for correcting BPA's 7(c)(2) rate proposal. *Id*. at 4.

No other party opposes BPA's proposal to offer an indexed rate to the DSIs. However, other parties do argue for different treatments of the proposed parameters of the indexed rate, the level of risk associated with the rate, and how that risk should be mitigated by BPA. These issues are addressed at Issue 2 in this section.

BPA's Position

BPA argued that a conservatively structured indexed rate that does not place unreasonable levels of additional cost risk on other customers will provide an important short-term survival tool for DSI aluminum smelters. Miller *et al*., WP-02-E-BPA-21, at 2. Some DSIs represented to BPA that the availability of an indexed rate in the event of low aluminum prices will likely be important to their decision to maintain the operation of some of the aluminum smelters. *Id*. The 10 aluminum smelters and 1 aluminum rolling mill in the region served directly by BPA directly employ approximately 10,000 workers at full operations. *Id*. at 3.

BPA conducted a general analysis of the aluminum industry in the region to determine the effect power prices would have on the continuation of smelter operations under different aluminum prices. Berwager *et al*., WP-02-E-BPA-09, at 11. BPA concluded from this analysis that under certain reasonably possible combinations of low aluminum and high power price assumptions, the proposed indexed rate would provide an important tool to improve the likelihood of smelter survival. *Id*. at 11-14. The indexed rate was designed around rate and aluminum price parameters so that, on a projected basis, BPA will recover revenues over the rate period equivalent to revenues it would recover from a DSI through the proposed fixed IPTAC rates. Miller *et al*., WP-02-E-BPA-21, at 3.

Evaluation of Positions

WPAG correctly points out that BPA does not benefit from an indexed rate for the DSIs in the upcoming rate period as it did under prior DSI indexed or variable rates. BPA's benefit from past variable rates was sales for BPA during periods of large power surpluses and low energy market prices in limited markets. Miller *et al*., WP-02-E-BPA-46, at 22. The general belief today is that energy market prices during the 2002-2006 period will be fairly robust, so those particular benefits will not likely occur. *Id*. However, BPA proposed the indexed rate primarily to help mitigate the possibility, during temporary periods of low aluminum prices, of aluminum smelter shutdown and the consequent loss of smelter jobs. *Id*. WPAG's assertion is incorrect that "[n]ot a shred of evidence," WPAG Brief, WP-02-B-WA-01, at 12, has been introduced into the record to support the contention that such a rate may enhance the prospect of smelter survivability.

BPA conducted a general survivability analysis using scenarios with power market rates during FY 2002-2006 that averaged 26, 28, and 30 mills/kWh and combined them with aluminum price scenarios of 60, 65, 70, 75, and 80 cents per pound. Berwager *et al*., WP-02-E-BPA-09, at 11. Using four major elements of production cost data for each smelter (power, alumina, labor, and other) BPA analyzed likely smelter operations under these aluminum and power market conditions, assuming BPA would supply approximately half the smelter's power at 1 mill increments from 18 mills/kWh to 28 mills/kWh, with the other half supplied by the market at prices ranging from 26 to 30 mills/kWh. *Id*. Based on this analysis, BPA concluded that the likelihood that smelter operations would continue was most sensitive to energy prices when aluminum prices were in the 65 to 70 cents per pound range under all the power market price scenarios (26, 28, and 30 mills/kWh). *Id*. at 12. To take just one scenario examined, BPA's analysis suggests that if aluminum prices are at 68 cents and the smelters had to purchase all their power in the market at 28 mills/kWh (approximately BPA's estimate of the average long-term purchase price for five-year flat-block energy, *see* Oliver *et al*., WP-02-E-BPA-20, at 7); then 68 percent of smelter loads are at risk of not operating. *Id*. at 13. At this combination of aluminum and energy market prices, however, the amount of smelter load at risk drops by approximately one-half to two-thirds if BPA supplies half the smelter's power under the applicable indexed rate. *Id*.

WPAG suggests that, even if survivability of the DSI smelters were demonstrated, offering a discount rate to a subset of BPA's customers on the premise that their financial survival is in question may be inconsistent with BPA's obligation to set rates in a sound and business-like manner. WPAG Brief, WP-02-B-WA-01, at 12. WPAG states that the proposed IP indexed rate is a "rate concession" designed to attract a sizable amount of load with customers that BPA believes may not survive the rate period and that BPA believes are likely not to be able to pay their power bills in the future. *Id*. at 13.

WPAG's concerns are not supported by the record. The indexed rate was not designed to attract DSI load to that rate, and BPA would prefer that the DSIs make their purchases at the applicable fixed IPTAC rate. Miller *et al*., WP-02-E-BPA-46, at 11. Nevertheless, the effect of expected higher market prices for electricity is to make it more difficult for DSI operations to continue in the Northwest if the DSIs are required to purchase all or most of their power at those higher market prices during a period of low aluminum prices. Berwager *et al*., WP-02-E-BPA-09, at 6. The jobs in jeopardy are important to the region and, especially, to the communities in which these plants are located. *Id*. Service to these customers is consistent with BPA's mission to spread the benefits of Federal power widely throughout the region. *Id*.; *see also* Bonneville Project Act, 16 U.S.C. §832, §832e.

BPA recognizes there is a moderate risk that the power market could be below the proposed indexed rate lower rate limit of 19 mills/kWh at the time the DSI curtails load or shuts down its plant. Miller *et al*., WP-02-E-BPA-46, at 10, 13. However, any financial risk BPA faces from the inability of a DSI to survive through the next rate period is mitigated by the fact that any power returned to BPA for remarketing will more likely be sold into the market at an average price at or above the low indexed rate then being paid by such DSI, since smelter survivability is most imperiled at low aluminum prices and, therefore, a low indexed rate.

SUB argues that BPA's proposal to enter into 100 percent firm power sale agreements with the DSIs in the post-2001 period violates the preference and priority rights of public customers. SUB Brief, WP-02-B-SP-01, at 2-3. SUB cites *Aluminum Co. of America v. Central Lincoln Utility District*, 467 U.S. 380 (1984), (*Alcoa*) for the proposition that the preference and priority rights of BPA's preference customers are preserved with respect to administrative allocations of power to the DSIs after expiration of the DSIs' initial 20-year contracts. SUB Brief, WP-02-B-SP-01, at 3. BPA does not disagree that the preference and priority provisions apply to such discretionary sales to non-preference customers such as the DSIs, but BPA does not agree with SUB's conclusion that those rights are violated by BPA's proposal to enter into new five-year firm, non-interruptible contracts with the DSIs. SUB appears to argue that the discretionary or administrative post-2001 allocations of power to the DSIs require that those contracts mirror the interruptibility provisions of the discretionary pre-Northwest Power Act (the 1975) contracts in order to comply with the preference and priority provisions.

Under the 1975 contracts, the top quartile of power sold to the DSIs was subject to interruption "at any time," thereby making the top quartile of DSI power subject to the preference provisions of the Bonneville Project Act, 16 U.S.C. §832, §832d(a)), and enabling preference customers to interrupt it whenever they wanted nonfirm energy. *Alcoa*, 467 U.S. 380, 387 (1984). When BPA offered the DSIs their 1981 contracts, BPA interpreted section 5(d)(1)(b) of the Northwest Power Act to require only that the new DSI contracts were to "provide a portion of the Administrator's reserves for firm power loads within the region," 16 U.S.C. §839c(d)(1)(B)); so the new contracts allowed interruption only to protect BPA's firm loads and not to make sales of nonfirm energy. *Alcoa*, at 387. BPA's public preference customers challenged BPA's decision, but that decision was eventually upheld in *Alcoa*.

SUB's reliance on *Alcoa* for the proposition that the post-2001 contracts with the DSIs must be interruptible on the same terms as the 1975 contracts in order to comport with public preference is misplaced for several reasons. First, as pointed out by the court in *Alcoa*, under the 1975 contracts the difference between the top quartile and the other quartiles was the provision in those contracts that made the top quartile subject to interruption "at any time." That term allowed the Administrator to treat the top quartile as if it were uncommitted, and subjected it to preference. The other three quartiles were not subject to preference simply because the terms of the contracts did not so provide. The court concluded from this that "the distinction among the different quartiles under the 1975 contracts was a product of the terms of the contracts, not a requirement of the Project Act's preference provisions." *Alcoa*, at 394. Thus, *Alcoa* does not support SUB's contention that, in the case of a discretionary allocation of power to the DSIs, the preference laws required that only less than all-firm contracts may be offered to the DSIs.

Second, BPA does not dispute that the preference rules apply to post-2001 sales to the DSIs. *See Alcoa*, at 395, n. 10 (preference rules will apply to any subsequent contracts made with the DSIs). However, as discussed above, BPA is not obligated by the preference laws to offer less than all-firm contracts to the DSIs in order to provide preference customers with a source of nonfirm energy, and SUB has provided no evidence that there is any competing demand from any public preference customer to the proposed power allocation to the DSIs in order to meet its firm net requirements load, or that BPA is not meeting all such requests. *See* Loads and Resources Study Documentation, WP-02-E-BPA-01A. Finally, post-2001 section 5(d) sales to the DSIs, while discretionary, are still made pursuant to section 5(d)(1)(A) of the Northwest Power Act, which limits the reserves provided by the DSIs to those needed to meet the Administrator's firm power loads. 16 U.S.C. §839c(d)(1)(A). These reserves are not free, and the DSIs must be compensated for the right to interrupt power deliveries to provide these power reserves. However, as a result of deregulation and other factors, it may be neither necessary nor cost-effective for the PBL to purchase any reserves from the DSIs during the next rate period. *See* McRae *et al*., WP-02-E-BPA-29. However, the point is that section 5(d)(1)(A) requires that the DSIs' contracts be available for interruption to provide reserve power for only the firm, and not the nonfirm, loads of the Administrator.

Decision

BPA will offer an indexed rate option to its DSI aluminum smelter customers to further BPA's policy goal of enhancing DSI smelter survivability and associated smelter jobs during periods of low aluminum prices. In addition, BPA's proposal to make 100 percent of the firm power sales to the DSIs under either the applicable indexed or fixed IPTAC rates is consistent with the preference and priority provisions in BPA governing statutes.

Issue 2

Whether BPA's proposal correctly accounts for the risks associated with the indexed IP rate, including whether BPA should adopt a minimum aluminum price forecast of 74 cents.

Parties' Positions

The DSIs contend that BPA's indexed rate proposal does not adequately reflect the strong consensus of predictive aluminum price forecasts that aluminum prices will average 76 cents/lb. or higher during the 2002-2006 rate period, and is therefore not consistent with the Compromise Approach agreement. DSI Brief, WP-02-B-DS-01, 40-46. The DSIs argue that the indexed rate parameters negotiated between BPA and the DSIs, taken together with the "commonly accepted" meaning of the term "forecast," make it unreasonable to think that the DSIs ever agreed to BPA's proposal for a fully hedged indexed rate as part of the Compromise Approach agreement. *Id*. at 43. The DSIs propose that in setting the midpoint of the indexed rate, BPA should adopt an aluminum price forecast that gives at least equal weight to the actual forecasts in the record as it gives to forward price curves, and that the 74 cents/lb. proposal made by the DSIs' expert is the lowest reasonable midpoint. *Id*. at 43-44. They claim that an indexed rate with a midpoint of 74 cents/lb. will provide BPA median revenues that correspond to a fixed price of $23.50/MWh. *Id*. at 44. The DSIs argue that BPA's rationale in the Draft ROD, that an aluminum price forecast above 74 cents/lb. is not needed to address DSI survivability concerns, is not relevant to the Compromise Approach. DSI Ex. Brief, WP-02-R-DS-01, at 6. They contend that the indexed rate parameters must be based on an aluminum price forecast developed in the rate case, not on an assessment of smelter operations or smelter survivability developed in the rate case. *Id*. at 7. The DSIs also take exception to BPA's position that the DSI aluminum expert does not qualify as an independent consultant under the Compromise Approach agreement. *Id*. at 8.

The DSIs argue that the aluminum market "backwardization" extant at the time the Draft ROD was published will result in BPA fixing the midpoint of the indexed rate at a level much below expected real aluminum prices, with the consequence that the DSIs will not realize any advantage from the indexed rate, and making the financial hedge particularly costly. *Id*. at 44-45. The DSIs state that BPA does not intend to financially hedge all its other risks, and that it is particularly unfair to single out the DSIs to pay for what amounts to a very high cost hedge. *Id*. at 46. They urge BPA, if it adopts the proposal to fully hedge the indexed rate risk, to remain flexible as to both the spread and the timing of a DSI's commitment to an indexed rate, and that BPA should not place an absolute upper limit of 74 cents/lb. on the aluminum price midpoint. *Id*.

The IOUs argue that BPA's proposed design for the indexed IP rate places on other customer classes an unreasonable risk of cost shifts. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 63-64. The IOUs argue that BPA has not accounted for this risk, that BPA is proposing to absorb the risk associated with the varying price of aluminum, and that ultimately BPA may be forced to try to turn to its transmission customers to cover the costs of that risk. *Id*. at 64.

PPC argues that the proposed indexed IP rate, unless fully hedged by BPA and priced to include the full cost of the hedge, represents a significant cost to BPA's public utility customers. PPC Brief, WP-02-B-PP-01, at 60-61. PPC asserts that an unhedged indexed IP rate would be costly to other BPA customers, because their power costs would be less predictable, given the increased risk that BPA may need to resort to the proposed CRAC to cover any revenue underrecoveries associated with low aluminum prices, and because under the proposed CRAC such a rate increase is not offset by an equivalent rate decrease in the event of a revenue windfall associated with high aluminum prices. *Id*.

PPC proposes that all the indexed rate parameters should be adjusted at the time the hedge is made, to be consistent with the fully hedged position, and that the hedged position must reflect the "price of the options" embedded in the rate structure. *Id*. PPC asserts there is no justification for BPA's offer of a 2 cent "subsidy" and that this is inconsistent with the principle of offering a fully hedged rate with revenues equivalent to the applicable fixed IPTAC rate. *Id*. Finally, PPC maintains that basing the midpoint of the indexed rate on predictive price forecasts would expose BPA customers to significant risk and would fail to take into account the cost of the hedge, which should be paid by the DSIs. *Id*.

BPA's Position

BPA agreed in the Compromise Approach agreement to propose an indexed IP rate tied to the price of aluminum, in response to the assertion by some DSIs that the availability of such a rate will likely be important to their decisions to maintain the operation of some of the smelters in the event aluminum prices do not recover during the next rate period. Berwager *et al*., WP-02-E-BPA-09, 2-4; Miller *et al*., WP-02-E-BPA-21, at 2. However, BPA has consistently made it clear that a fundamental benchmark for any indexed rate was that it neither result in increases in BPA's proposed rates for other customers, nor place unreasonable levels of additional cost risk on other customers. *See e.g.*, Miller *et al*., WP-02-E-BPA-21, at 2-3; Miller *et al*., WP-02-E-BPA-46, at 3-4, 11, 22. Because the indexed rate moves up or down with the price of aluminum, such a rate clearly presents some revenue uncertainties for BPA due to potentially unstable or chronically depressed aluminum prices. *Id*. at 7. Because BPA has not accounted for this revenue risk in its planned net revenues for risk, it is necessary that if indexed rate contracts are signed BPA have the ability to simultaneously protect expected revenues by hedging against this risk with financial instruments. *Id*. Therefore, BPA proposed indexed rate parameters, including the lower and upper rate limits, the pivot points, and the slope, in an attempt to strike a balance between enhancing DSI smelter survivability during periods of low aluminum prices and creating a high probability of collecting revenues equivalent to the IPTAC rates of 23.5 mills/kWh and 25.0 mills/kWh over the five-year rate period, thereby mitigating risks to other customers. Miller *et al*., WP-02-E-BPA-21, at 9-11.

In addition, BPA proposed that the aluminum price forecast midpoint, which is the point at which the aluminum price and indexed power rate intersect at BPA's expected cost of service (23.5 or 25.0 mills/kWh), be set approximately 2 cents/lb. higher than the forward price for aluminum at the time indexed rate contracts are signed. Miller *et al*., WP-02-E-BPA-46, at 2-5. Again, this aspect of the proposal seeks to balance the DSIs' survivability concerns against the goal of not shifting unreasonable levels of cost risk to other customers. By proposing an aluminum forecast midpoint that is approximately 2 cents/lb. higher than transactable forward prices, BPA is assuming some aluminum price risk for the DSIs. *Id*. at 4. On the other hand, setting the midpoint no more than 2 cents/lb. above transactable forward prices will allow BPA to hedge this risk as soon as practicable to protect BPA's other customers from additional costs. *Id*.

The Compromise Approach agreement states that the price forecast used to establish the indexed rate will include both forward prices and aluminum price forecasts (Berwager *et al*., WP-02-E-BPA-09, Attachment 1), and BPA's proposal balances those two elements appropriately and fairly. Miller *et al*., WP-02-E-BPA-46, at 3. The more credence BPA places on the accuracy of long-term predictive price forecasts, the more risk BPA must assume. *Id*. The DSIs' proposal that BPA give more weight to the predictive forecasts would require BPA to accept aluminum price risk at levels higher than are required to meet BPA's fundamental goal for service to the DSIs, which is to enhance the prospects of smelter survivability during periods of low aluminum prices while not imposing additional costs on BPA's other customers. *Id*. BPA's proposal balances these goals by proposing to establish the aluminum forecast midpoint approximately 2 cents/lb. above the forward price at the time an indexed rate contract is signed, but not below 66 cents/lb. or above 74 cents/lb., and is fully consistent with the Compromise Approach agreement. *Id*. at 6.

<u>Evaluation of Positions</u>

The DSIs state that the record indicates a strong consensus among the predictive aluminum price forecasts that aluminum prices will average 76 cents/lb. or higher during the FY 2002-2006 rate period. DSI Brief, WP-02-B-DS-01, at 42. While acknowledging that the Compromise Approach does include forward price curves as part of the basis for the aluminum price forecast, the DSIs argue the large spread between forward prices and even the lowest of the range of predictive price forecasts in the record show that BPA is "not truly" giving any weight to the forecasts. *Id*. at 43. The DSIs conclude from this that BPA's proposal to establish the aluminum price forecast (and thus the indexed rate midpoint) approximately 2 cents/lb. above forward prices, but not lower than 66 cents/lb. or higher than 74 cents/lb., is inconsistent with the Compromise Approach agreement and "the reasonable expectations that the DSIs gained from negotiating the Compromise Approach with BPA." *Id*. The DSIs propose that the 74 cents/lb. forecast presented by the DSI expert is the lowest reasonable midpoint aluminum price for the indexed rate. *Id*. at 44. The DSIs' argument that BPA's proposal on this issue is inconsistent with the Compromise Approach is wrong because: (1) it fails to acknowledge the context in which BPA agreed to propose an indexed rate for the DSIs; and (2) it incorrectly concludes that BPA is not giving sufficient weight to predictive aluminum price forecasts in its proposal for establishing the indexed rate midpoint.

The indexed rate piece of the Compromise Approach agreement was based on the principle that BPA was willing to take a moderate amount of risk in order to fashion a DSI service package that would help enhance the prospects of DSI smelter survivability and preserve smelter jobs. Miller *et al*., WP-02-E-BPA-46, at 2. The DSIs' assertion that BPA's proposal violates the Compromise Approach because it would not allow the establishment of an aluminum forecast above 74 cents/lb. fails to acknowledge these fundamental principles around which the Compromise Approach agreement was negotiated. The record contains no evidence for the proposition that DSI smelter survivability is threatened if aluminum prices rise above 74 cents/lb., or conversely that an indexed rate midpoint above 74 cents/lb. would enhance survivability. In fact, BPA's analysis showed that of all the aluminum price scenarios examined, the likelihood that smelter operations would continue was most sensitive to energy prices when aluminum prices were in the 65 to 70 cent/lb. range under power market price scenarios of 26, 28, and 30 mills/kWh. Berwager *et al*., WP-02-E-BPA-09, at 12.

Nevertheless, the DSIs continue to argue BPA's conclusion that an aluminum price forecast above 74 cents/lb. is not needed to address DSI survivability concerns is not relevant to the Compromise Approach. DSI Ex. Brief, WP-02-R-DS-01, at 6. They contend that the indexed rate parameters must be based on an aluminum price forecast developed in the rate case, not on an assessment of smelter operations or smelter survivability developed in the rate case. *Id*. at 7. However, as already noted, the purpose for the indexed rate, in fact the primary purpose behind BPA's entire proposal for service to the DSIs, is to enhance the prospect for the survival of the DSI aluminum smelters and associated jobs during periods of low aluminum and high power prices, through the next rate period. *See, generally,* Berwager *et al*., WP-02-E-BPA-09; Berwager *et al*., WP-02-E-BPA-38; Miller *et al*., WP-02-E-BPA-21; Miller *et al*., WP-02-E-BPA-46; Tr. 938. Of equal importance to BPA is that this be done in a way that does not increase the rates of other customers, or place unreasonable levels of additional cost risk on those customers. *Id*. This context is made abundantly clear in a letter from BPA to the DSIs at the beginning of the negotiations that eventually led to the Compromise Approach agreement. *See* Cross-Examination Exh., WP-02-E-AL-05. In this letter, BPA's senior vice-president for the Power Business Line wrote:

> You have recently made us aware of your strong concern about the effect of rising market prices for electricity on the continued viability of aluminum plants in the PNW, and the attendant possible loss of high-paying jobs . . . In that light, we are prepared to discuss options that will help maintain plant operations and jobs, but that will not increase electricity rates to other Northwest consumers, including those served by publicly owned utilities and the residential and small farm consumers served by Northwest IOUs.

Id. It is unreasonable for the DSIs to argue that these principles now have no bearing on the level at which the aluminum price forecast is established under the Compromise Approach. As explained further below, the record indicates that establishing an aluminum price forecast above 74 cents/lb. will not serve to enhance DSI smelter survivability, but would place unnecessary cost risk on BPA's other customers.

BPA's proposal calls for upper and lower aluminum pivot points 6 cents/lb. above and below the indexed rate midpoint. Miller *et al*., WP-02-E-BPA-21, at 9. The lower pivot point is the point at which a further increase in the market price for aluminum results in an increase in the electricity price, and the upper pivot point is the point at which a further decrease in the price of aluminum results in a decrease in the electricity price. *Id*. Therefore, a 74 cent/lb. midpoint would result in a 68 cent/lb. lower pivot point (and a 19 mills/kWh BPA rate) and an 80 cent/lb. upper pivot point (and a 28.5 mills/kWh BPA rate). Under this scenario, a DSI that signed the Compromise Approach would not pay the equivalent of the fixed IPTAC rate of 23.5 mills/kWh until aluminum prices reached 74 cents/lb. Even assuming the DSIs were purchasing the other half of their load at market rates of 28 mills/kWh (which is almost 3 mills/kWh higher than the DSIs argue a flat block of power will cost in the market during the 2002-2006 period, *see* DSI Brief, WP-02-B-DS-01, at 33), and aluminum prices hover at 68 cents/lb. (19 mills/kWh), BPA's analysis suggests smelter survivability would not be threatened. Berwager *et al*., WP-02-E-BPA-09, at 13; Miller *et al*., WP-02-E-BPA-46, at 8.

The forecast range BPA is proposing gives the DSIs significant protection from downside aluminum prices that would threaten their survivability. Miller *et al*., WP-02-E-BPA-46, at 10. Conversely, a forecast set with an eye on the forward price protects BPA's other customers from indexed rate risks that could otherwise not be financially mitigated. *Id*. An aluminum price forecast midpoint above 74 cents/lb. cannot be justified from the evidence in the record concerning DSI smelter survivability, even if the consensus of the predictive aluminum forecasts in the record suggests that aluminum prices will equal or exceed 76 cents/lb. in the 2002-2006 period. The indexed rate concept was never intended to be used as an indirect means to lower the fixed rate price points of 23.5 and 25 mills/kWh, nor as a means to guarantee additional benefits to the DSIs. *Id*. at 11. At the higher aluminum prices predicted by the DSIs, survivability is not an issue, and BPA will not design its indexed rate so that those higher aluminum prices are necessary for BPA to recover its costs. *Id*.

The DSIs assert that BPA's proposal is inconsistent with the Compromise Approach agreement, because it fails to give "meaningful weight" to the predictive aluminum forecasts in the record, and that BPA's witness acknowledged at cross-examination that the DSI expert's forecast was reasonable. DSI Brief, WP-02-B-DS-01, at 44. Again, however, the fundamental principles around which the Compromise Approach agreement was negotiated were to enhance smelter survivability while not imposing additional costs on BPA's other customers. Miller *et al*., WP-02-E-BPA-46, at 3-4. BPA's proposal is to establish an aluminum price forecast on which to base the indexed rate midpoint that is approximately 2 cents/lb. above the forward price for aluminum, up to a maximum of 74 cents/lb. *Id*. at 4-6. A midpoint set as high as 74 cents/lb. is reflective of the potentially higher prices expected in the DSIs' own forecast and gives "meaningful weight" to that forecast, but the record demonstrates that a midpoint set above 74 cents/lb. is neither necessary to address smelter survivability nor consistent with BPA's principle of not imposing unreasonable cost risks on other customers. BPA agrees with the PPC's conclusion that the possibility of forecast error would expose BPA's other customers to significant risk. PPC Brief, WP-02-B-PP-01, at 61.

The DSIs cite a portion of the cross-examination transcript to support the conclusion that BPA's witness agreed that the aluminum price forecast of Wharton Econometric Forecasting Associates

Group (WEFA) (76.96 cents/lb.) and of the DSIs' expert, Mr. Robin Adams (base forecast of 78.5 cents/lb.) were reasonable. DSI Brief, WP-02-B-DS-01, at 44. What the BPA witness testified was that he believed Mr. Adams' forecast was "as reasonable as any other aluminum price forecast that's out there," Tr. 1009; and that the WEFA forecast was "more reasonable" compared to another independent forecast. Tr. 1011. In spite of DSI counsel's statement that he was using the term "reasonable" in the same sense that it was used in the Compromise Approach agreement, Tr. 1009, the colloquy between the BPA witness and DSI counsel on the issue clearly indicates the witness's testimony was in the context of examining the reasonableness of these predictive aluminum price forecasts *as* predictive forecasts and comparing each to the other, not whether the witness believed that such forecasts were "reasonable" under the Compromise Approach agreement. Tr. 1009-11.

In fact, the Compromise Approach agreement defines the rate case aluminum price forecast as being comprised of both forward price curves and "aluminum price forecasts provided to BPA by independent consultants." *See* Berwager *et al*., WP-02-E-BPA-09, Attachment 1. The BPA witness was not testifying to the reasonableness of any of the predictive aluminum price forecasts in this context, nor could he have, since predictive forecasts make up only one part of the "aluminum price forecast" defined in the Compromise Approach. In any case, Mr. Adams, as the expert witness retained by the DSIs, is not an "independent consultant," so while his forecast is informative and lends additional credence to the observation that the consensus of predictive forecasters is that aluminum prices will rise in the 2002-2006 period, it is neither the type of "aluminum price forecast" specified under the Compromise Approach agreement, nor independent.

The DSIs take exception to BPA's conclusion that Mr. Adams does not constitute an "independent consultant" under the Compromise Approach. DSI Ex. Brief, WP-02-R-DSI-01, at 8. *Id*. They argue that the mere fact that Mr. Adams was compensated by the DSIs for his work does not mean his opinions with respect to the future price of aluminum are not independent, and that BPA's position on this issue suggests BPA had a closed mind and never intended to weigh the evidence presented by the DSIs regarding the aluminum price forecast. *Id*. The DSIs state that BPA should find that the forecasts prepared by WEFA, CRU, and Mr. Adams were all prepared by independent consultants within the meaning of the Compromise Approach. *Id*. Whether Mr. Adams qualifies as an "independent consultant" within the meaning of the Compromise Approach is not ultimately important since BPA, in fact, has proposed to establish a range for the aluminum price forecast up to Mr. Adams's own median adjusted forecast of 74 cents/lb., based in part on Mr. Adams testimony. Additionally, as noted elsewhere, BPA's willingness to adopt an aluminum price forecast up to 2 cents/lb. above forward price quotes is due, in part, to the consensus among the predictive aluminum forecasts in the record, including that of Mr. Adams, that aluminum prices will move higher through the rate period.

Lastly, the DSIs argue that the aluminum market "backwardization" existing at the time the Draft ROD was published will result in BPA fixing the midpoint of the indexed rate at a level much below expected real aluminum prices, with the consequence that the DSIs will not realize any advantage from the indexed rate, and making the financial hedge particularly costly. *Id*. at 44-45. In fact, the DSIs' testimony acknowledges that while a backwardization is more frequently associated with increasing prices, that prices in some cases (35 percent using the example in the testimony) will fall. Adams, WP-02-E-DS-01, at 12-13. It is the prospect for a fall in prices during the time BPA is financially hedging its aluminum exposure that is of greatest concern to BPA. Miller *et al*., WP-02-E-BPA-46, at 4, 17. Although BPA views this risk as moderate, it does represent a risk nonetheless. Tr. 960-61. To the extent the DSIs are correct and the backwardization of the market is followed by rising aluminum prices, then the survivability concern will be mitigated in any case.

Nevertheless, BPA is mindful of the complexities of hedging the risks associated with the indexed rate, including any market anomalies that may be created by a backwardized aluminum market, and intends to lay off that risk in a timely and systematic manner that will be dictated in part by aluminum market conditions at the time indexed rate contracts are executed. *Id*.; Miller *et al*., WP-02-E-BPA-46, at 7. In this respect BPA agrees with the DSIs that there should be some flexibility regarding the timing of establishing the aluminum price forecast after contracts are signed. BPA intends to offer each DSI flexibility regarding the timing of establishing an indexed rate, which should also be advantageous to BPA from a risk management perspective. *Id*.

The IOUs argue that BPA's proposed design for the indexed IP rate places an unreasonable risk of cost shifts on other customer classes. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 63-64. The IOUs argue that BPA has not accounted for this risk, that BPA is proposing to absorb the risk associated with the varying price of aluminum, and that ultimately BPA may be forced to try to turn to its transmission customers to cover the costs of that risk. *Id*. at 64. Similarly, PPC argues that the proposed indexed IP rate, unless fully hedged by BPA and priced to include the full cost of the hedge, represents a significant cost to BPA's public utility customers. PPC Brief, WP-02-B-PP-01, at 60-61.

BPA agrees with these parties that an unhedged indexed rate would expose BPA's other customers to unacceptable levels of risk, but BPA has made it very clear that it does not intend to carry through the rate period any of the aluminum price risk associated with an indexed rate tied to the price of aluminum. Miller *et al*., WP-02-E-BPA-46, at 3; Tr. 959-60. BPA's proposal is to establish an aluminum price forecast that is up to 2 cents/lb. above forward price quotes obtained at the time the DSI elects to purchase under an indexed rate, but BPA will not establish a forecast lower than 66 cents/lb. or higher than 74 cents/lb. Miller *et al*., WP-02-E-BPA-46, at 2-6. This basic construct allows BPA to strike a reasonable balance between smelter survivability concerns during times of low aluminum prices, and the concerns of other customers that they not be exposed to unreasonable cost risks associated with the indexed IP rate. BPA believes under these parameters that it can effectively lay off those risks. Tr. 962. PPC asserts there is no justification for the "two cent subsidy" and that it is inconsistent with the principle of offering a fully hedged rate with revenue equivalent to the fixed IP rate. PPC Brief, WP-02-B-PP-01, at 61. However, BPA believes that a spread of up to 2 cents/lb. is appropriately reflective of the general consensus that aluminum prices will improve through the rate period, but only to the extent necessary to meet the goal of enhancing smelter survivability, and at prices that will allow BPA to hedge this risk as soon as practicable to protect BPA's other customers from additional costs. Miller *et al*., WP-02-E-BPA-46, at 4. In addition, BPA plans to lay off all the risk associated with the indexed IP rate, Tr. 1046-47, including the 2 cent/lb. spread between the forward price and the indexed rate midpoint, in as timely a manner as possible. Tr. 993-94.

PPC also suggests that the floor rate, ceiling rate, and the slope must also be subject to adjustment, and that the cost of any options must be accounted for in the rate, in order to accurately reflect the cost of the hedge. PPC Brief, WP-02-B-PP-01, at 61. This is incorrect. The indexed rate parameters were designed to create a high probability of collecting revenues equivalent to the IPTAC rates of 23.5 and 25 mills/kWh over the five-year rate period. Miller *et al*., WP-02-E-BPA-21, at 9. A lower rate limit of 19 mills/kWh was selected to limit the risk that BPA would underrecover revenues during this period, but a lower limit higher than this would lose its value as a tool for the smelters to cope with periods of low aluminum prices. *Id.* An upper rate limit set five mills/kWh higher than the projected cost-of-service appropriately balances the upside revenue gain associated with rising aluminum prices and provides a reasonable assurance of recovering revenues equal to the IPTAC. *Id*. at 10. It is not necessary to adjust the lower and upper rate limits or the slope in order for BPA to fully or cost-effectively hedge its indexed rate risk. *Id*. Whether BPA will be required to execute any option contracts associated with any particular indexed IP will not be known until BPA seeks to actually hedge the rate. However, BPA anticipates that if it must take option positions in order to round out its hedge, that it will be able to do so at little or no net cost. Miller *et al.*, WP-02-E-BPA-46, at 8, 16. To the extent there is any net cost, this is part of the moderate time-risk element that BPA agreed to take on behalf of the DSIs. *Id.* at 4.

Decision

BPA's proposal for establishing an indexed IP rate for its aluminum smelter customers strikes an appropriate balance between the goal of enhancing smelter survivability and associated jobs during times of low aluminum prices, and the goal of not shifting additional risks associated with that proposal to other customers. To that end, BPA's aluminum price forecast for the midpoint of the indexed rate will be set up to 2 cents/lb. above forward prices, but not above 74 cents/lb.

Issue 3

Whether BPA is proposing to impermissibly set certain indexed IP rates outside the rate case.

Parties' Position

ICNU argues that BPA is proposing to establish indexed IP rates for its non-aluminum DSI customers outside the scope of this rate case. ICNU Brief, WP-02-B-IN-02, at 4. ICNU argues that the impermissibility of "deferral ratemaking" is most evident with regard to BPA's DSI customer Elf Atochem, and that BPA has committed to setting an indexed rate for this company outside the scope of the rate case. *Id*. ICNU argues that BPA is prohibited under section 7(i) of the Northwest Power Act from establishing rates without conducting a public process and following statutorily prescribed procedures. *Id*. at 5. ICNU argues that BPA is proposing to establish indexed rates for non-aluminum DSI customers absent a hearing and the establishment of a record concerning such rates in violation of established ratemaking procedures, thereby preventing any adequate opportunity for parties to comment on, refute, or rebut BPA's proposed rates. *Id*. ICNU recommends that the Administrator reject BPA's proposal regarding the non-aluminum DSI indexed rates, or in the alternative establish a section 7(i) process to allow public comment on such rates. *Id*. at 6.

No other party took a position on this issue.

<u>BPA's Position</u>

BPA is not proposing to establish any rates, including indexed rates for its non-aluminum DSI customers, outside the rate case. The rate that would apply to any non-aluminum DSI that is also offered the indexed rate option will be the applicable IPTAC rate, which is currently proposed to be 23.5 mills/kWh. Miller *et al*., WP-02-E-BPA-21, at 6. Under BPA's proposal, any indexed rate offered to a non-aluminum DSI must be structured to recover the same revenue values as the applicable IPTAC. *Id*. Under BPA's proposal, securing a reasonable assurance of a revenue stream equal to the applicable IPTAC rate would be achieved through a combination of the design of the indexed rate parameters, and if necessary, by financially hedging the transaction. Tr. 942. Therefore, the index and its parameters may be established outside the rate case, but only where the foregoing and other specific criteria are met, and only at BPA's discretion. Miller *et al*., WP-02-E-BPA-46, at 26. Finally, BPA anticipates that few, if any, non-aluminum DSIs will seek to have an indexed rate. *Id*.

<u>Evaluation of Positions</u>

ICNU states that BPA plans to work with the non-aluminum DSI companies to establish an undefined index for creating rates, and refers to this as "deferral ratemaking." ICNU Brief, WP-02-B-IN-02, at 4. ICNU has misconstrued BPA's indexed rate option proposal. In fact, BPA is not proposing to establish any rates outside the rate case, since under BPA's proposal any indexed rate must be fashioned around collecting the same revenues as BPA would collect from the customer under the applicable fixed IPTAC rate. Tr. 942. BPA has proposed that it will consider offering an indexed rate to non-aluminum DSI customers only where the proposed index possesses very specific attributes including: (1) it must represent a commodity in which there is sufficient competition and price transparency, evidenced by a commercially recognized price index; (2) the pricing methodology employed in the index must rely on multiple producers; (3) the index must be used commercially to set settlement terms between producers and consumers; and (4) the index must be capable of use for establishing longer-term prices and for hedging. Miller *et al*., WP-02-E-BPA-46, at 26. The primary purpose for these parameters is to ensure that BPA would be able to enter into a financial transaction that would provide offsetting cash flows to the revenues BPA would receive under the applicable flat, fixed IPTAC rate under the power sales contract with the DSI. Tr. 943.

ICNU argues that this "deferral ratemaking" is most evident with regard to the DSI Elf Atochem. ICNU Brief, WP-02-B-IN-02, at 4. ICNU cites some correspondence from Elf Atochem to BPA regarding the Compromise Approach agreement, in which Elf Atochem states it accepts the Compromise Approach provided that BPA would negotiate with Elf Atochem, among other things, "variable rates tied to the price of Elf Atochem products." *Id*. ICNU concludes from this, and from selective cites to the cross-examination transcript, that BPA has committed to set

Elf Atochem's rates outside the scope of this rate case. *Id*. This conclusion is incorrect for the reasons outlined above. In addition, as BPA witnesses stated at cross-examination, that while any negotiations with a non-aluminum DSI regarding the establishment of an indexed rate would not be subject to a public process,

> [t]he objective that BPA would have in that index rate is to assure that we would collect the cost-based revenue requirement that we would anticipate collecting with the fixed rate.

Tr. 942.

To this end, BPA has proposed four criteria for a non-aluminum DSI indexed rate that make it clear that BPA is not proposing to establish any rates outside the rate case. First, in order to ensure that BPA may hedge any commodity risk associated with the indexed rate if necessary, the proposed index must meet to BPA's satisfaction the criteria outlined in BPA testimony. Tr. 940; Miller *et al*., WP-02-E-BPA-21, at 6. Second, the resulting average rate collected over the rate period must be projected to recover the same revenues as the applicable IPTAC rate. *Id*. Third, because the indexed rate for BPA's DSI customers is being proposed to enhance the prospect of DSI survivability and the jobs associated with DSI operations, the requesting non-aluminum DSI must make a demonstration that their survivability is an issue and that BPA may help assist the survivability through the establishment of an indexed rate. Miller *et al*., WP-02-E-BPA-21, at 6; *see also* Tr. 948-49. And fourth, an indexed rate will be offered only at BPA's discretion. ICNU argues that BPA's proposal violates BPA's governing statutes because the Administrator's decisions regarding rates must be based on the record. ICNU Brief, WP-02-B-IN-02, at 5. However, as noted, BPA has clearly articulated in this rate case the conditions under which it will establish an indexed rate for its non-aluminum DSI customers, the most important of which is that any such rate will be established based on collecting revenues equivalent to the applicable IPTAC rate. ICNU has filed no testimony regarding these conditions.

ICNU argues in its brief on exceptions that the parameters BPA has established for creating a non-aluminum DSI indexed rate are inadequate, and that they do not address the rate design issues which BPA is required to determine in the rate case. ICNU Ex. Brief, WP-02-R-IN-01, at 8. As examples, ICNU lists that the determination of demand charges, load variance charges, billing determinants, and seasonal discounts all would be determined outside the rate case. *Id*. However, none of the items listed by ICNU would be part of an indexed rate. For example, as indicated in the proposed IP-02 rate schedule, there would be no separate demand or energy charges associated with any indexed rate or the IPTAC rates upon which they are based--there is only a single flat energy rate for each month, which would only vary by month as indicated in the proposed schedule, and depending on any variability in the commodity index selected. *See* Appendix 1, at 56, 84-86. Load variance charges under the IP-02 rate, when applicable, are dealt with for all DSI customers as a separate, independent charge in the rate schedule. *Id*. at 59. There would be no seasonal discounts with an indexed rate; the index provides the only variability available. And the only billing determinant applicable to such a rate would be kWhs. Essentially, there are no rate design or other rate elements other than the nature of the index to be used that would be decided bilaterally with the customer. Of course, the parameters of the indexed rate would be dictated by the requirement that BPA recover over the rate period revenues equal to or greater than the IPTAC rate.

Finally, the proposal to establish an indexed rate formula outside the rate case based on a rate established in the rate case is not unique. BPA's existing Variable Industrial Power Rate (VI-96) schedule is virtually identical to BPA's proposal in this rate case for its non-aluminum DSI customers. *See* WP-96-A-02, Appendix, at 48. Among other things, the variable rate formula under VI-96, which is available for that portion of DSI load used in primary metal reduction, is based on the IP-96 rate, but the individual rate formulas, including all rate parameters, are established for each customer at the time contracts are negotiated. *Id*.

Decision

BPA is not establishing rates for its non-aluminum DSI customers outside of this rate case, but rather will offer, at its discretion and under specified circumstances, indexed rates that are designed to recover revenues equivalent to the applicable IPTAC rate.

Issue 4

Whether BPA's proposal regarding the Indexed IP rate is discriminatory because BPA is offering indexed rates to only its DSI customers and not to non-DSI industries.

Parties' Positions

ICNU argues that BPA's proposal to offer indexed rates to only its DSI customers is arbitrary, capricious, an abuse of discretion, and not in accordance with the law. ICNU Brief, WP-02-E-IN-02, at 11. ICNU argues that the failure by BPA to offer comparable rates to industrial customers of public agencies is discriminatory, and BPA may not discriminate among similarly situated customers unless it can justify the distinction between DSI and non-DSI companies, and that BPA has failed to do so. *Id*. at 12-13. ICNU proposed that BPA should offer an indexed (also referred to as "variable") rate to all large industrial electric users in the Northwest based on the market price of their respective products. Wolverton, WP-02-E-IN-01, at 1. ICNU argues it is more important to provide a variable rate to the non-DSI industries than to the DSIs, because non-DSI industries comprise a substantially larger part of the economy, both in terms of breadth of geographic scope and in terms of number of employees, than do the DSIs. *Id*. at 7. ICNU testified that if BPA decides to hedge its aluminum price risk associated with the indexed rate proposal to the aluminum smelters, that adding the hedging of non-aluminum prices should reduce the risk faced by BPA by broadening the scope of the risk. *Id*. at 9. ICNU argues that BPA should either offer additional variable rates tied to price indices that reflect the commodities produced by industrial customers of public agencies, or withdraw its proposal to offer variable rates to the DSIs. ICNU Brief, WP-02-B-IN-02, at 14.

In its brief on exceptions ICNU recasts its argument, and argues that by failing to offer an indexed rate to ICNU industries BPA is discriminating not only against those industries, but against BPA public preference customers. ICNU Ex. Brief, WP-02-R-IN-01, at 5-6. They argue that BPA must consider and evaluate whether publicly owned utilities have a right to buy an indexed IP-type product for their industrial customers. *Id*. at 2. ICNU also argues that BPA's statutes prohibit undue discrimination "by implication," and that section 7(c) of the Northwest Power Act in particular provides support for the proposition that Congress intended DSI and non-DSI industries to be similarly situated with respect to rates. *Id*. at 4. ICNU also argues that BPA misconstrued in the Draft ROD its arguments regarding the application of *Association of Public Agency Customers v. BPA*, 126 F.3d 1158 (9th Cir. 1997)(APAC), and that BPA erroneously assumed ICNU argued in its initial brief that *APAC* required that BPA power rate decisions should be examined pursuant to the Transmission System Act. 16 U.S.C. §838-838(k).

The IOUs disagreed that BPA should offer variable rates to all large industrial electric users in the Northwest. Hoff *et al*., WP-02-E-AC/GE/IP/MP/PL/PS-13, at 5. The IOUs argued that such an offering is unnecessary because the services provided by such a rate could be purchased elsewhere, and that industries would choose to purchase from BPA under such a rate only if BPA made an error of pricing. *Id*. The IOUs disagreed with ICNU that the failure to offer a variable rate to non-DSI industries would constitute impermissible discrimination. *Id*. at 6. They argued that the DSIs are a special class of customer under the Northwest Power Act and therefore, can and must be treated differently. *Id*.

<u>BPA's Position</u>

BPA's proposal to offer an indexed rate option to its DSI customers does not legally obligate BPA to provide an indexed rate option to non-DSI industries. The industrial customers of public agencies are not "similarly situated" to the DSIs, but even if they were, there is no anti-discrimination standard applicable to the Administrator's decisions regarding service to the DSIs. Nor is it clear that BPA could enter into a rate relationship of the nature proposed by ICNU with any retail industrial load other than the existing DSIs. Miller *et al*., WP-02-E-BPA-46, at 26; 16 U.S.C. §839c(d)(2). Even if BPA could adopt ICNU's proposal and establish distinct rates for non-DSI retail industrial load, there appears to be little advantage in such a rate proposal to the non-DSI industries or to BPA or its other customers. Miller *et al*., WP-02-E-BPA-46, at 26 *et seq*.

BPA agrees the ICNU industries are important to the region's economy, but ICNU's testimony does not provide any analysis of the effect of BPA power prices on the ability of the ICNU industries to continue to operate, or even show any general concern for the survivability of these industries absent a BPA-sponsored indexed rate. *Id*. at 27. In addition, BPA is proposing to serve the public utilities that serve the ICNU industries with FY 2002-2006 PF power rates that are far below market rates, and at average rates below those proposed for BPA's DSI customers. *Id*. at 29. This fact alone makes it difficult to comprehend how the ICNU industries are being discriminated against by BPA, and there is no apparent reason why these industries cannot propose to their serving utilities that they be offered a variable rate. *Id*.

Finally, BPA does not agree with ICNU that a strategy of a variable rate for multiple industries is a suitable means of diversifying BPA's indexed rate risk. *Id*. In fact, such a proposal would tend to intensify the effects of the business cycle on BPA's revenues, intensifying BPA's other market related risks in times of low or no economic growth. *Id*.

Evaluation of Positions

ICNU argued in its testimony that BPA should offer "variable rates to all large industrial electric users in the Northwest," Wolverton, WP-02-E-IN-02, at 1; but in its initial brief stated that BPA must offer a "comparable variable rate to industrial customers of public agencies." ICNU Brief, WP-02-B-IN-02, at 12-14. For purposes of this evaluation, BPA will assume that ICNU is arguing that BPA must offer an indexed rate option, similar to the proposed indexed IP rate option, to industrial customers of public agencies, and not to all large industrial electric users in the Northwest.

ICNU argues that BPA's failure to offer indexed rates to the industrial customers of public entities is arbitrary and capricious, since such failure constitutes undue discrimination against those industrial customers. ICNU Brief, WP-02-B-IN-02, at 11. ICNU's argument that BPA must offer an indexed rate to the industrial customers of public agencies is premised on ICNU's conclusion that the DSIs and the industrial customers of public agencies are "similarly situated." *Id*. at 12. ICNU argues that the DSIs have historically received unique treatment because of the initial 20-year power sales contracts offered to the DSIs under the Northwest Power Act, but that when those contracts or their replacements expire in September 2001, the industrial customers of public agencies will be similarly situated to DSIs and therefore must be offered a comparable variable rate, absent some justification from BPA for not offering them such a rate. *Id*. at 12-13.

ICNU's analysis is flawed. ICNU cites *Association of Public Agency Customers v. Bonneville Power Admin.*, 126 F.3d 1158 (9th Cir. 1997) (*APAC*) to support its contention that the industrial customers of public agencies and the DSIs will become "similarly situated" upon the expiration of BPA's initial contracts with the DSIs. ICNU Brief, WP-02-B-IN-02, at 12-13. ICNU's reliance on *APAC* is misplaced. In *APAC*, the issue before the court was whether section 6 of the Transmission System Act, 16 U.S.C. §838, §838d, precludes BPA from offering to wheel non-Federal power to the DSIs without also offering the same service to ICNU's members ("APAC" was the prior acronym for ICNU). *APAC*, at 1171. The issue concerned an express anti-discrimination provision in the Transmission System Act regarding BPA's provision of transmission wheeling services to its utility customers, but ICNU has not demonstrated how this analysis applies to its conclusion that if BPA offers an indexed rate option to the DSIs it must provide a comparable indexed rate option to the industrial customers of public agencies. BPA did not propose the indexed IP rate option under section 6 of the Transmission System Act. In any case, the court held that section 6 applied only to discrimination among utilities, and therefore did not apply to either the DSIs or the ICNU industries. *Id*.

The court then stated that even if section 6 of the Transmission System Act did apply to these entities, BPA's actions in offering wheeling contracts to the DSIs but not the ICNU industries would be fully justified under the "unjust, unreasonable, or unduly discriminatory or preferential" standard in the Federal Power Act. *See* 16 U.S.C. §824k(i)(1)(B)(ii). ICNU is correct that the court concluded that the DSIs and the ICNU industries were not "similarly situated," because of the ability of the DSIs to terminate their 1981 contract with BPA on one year's notice. However, as noted above, BPA is not proposing the indexed IP rate option under section 6 or any other provision in the Transmission System Act, and the Federal Power Act standard is applicable only to BPA's transmission rates, not its power rates or to the

Administrator's decisions regarding whether to offer power services to some customers and not others. ICNU argues in its brief on exceptions that this analysis erroneously assumes ICNU argued in its initial brief that BPA's rate proposal should be examined pursuant to the Transmission System Act. ICNU Ex. Brief, WP-02-R-IN-01, at 3. BPA understands ICNU's argument to be that under different circumstances (that is, where ICNU industries are similarly situated to DSIs), *APAC* indicates that anti-discrimination standards would apply to BPA's power ratemaking decisions. However, the fact remains that the only anti-discrimination provisions discussed by the court in *APAC* are those contained in the Transmission System Act and Federal Power Act with respect to transmission rates. Whether ICNU's reading of *APAC* is correct or not ultimately is irrelevant, since neither of those anti-discrimination standards applies to BPA power ratemaking decisions. *APAC's* analysis focused on ICNU's claim that its members were similarly situated to DSIs for purposes of BPA transmission service and rates, not on whether non-DSI industries could be similarly situated to DSIs for purposes of power service and rates from BPA. Therefore, the "similarly situated" analysis by the court has no application to BPA's proposal for service to the DSIs in this rate case. Even if it did, the court held that ICNU's members are not customers of BPA. *APAC*, 126 F.3d 1158, 1172.

Even if the "similarly situated" analysis did apply in this case, the fact that the initial long-term contracts (or their successors) offered to the DSIs in 1981 pursuant to section 5(d)(1)(B) of the Northwest Power Act (16 U.S.C. §839c(d)(1)(A)) expire in September 2001 does not automatically strip an existing DSI of its direct customer status under the Northwest Power Act. The Administrator has the discretion, but not the obligation, to continue to serve the DSIs directly after September 2001. *See infra*, at 15.5.3. Existing DSIs remain an exclusive class of industrial customers that the Administrator is authorized to serve directly. Even ICNU argued in *APAC* that its industrial customer members would be "similarly situated" in 2001 only if BPA no longer served the DSIs, not merely because BPA no longer had an obligation under section 5(d) of the Northwest Power Act to serve the DSIs. *APAC*, 126 F.3d 1158, 1172. Therefore, ICNU's conclusion that the DSIs and the industrial customers of public utilities will be "similarly situated" because the initial DSI contracts will expire in September 2001 is incorrect and not supported by *APAC*.

ICNU argues in its brief on exceptions that, in fact, it suggested in its initial brief that several power ratemaking provisions in BPA's statutes "by implication" prohibit undue discrimination. ICNU Ex. Brief, WP-02-R-IN-01, at 3. Specifically, ICNU cites sections 7(a) and 7(g) of the Northwest Power Act. 16 U.S.C. §839e(a)(1), §839e(g). ICNU notes that section 7(a), among other things, requires that BPA establish rates consistent with "sound business principles." However, ICNU does not explain how this clause in section 7(a) rises to the level of an anti-discrimination directive. To the contrary, as indicated elsewhere, BPA believes proposing variable rates for multiple industries would tend to intensify the effects of the business cycle, making BPA's other risk areas more susceptible in times of low or no economic growth. Miller *et al*., WP-02-E-BPA-46, at 27. Taking such action would not be consistent with "sound business principles." ICNU also notes that section 7(g) requires BPA to allocate certain power costs consistent with "generally accepted ratemaking principles." Again, ICNU fails to tie this clause of section 7(g) to BPA's indexed rate proposal in this case. In fact, section 7(g) applies only to the allocation of certain costs not otherwise allocable under the power rate directives in section 7 of the Northwest Power Act, and so has no application as a broader anti-discrimination standard.

In addition, ICNU now cites section 7(c) of the Northwest Power Act (16 U.S.C. §839e(c)(1)(B)) for the proposition that Congress intended the DSIs to be similarly situated to ICNU member industries with respect to rates, and that it is therefore appropriate to apply a traditional "discrimination" standard to analyze the rates BPA offers to the DSIs. ICNU Ex. Brief, WP-02-R-IN-01, at 4. Section 7(c)(2) provides that DSI rates set under that provision be "equitable in relation to the retail rates" charged by BPA's public preference customers to their industrial customers in the region. However, ICNU does not explain how this provision compels BPA to offer non-DSI industries the same type of rates offered to the DSIs. Section 7(c)(2) requires only that the rates under that section be based on the applicable PF rate, plus a typical margin applied by BPA's public preference customers to the rates they charge their industrial customers. The proposed fixed IPTAC rates have been established consistent with this provision, but ICNU reads more into section 7(c)(2) than is there when it argues that this provision also requires BPA to offer non-DSI industries an indexed rate.

ICNU also argues that BPA, through its failure to offer more widely an industrial indexed rate, not only is discriminating directly against non-DSI industries that are similarly situated to the DSIs, but that BPA is also discriminating against its public preference customers. ICNU Ex. Brief, WP-02-R-IN-01, at 5. ICNU contends that BPA is discriminating "against the one class of customers who have permanent, statutory, preference rights to federal power." *Id.* at 6. Principally, public preference gives BPA's public body and cooperative customers the right to have their net full requirements met by BPA before BPA makes sales to non-preference customers, but ICNU fails to draw any connection between this preference right and a right to an indexed rate. No party has argued that its preference rights have been violated in the way alleged by ICNU, and in fact no other party in the rate case has supported ICNU's position that BPA should offer non-DSIs an indexed rate. ICNU's attempt to invoke the preference provisions to get an indexed industrial rate for non-DSI industrial customers served by public agencies is completely unavailing, if for no other reason than no public preference customer supports ICNU's position.

ICNU's proposal also appears to be inconsistent with section 5(d)(2) of the Northwest Power Act. 16 U.S.C. §839c(d)(2). Section 5(d)(2) provides that "[t]he Administrator shall not sell electric power, including reserves, directly to new direct service industrial customers." Notwithstanding ICNU's statements to the contrary in its brief on exceptions, ICNU's proposal clearly contemplates the formulation by BPA of distinct retail industrial rates for non-DSI industries, with BPA's public utility customers acting as a mere conduit for delivery and billing purposes. ICNU states that the variable rates need not be offered directly to public agency industrial customers, but that BPA could allow the public agency customer to purchase the variable rate power on behalf of the industrial customer. ICNU Brief, WP-02-B-IN-02, at 14; ICNU Ex. Brief, WP-02-R-IN-01, at 2. This suggestion, however, would essentially make a sham of the prohibition contained in section 5(d)(2).

The prohibition on BPA entering into direct sales relationships with new industrial customers must be read to go beyond merely limiting its ability to deal directly with new industrial customers, as suggested by ICNU. If that were the only prohibition, there would be nothing to prevent BPA from establishing a direct retail rate relationship with any industrial customer in the Northwest as long as the power was delivered to the retail industrial customer through a third-party utility or marketer, with that third party also serving as the surrogate bill collector. ICNU is proposing that BPA create individualized retail level rates for the industrial customers of public agencies. *See* Wolverton, WP-02-E-IN-01, at 1 *et seq*. However, BPA's relationship with such industrial customers is limited by section 5(d)(2) to meeting the net requirements of its preference customers with industrial load at the applicable wholesale rate. In order to have any meaningful application, the prohibition in section 5(d)(2) must be read to preclude BPA from establishing a direct retail-level rate relationship with any industrial load other than with the DSIs that had BPA contracts at the time of enactment of the Northwest Power Act. The retail-level rates paid by the industrial customers of public utilities are a matter between the industrial customer and its serving public utility. The practical effect of ICNU's proposal, and its argument that the industrial customers of public agencies are "similarly situated" to the DSIs, is to boot-strap those industrial customers into quasi-DSI status customers. This is contrary to Congress's express intent in section 5(d)(2). *See also* H.R. Rep. No. 96-976, pt. 1, at 63 (1980).

ICNU goes on to argue that BPA has provided no justification for discriminating against the industrial customers of public agencies. ICNU Brief, WP-02-B-IN-02, at 13. They note that BPA conducted a survivability analysis only for the aluminum smelter DSIs, but that BPA has proposed also to offer indexed variable rates to any non-aluminum DSI. *Id*. They argue that BPA's survivability standard could just as easily be applied to industrial customers of public agencies, and that because they make up a substantially larger part of the economy, it is more important to provide a variable rate to such non-DSI industries than it is to provide a variable rate to the DSIs. *Id*. 13-14. As outlined above, the industrial customers of public agencies are not "similarly situated" to the DSIs, and even if they were, the anti-discrimination provisions of the FPA do not apply in this case. BPA has no obligation, and perhaps no statutory authority, to offer the industrial customers of public agencies an indexed rate option.

With respect to ICNU's observation that BPA did not conduct any survivability analysis for non-aluminum DSIs, BPA proposed that the indexed rate will be made available to non-aluminum DSIs as a tool to aid their survival during times of low product prices, Miller *et al*., WP-02-E-BPA-21, at 6, and that any non-aluminum DSI that requested an indexed rate from BPA would need to demonstrate to BPA that its survivability was an issue and that an indexed rate would help assist its survivability. Tr. 949. Even if the industrial customers of public agencies were similarly situated to DSIs, ICNU failed to provide any analysis of the effect of BPA power rates on the ability of the ICNU industries to continue to operate, or even show any general concern for the survivability of the ICNU industries absent such a rate proposal from BPA. Miller *et al*., WP-02-E-BPA-46, at 27. In addition, BPA established that proposing variable rates for multiple industries would tend to intensify the effects of the business cycle, making BPA's other risk areas more susceptible in times of low or no economic growth. *Id*. at 29. This would very likely place greater pressure on BPA to meet its cost recovery and Treasury repayment obligations. *Id*.

Finally, BPA is proposing to provide power in the 2002-2006 rate period to many utilities that serve the ICNU industries at prices that are far below market rates, and at average rates below those charged to BPA's DSI customers. *Id*. In addition, BPA has proposed a cost-based indexed PF rate available to the utilities serving many ICNU member industries. *Id*. These facts alone demonstrate that the industrial customers of public agencies are not being discriminated against by BPA vis-à-vis the DSIs, even if a discrimination standard applied.

<u>Decision</u>

The industrial customers of public entities are not "similarly situated" to the DSIs, and BPA's proposal to offer indexed rates to the DSIs and not the industrial customers of public entities does not constitute undue discrimination and is not arbitrary or capricious.

11.0 RESIDENTIAL EXCHANGE AVERAGE SYSTEM COSTS, LOAD FORECASTS AND POLICY

11.1 Introduction

Many of the following arguments were raised in the parties' initial briefs and are identical to the arguments raised in their briefs on exceptions. BPA will retain citations to the parties' initial briefs in the discussions in this chapter, and may not add additional citations to briefs on exceptions unless new or different arguments are presented.

The Northwest Power Act, 16 U.S.C. §839 *et seq*., created the REP to provide residential and small farm customers of PNW utilities a form of access to low-cost Federal power. Boling and Doubleday, WP-02-E-BPA-30, at 1-5. Under the Northwest Power Act, BPA "purchases" power from each participating utility at that utility's ASC. *Id.* The Administrator then offers, in exchange, to "sell" an equivalent amount of electric power to the utility at BPA's PF Exchange power rate. *Id.* The amount of power purchased and sold is the qualifying residential and small farm load of each utility participating in the REP. *Id.* The Northwest Power Act requires that the net benefits of the REP be passed on directly to the residential and small farm customers of the participating utilities. *Id.*

The REP does not involve a conventional purchase and sale of power. *Id.* Under the normal implementation of the REP, no actual power is transferred either to or from BPA. *Id.* The "exchange" has been referred to as a "paper" transaction, where BPA provides the participating utility cash payments that represent the difference between the power "purchased" by BPA and the less expensive power "sold" to the participating utility. *Id.* As discussed below, however, actual power sales may occur under "in-lieu" transactions, where BPA purchases power from a source other than the utility and sells actual power to the utility. *Id.*

With regard to the current status of the REP, Residential Exchange Termination Agreements have been negotiated with all but one of the previously active exchanging utilities. *Id.* The only remaining utility with an "active" Residential Purchase and Sale Agreement (RPSA) is MPC, which receives no REP benefits. *Id.* MPC continues to be in "deemer" status. *Id.* When a utility's ASC is less than the PF Exchange Program rate, the utility may elect to deem its ASC equal to the PF Exchange Program rate. *Id.* By doing so, it avoids making actual monetary payments to BPA. *Id.* The amount that the utility would otherwise pay BPA is tracked in a "deemer account." *Id.* At such time as the utility's ASC is higher than BPA's PF Exchange rate, benefits that would otherwise be paid to the utility act as a credit against the negative "deemer balance." *Id.* Only after the "positive benefits" have completely offset the "negative balance," bringing the negative "deemer account" to zero, would the utility again receive actual monetary payments from BPA. *Id.* Avista Corporation (Avista) and Idaho Power both terminated their RPSAs in 1993. *Id.* The issue of deemer balances with these utilities is currently in dispute. *Id.*

Each exchanging utility's ASC is determined by the Administrator according to the 1984 ASC Methodology, an administrative rule developed by BPA in consultation with its customers. *Id.* A utility's ASC is the sum of a utility's production and transmission-related costs (Contract

System Costs) divided by the utility's system load (Contract System Load). *Id.* A utility's system load is the firm energy load used to establish retail rates. *Id.* While BPA has used the ASC Methodology for its ASC determinations, it should be noted that the ASC Methodology can be revised. *Id*. Regional IOUs have advocated the revision of the ASC Methodology to eliminate the changes made in 1984. *Id.* In the event that the ASC Methodology were revised in the manner advocated by the IOUs, forecasted exchange benefits would increase significantly. *Id.*

BPA uses a "jurisdictional approach" in determining utilities' ASCs, which relies upon cost data approved by state public utility commissions (in the case of IOUs) and utility governing bodies (in the case of public utilities) for retail ratemaking. *Id.* These data provide the starting point for BPA's determination of the ASC of each utility participating in the REP. *Id.* Costs that have not been approved for retail rates are not considered for inclusion in Contract System Costs. *Id.*

The schedule for filing and reviewing a utility's ASC is established in the 1984 ASC Methodology, which provides that "not later than five working days after filing for a jurisdictional rate change or otherwise commencing a rate change proceeding, the utility shall file a preliminary Appendix 1, setting forth the costs proposed by the utility and shall deliver to BPA all information initially provided to the state commission." *Id.* The filing includes all testimony and exhibits filed in the retail rate proceeding. *Id.* Not later than 20 days following the effective date of new rate schedules in a jurisdiction, the utility must file a revised Appendix 1 reflecting costs as approved by the state commission or utility governing body. *Id.* BPA then has 210 days to review the filing and issue a report signed by the Administrator. *Id.* During this review process, BPA ensures that the costs and loads conform to the rules and requirements of the ASC Methodology, as well as the applicable provisions of the Northwest Power Act. *Id.* BPA makes adjustments as necessary. *Id.*

The gross cost of the REP is the total dollar amount that BPA pays for the power it "purchases" from participating utilities, including utilities in deemer status. *Id.* In the case of an in-lieu transaction, as discussed in Issue 4 below, the gross cost of the REP includes the cost of an in-lieu resource. *Id.* The gross revenue is the total dollar amount that BPA receives from participating utilities for its subsequent "sale" of power to them at the PF Exchange rate. *Id.* The net cost of the Program is the difference between gross cost and gross revenue, plus the Program implementation costs. *Id.*

BPA assumes that the REP will continue to exist during the rate period. *Id.* However, BPA's Subscription Strategy proposes a settlement of the REP for IOUs that includes a power sale and a financial component. *Id.* Because BPA does not know whether eligible utilities will continue participation in the REP or agree to a settlement of the REP, BPA must establish a rate that applies to the continued implementation of the REP. *Id.*

11.2 Forecast of Average System Cost and Loads for Exchanging Utilities

In the past, an exchanging utility's ASC forecast was typically based on the costs included in its last approved ASC Report signed by the Administrator. Boling and Doubleday, WP-02-E-BPA-30, at 5. Such costs were then adjusted to account for inflation, power purchases, and resource additions, and applied to forecasted loads for future periods to calculate the forecasted ASC. *Id.* Because of the Residential Exchange Termination Agreements noted above, BPA no longer receives cost and load data from utilities through ASC filings as was previously required and provided under the RPSAs. *Id.* BPA has therefore used a variety of data sources and approaches to determine ASCs. *Id.*

BPA's first step in developing ASCs was to identify which of BPA's many public agency and IOU customers might have ASCs that would be high enough to ensure positive exchange benefits and should therefore be evaluated in detail. *Id.* at 6. Utilities that executed Residential Exchange Termination Agreements that extend through 2011 were eliminated. *Id.* BPA then determined a proxy for the new PF Exchange rate. *Id.* Utilities' ASCs would need to exceed this rate in order to receive positive exchange benefits. *Id.* In developing the proxy rate, BPA noted that the section 7(b)(2) rate test triggered in BPA's 1996 rate case, and the 1996 PF Exchange rate was 32.7 mills/kWh. *Id.* BPA then reviewed some of the fundamental elements of the 1996 section 7(b)(2) rate test to determine whether it was likely that the trigger for the PF-02 rate period would be similar, and therefore the PF Exchange rate would be similar. *Id.* BPA noted that BPA's generation costs after revenue credits had remained relatively flat since the 1996 rate case; that exchanging utilities' ASCs were increasing over time; and that the value of reserves credit for the DSIs had diminished. *Id.* These factors suggested that the new trigger amount and the new PF Exchange rate would likely be at least as high as the previous trigger amount and 1996 PF Exchange rate. *Id.* Based on ASCs that were current or forecasted at the time the Residential Exchange Termination Agreements were negotiated, BPA assumed that Puget Sound Energy (PSE), PGE, the Pacific Power and Utah Power Divisions of PacifiCorp, and MPC might have relatively high ASCs. *Id.* In addition, as discussed in greater detail below, BPA used simplifying assumptions to estimate whether Avista and Idaho Power were likely to be candidates for Exchange benefits during the rate period. *Id.* Among public utilities, Clark County Public Utility District (PUD), Snohomish County PUD, and the City of Idaho Falls were considered possible candidates to have relatively high ASCs. *Id.* Each utility has generating resources and had a relatively high ASC at the time it negotiated a Residential Exchange Termination Agreement. *Id.* at 6-7.

To forecast ASCs for PacifiCorp (the Pacific Power and Utah Power Divisions), PSE, PGE, and MPC, BPA developed a Microsoft Excel-based model to replace the ASC forecasting function that was performed by a mainframe computer model in BPA's 1996 rate case. *Id.* at 7. BPA developed a new model for a number of reasons. *Id*. The mainframe model was expensive to maintain and to run. *Id.* The model was also difficult for parties in BPA's rate case to understand and replicate. *Id.* Desktop computer technology had improved to where it was possible to build spreadsheet-based models that could perform many of the applications of the mainframe model. *Id.*

The ASC forecasting methodology of the new model is consistent with the old model. *Id.* The new model adjusts costs to account for price changes and inflation, replaces and depreciates production plant based on historical activity, and accounts for power purchases and sales. *Id.* The new model, however, is simpler to operate than the old model. *Id*. The new model, unlike the old model, does not calculate gross cost, gross revenue, and net cost as they are applied to the REP. *Id.* This function is now calculated by an Exchange cost model linked to the RAM, which simplifies the iterative process required to achieve stable PF rates and Exchange costs. *Id. See* Wholesale Power Rate Development Study, WP-02-E-BPA-05, section 3.2.1.3.

The starting point expense data used as the basis for forecasting rate period ASCs are essentially the same data used in BPA's 1996 rate case. Boling and Doubleday, WP-02-E-BPA-30, at 7. Plant replacement factors have been adjusted to reflect the most current five years of plant retirement activity, and expenses have been adjusted using current escalators. *Id.* In addition, given possible industry restructuring and uncertain market conditions, BPA assumed for ASC forecasting purposes that utility load growth will be satisfied with purchased power. *Id.* at 7-8. Such purchases are assumed to be at 28.1 mills/kWh, BPA's forecast of five-year flat-block purchases, plus a transmission charge. *Id.* at 8. The testimony of Oliver *et al.*, WP-02-E-BPA-20, describes the derivation of the five-year flat-block price forecast. *Id. See also* ROD section 10.11. This forecast is appropriate, because exchanging utilities will make long-term purchases to meet load growth. Boling and Doubleday, WP-02-E-BPA-30, at 7. BPA based the transmission charge on the PTP rate (currently $1.00 per kW-month), which was assumed to increase to $1.48 per kW-month in BPA's next TBL rate case. *Id.* The $1.48 rate was assumed to be constant through FY 2010. *Id.* BPA then assumed an energy loss rate of 2 percent and flat delivery. *Id.* Converting these adjustments to an energy-only charge resulted in a rate of 2.07 mills/kWh. *Id.* BPA then assumed that the foregoing energy losses were valued at 28.1 mills/kWh, resulting in a cost of transmission with losses of 2.63 mills/kWh in FY 2002. *Id.*

BPA has adjusted PGE's Contract System Costs based on the functionalization of certain benefits from PGE's merger with Enron, as directed by the OPUC in Order Number 97-196. *Id.* The OPUC's order specified that $105 million in benefits relating to use of PGE's name and other intangibles be distributed with interest over eight years beginning in 1997. *Id.* The order further specified that $36 million in cost of service savings be distributed with interest over four years beginning in 1998. *Id.* Based on the ratio of exchangeable plant in service to total plant in service (the "PTDG ratio") taken from PGE's ASC filing that was suspended when PGE's Residential Exchange Termination Agreement was negotiated, BPA assumed that 60 percent of such merger benefits would reduce Contract System Costs. *Id.* This results in a $9.7 million reduction to PGE's Contract System Costs during the first three years of BPA's rate period, FY 2002-2004. *Id.*

The test years of the most recent ASC filings for Avista and Idaho Power are 1983 and 1984, respectively. *Id.* at 9. With such old data, BPA estimated proxy ASCs for 1997. *Id.* BPA determined prior ASCs as a percentage of average residential revenue per kWh sold for the test years and applied those percentages to average residential revenue per kWh sold for 1997. *Id.* The post-1997 ASCs for Avista and Idaho Power were escalated at 2.5 percent annually. *Id.* This escalation rate is equal to the simple average annual rate of growth in ASC for MPC, PGE, PSE, and the Pacific Power and Utah Power divisions of PacifiCorp for the FY 1999-2010 period. *Id.*

Load forecasts for PacifiCorp and PGE were based on data submitted by the utilities and used in BPA's 1996 rate case. *Id.* Load forecasts that did not extend through FY 2010 were escalated at average annual rates of growth during the utility's forecast period. *Id.* Load forecasts for MPC and PSE are based on utility forecasts submitted to BPA in March 1998. *Id.* Loads for Idaho Power were estimated from publicly available data in early 1998. *Id.* Residential loads for Avista were estimated by reviewing current total utility load data and residential loads that had been provided by Avista for FY 1995. *Id.*

Because Clark County PUD, Snohomish County PUD, and the City of Idaho Falls terminated their RPSAs so long ago, it is unwise to project such obsolete cost data ahead 10 or more years just to determine ASCs for the first year of BPA's rate period. *Id.* Instead, with the cooperation of utility staff, BPA staff estimated current ASCs for Clark and Idaho Falls using BPA's Excel-based ASC evaluation template. *Id.* Such ASCs were then escalated at 2.2 percent annually through FY 2010. *Id.* This escalation factor is lower than the escalation factor applied to Avista's and Idaho Power's ASCs, described above. *Id.* The escalator applied to Avista and Idaho Power is significantly influenced by the assumption that load growth is satisfied by purchases at 28.1 mills/kWh. *Id.* Clark and Idaho Falls have access to BPA's preference power at rates lower than BPA's five-year flat-block price forecast for their net requirements. *Id.* at 9-10. To estimate the effect of lower purchased power costs on ASC, BPA determined the simple average annual rate of growth in ASC for MPC, PGE, PSE, and the Pacific Power and Utah Power divisions of PacifiCorp for the FY 1999-2010 period, substituting the PF-96 rate for the higher 28.1 mills/kWh price that was used to estimate the IOUs' ASCs. *Id.* at 10. Using the lower PF-96 rate for load growth-driven purchased power yielded the lower escalation rate for Clark and Idaho Falls. *Id.* Both Clark and Idaho Falls provided current load forecasts. *Id.*

Using 1997 annual report data, Snohomish PUD's ASC was estimated to be 30.87 mills/kWh. *Id.* Snohomish's ASC effective October 1, 2001, is estimated to be 30.07 mills/kWh. *Id.* This reduction is largely based on assumptions of reduced purchased power costs. *Id.* Snohomish's ASC was then escalated at the same annual rate, 2.2 percent, that was applied to Clark and Idaho Falls. *Id.*

Issue 1

Whether BPA properly included transmission costs in its development of ASC forecasts.

Parties' Positions

The DSIs argue that BPA used excessive ASC estimates for the IOUs, such as by relying on stale, dated data. DSI Brief, WP-02-B-DS-01, at 66; DSI Ex. Brief, WP-02-R-DS-01, at 2-66. The Joint DSIs argued that BPA has improperly included transmission costs in the development of its ASC forecasts. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 18; DSI Ex. Brief, WP-02-R-DS-01, at 2-67.

BPA's Position

BPA has properly included transmission costs in its development of ASC forecasts. Boling and Doubleday, WP-02-E-BPA-30, at 5-10; Boling and Doubleday, WP-02-E-BPA-53, at 8-12.

Evaluation of Positions

The DSIs argue that BPA used excessive ASC estimates for the IOUs by relying on stale, dated data. DSI Brief, WP-02-B-DS-01, at 66. The individual arguments regarding ASCs that were raised by the DSIs are addressed in greater detail below.

The Joint DSIs argued that the transmission costs BPA has included in ASCs are incorrect because, due to the Energy Policy Act of 1992 (EPA-92) and FERC Order 888, BPA has the means to determine which transmission costs are resource costs for purposes for inclusion in a utility's ASC and which are not. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 18. ASCs must be established consistent with BPA's ASC Methodology. Boling and Doubleday, WP-02-E-BPA-53, at 8. BPA has properly included transmission costs in its ASC forecasts. *Id.* While the ASC Methodology may be changed in the future, BPA has an existing methodology, and it is not known what possible changes would be made in developing a subsequent methodology. *Id.* It is therefore, appropriate for purposes of this rate proceeding to use the current ASC Methodology in making ASC forecasts. *Id.* BPA's forecasted ASCs include transmission costs that have been (or would be) allowed consistent with the current ASC Methodology, escalated based on assumptions regarding inflation and plant additions and retirements. *Id.* Basing ASC forecasts on transmission costs that are determined to be resource costs due to EPA-92 and FERC Order 888 would be inconsistent with the ASC Methodology. *Id.*

The Joint DSIs argued that all costs that FERC allows a utility to recover under its open access transmission tariff should be excluded from a utility's ASC, and all transmission costs FERC assigns to generation for ratemaking purposes should be allowed as part of a utility's ASC. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 18. As noted above, ASCs must be determined in accordance with BPA's ASC Methodology. Boling and Doubleday, WP-02-E-BPA-53, at 8. The Joint DSIs' proposal would require that BPA's ASC forecasts determine exchangeable transmission costs differently than prescribed by the current ASC Methodology. *Id.* While the Joint DSIs may advocate changes in the determination of eligible costs in a future proceeding to develop a new ASC Methodology, BPA's forecasts are properly based on the requirements of the current ASC Methodology rather than a speculative new methodology. *Id.* at 8-9.

The Joint DSIs argued that the estimation of generation-integration and generator step-up transformation costs for utilities should be based on the same percentage of those costs to transmission costs for BPA, which is 2.8 percent. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 19. Again, the Joint DSIs' recommended approach is inconsistent with the current ASC Methodology, which is properly used for the forecast of exchange costs in this rate proceeding. Boling and Doubleday, WP-02-E-BPA-53, at 9.

The Joint DSIs' estimates of the ASCs of exchanging utilities included generation-integration and GSU costs, but because BPA's PF Exchange rate is a delivered rate, they added BPA's transmission costs to their forecasted ASCs to compute the net cost of the exchange and did not assume that additional transmission costs would be exchanged. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 19. Since the PF Exchange rate is a delivered rate, it is appropriate that ASCs include transmission costs when determining net exchange costs. Boling and Doubleday, WP-02-E-BPA-53, at 9. The Joint DSIs, however, essentially have substituted BPA's transmission costs in the ASC determination for the utilities' own transmission costs. *Id.* This approach is inconsistent with the current ASC Methodology. *Id.*

The Joint DSIs argued that BPA should not include any estimate of its own transmission costs other than GI and GSU costs when it forecasts the net cost of the exchange; that is, the PF Exchange rate should be developed to be a power-only rate. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 19. Utilities' ASCs include transmission costs under the current ASC Methodology. Boling and Doubleday, WP-02-E-BPA-53, at 9. Under the traditional implementation of the REP, BPA's PF Exchange rate has also included transmission costs in order to establish an apples-to-apples comparison for purposes of determining exchange benefits. *Id.* Given the current ASC Methodology, it would be inappropriate to exclude transmission costs from the PF Exchange rate. *Id.* at 9-10.

Decision

BPA properly included transmission costs in the development of ASC forecasts.

Issue 2

Whether BPA properly forecasted ASCs for Avista and Idaho Power.

Parties' Positions

The DSIs argue that BPA used excessive ASC estimates for the IOUs, such as by relying on stale, dated data. DSI Brief, WP-02-B-DS-01, at 66. The Joint DSIs argued that BPA improperly calculated the ASCs for Avista and Idaho Power. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 20.

BPA's Position

BPA has properly forecasted ASCs for Avista and Idaho Power. Boling and Doubleday, WP-02-E-BPA-53, at 10-11.

Evaluation of Positions

The Joint DSIs argued that BPA's calculations of ASCs for Avista and Idaho Power are based on an assumption that generation, transmission, and distribution costs are growing in the same proportion, which is not true. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 20. The Joint DSIs argued that it is incorrect to tie the ASC, which is based only on generation and some transmission costs, to any change in the residential rate, which has been driven mainly by changes in distribution costs that are not exchangeable. *Id.* BPA estimated current ASCs for Avista and Idaho Power by adjusting the utilities' last approved ASCs based on changes to the utilities' average residential rates. Boling and Doubleday, WP-02-E-BPA-53, at 10. The DSIs asserted that non-exchangeable distribution costs have been driving changes in Avista's and

Idaho Power's residential rates. *Id.* This, however, is not the case. *Id.* The DSIs' contention was based on an incomplete assumption and incorrect data. *Id.* The DSIs assumed that changes in net plant would be a good indicator of changes in rates and exchangeable costs. *Id.* While this may be one element, it is revenue requirement, not net plant, which drives changes in rates. *Id.* It is true that distribution net plant has grown faster than production and transmission plant for both companies since 1990. *Id.* However, only 62 percent of Avista's and 39 percent of Idaho Power's net plant growth is due to distribution, whereas the DSIs calculated 93 percent and 89 percent, respectively. *Id.* Regardless, changes in net plant do not directly lead to changes in revenue requirements and rates. *Id.* Net plant affects rates through depreciation, interest, and rate of return. *Id.* Such amounts for Avista and Idaho Power are offset or even outweighed by the respective increases that have occurred in production and transmission O&M expense, most of which is directly exchangeable. *Id.* Based on FERC Form 1 data for 1990 and 1998, Avista's production and transmission O&M expense (less purchased power) has increased $58 million, or 53 percent. *Id.* Idaho Power's production and transmission O&M expense (less purchased power) has increased $54 million, or 27 percent. *Id.* at 10-11. Thus, increases in production and transmission O&M expense for the two utilities, most of which is exchangeable, is a more important determinant of ASC than is growth in distribution plant. *Id.* at 11.

The Joint DSIs argued that another problem with BPA's proxy is that it does not take into account the large increase in other revenues that are credited against the ASC, citing Avista and Idaho Power's sales for resale. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 20-21. Avista's growth in sales for resale revenue cited by the DSIs was $362 million. Boling and Doubleday, WP-02-E-BPA-53, at 11. This potential credit against ASC, however, would be more than offset by increased purchased power costs of $404 million. *Id.* Idaho Power's sales for resale revenue growth was $536 million, whereas its purchased power costs increased $496 million. *Id.*

The Joint DSIs attempted to follow the ASC Methodology and develop ASCs for Avista and Idaho Power based on 1998 FERC Form 1 data, including only the production expenses and return on production assets and a portion of transmission costs representing GI and generator step-up transmission, then escalating these 1998 ASCs in the same way BPA escalated the PacifiCorp, PSE, PGE, and MPC ASCs. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 21. Under the current ASC Methodology, BPA does not determine ASCs based on FERC Form 1 data. Boling and Doubleday, WP-02-E-BPA-53, at 11. In fact, when BPA revised the ASC Methodology in 1984, one possible revision considered by BPA involved the use of FERC Form 1 information to determine ASCs. *Id.* This approach was widely criticized by parties and rejected by BPA and is not the basis for determining ASCs under the current ASC Methodology. *Id.* During the implementation of the REP since 1981, BPA has periodically estimated ASCs from FERC Form 1 data and then compared the results to an approved ASC. *Id.* at 11-12. Such estimates consistently differed from approved ASCs, often by large margins and in no predictable direction. *Id.* at 12. Therefore, the DSIs' estimates are likely to be flawed. *Id.* In addition to problems inherent in using FERC Form 1 data, the DSIs used only a portion of transmission costs representing GI and generator step-up transmission in their ASC forecasts. *Id.* As noted above, including only GI and generator step-up transmission costs in ASC is inconsistent with the ASC Methodology. *Id.*

Including only generation-integration and generator step-up transmission costs in ASC, as discussed above, reduced BPA's forecasted five-year rate period ASCs for MPC, PacifiCorp (Pacific Power and Light and Utah Power and Light Divisions), PGE, and PSE by an average of 4.71 mills/kWh. Boling and Doubleday, WP-02-E-BPA-53, at 12. *See* Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 21. Adding this transmission cost component to the five-year average ASCs for Avista and Idaho Power that were estimated by the DSIs results in ASCs of 23.71 mills/kWh and 22.30 mills/kWh, respectively. Boling and Doubleday, WP-02-E-BPA-53, at 12. ASCs at this level would likely have the same effect as the ASCs estimated by BPA, *i.e.,* neither utility is forecasted to receive Residential Exchange benefits under the current proposal. *Id.*

Decision

BPA properly forecasted ASCs for Avista and Idaho Power.

Issue 3

Whether BPA properly forecasted in-lieu transactions for 50 percent of Residential Exchange load.

Parties' Positions

The DSIs argue that BPA should have assumed that it would in-lieu 100 percent of the purchases from certain IOUs under the REP. DSI Brief, WP-02-B-DS-01, at 66-67; DSI Ex. Brief, WP-02-R-DS-01, at 2-66 to 2-68. The DSIs contend that it is inappropriate for BPA to determine the amount of in-lieu transactions based on the goal of providing exchanging utilities additional, non-statutory benefits. DSI Ex. Brief, WP-02-R-DS-01, at 24. PPC argues that there is nothing to prevent BPA from in-lieuing a portion of the utility's eligible exchange load. PPC Brief, WP-02-B-PP-01, at 74.

BPA's Position

BPA has properly forecasted in-lieu transactions for 50 percent of Residential Exchange load. Boling and Doubleday, WP-02-E-BPA-30, at 10-16; Boling and Doubleday, WP-02-E-BPA-53, at 6.

Evaluation of Positions

Under section 5(c)(5) of the Northwest Power Act:

> . . . [T]he Administrator *may* acquire an equivalent amount of electric power from other sources to replace power sold to such utility as part of an exchange sale if the cost of such acquisition is less than the cost of purchasing the electric power offered by such utility.

16 U.S.C. §839c(c)(5) (emphasis added). This acquisition of power from other sources is "in-lieu" of the "purchase" that would otherwise occur under the REP, and is designed to provide a mechanism to limit the net costs of the Program. Boling and Doubleday, WP-02-E-BPA-30, at 10. An in-lieu transaction is not mandatory and is implemented subject to the Administrator's discretion consistent with applicable law and the applicable RPSA. Boling and Doubleday, WP-02-E-BPA-30, at 10. *See* PPC Brief, WP-02-B-PP-01, at 74.

BPA must determine which utilities are candidates for in-lieu transactions. In-lieu transactions are appropriate only for utilities with ASCs that exceed the PF Exchange rate. *Id.* at 11. BPA therefore would not in-lieu utilities with ASCs below BPA's PF Exchange rate. *Id.* In addition, where a utility's ASC is only slightly higher than the PF Exchange rate, it is inappropriate to assume an in-lieu transaction, because forecast error and the costs of implementation could make the in-lieu transaction uneconomic. *Id.* In-lieu transactions therefore, are financially sound only for utilities with ASCs significantly above the PF Exchange rate. *Id.* Finally, in-lieu transactions are financially sound only when the cost of the in-lieu resource is significantly below the utility's ASC. *Id.*

As noted above, the determination of which utilities would be subject to in-lieu transactions rests primarily on three factors: a utility's ASC, the cost of the in-lieu resource, and the PF Exchange rate. BPA's forecast of exchanging utilities' ASCs is discussed above. *Id.* Complete documentation of the exchanging utilities' ASCs is contained in the Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A. BPA's assumptions regarding the source and cost of in-lieu resources were as follows. BPA assumed that in-lieu resources could be acquired by market purchases. *Id.* The cost of such purchases is appropriately reflected by BPA's forecast of five-year flat-block purchases, adjusted to reflect shaped delivery. *Id.* *See* Oliver *et al.,* WP-02-E-BPA-20. Shaped delivery is based on PF-02 billing determinants. Boling and Doubleday, WP-02-E-BPA-30, at 11. Average energy prices from this forecast are 29.0 mills/kWh. *Id.* Since this market forecast is for undelivered energy, BPA assumed 3.40 mills/kWh for delivery based on the forecast of the transmission contribution to the PF Exchange Program rate. *Id.* *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 77.

Because in-lieu transactions are governed by the terms of the RPSAs, BPA had to make assumptions regarding the relevant provisions of the RPSAs during the rate period. Boling and Doubleday, WP-02-E-BPA-30, at 12. BPA has not yet negotiated new RPSAs for the period beginning in FY 2002. *Id.* BPA assumed that contract provisions for new RPSAs would not unduly limit BPA's statutory right to implement in-lieu transactions. *Id.* For example, the previous RPSAs included seven-year notice provisions for implementing in-lieu transactions based on the time needed to construct a new generating resource. *Id.* Given the changes in the utility industry since 1981 and the ability of utilities to acquire power much more quickly, BPA assumed that the notice period to begin an in-lieu transaction would be short enough to allow in-lieu transactions to begin in FY 2002 after the negotiation of new RPSAs. *Id.*

In order to determine which exchanging utilities would be subject to in-lieu transactions, BPA developed forecasted ASCs for the exchanging utilities. *Id.* BPA then compared the ASCs with a proxy for the new PF Exchange rate, which was determined to be at least as high as the

1996 PF Exchange rate. *Id.* BPA then compared the simple average of utilities' forecasted new ASCs over the rate period to the 1996 PF Exchange rate (32.7 mills/kWh), and determined that only four exchanging utilities were likely candidates for in-lieu transactions: MPC, PSE, PGE, and PacifiCorp's Utah Power Division. *Id.* MPC's ASC is forecasted to be 33.12 mills/kWh in 2002, increasing to 41.13 mills in 2010. *Id.* PSE's ASC is forecasted to be 39.01 mills/kWh in 2002, increasing to 47.01 mills in 2010. *Id.* PGE's ASC is forecasted to be 38.68 mills/kWh in 2002, increasing to 46.04 mills in 2010. *Id.* Utah Power's ASC is forecasted to be 37.93 mills/kWh in 2002, increasing to 43.27 mills in 2010. *Id.*

BPA then conducted preliminary runs of RAM reflecting the participation of the four IOUs. *Id.* While PSE, PGE, and PacifiCorp's Utah Power Division have ASCs significantly higher than the preliminary RAM PF Exchange rate, MPC's average ASC for the rate period was 35 mills/kWh, which was relatively close to the preliminary rate. *Id.* Because of MPC's small residential load (approximately 60 aMW), and the risk of forecast error and administrative costs making the in-lieu transaction uneconomic, BPA would not in-lieu MPC. *Id.* at 12-13.

BPA assumed that in-lieu transactions will occur beginning FY 2002 for 50 percent of the exchange loads of PSE, PGE, and PacifiCorp's southern Idaho jurisdiction of its Utah Power Division. Boling and Doubleday, WP-02-E-BPA-30, at 13. This averages 1,202 aMW over the rate period. *Id.* BPA assumed that the loads of all three utilities would be subject to in-lieu in order to spread the impact of in-lieu transactions among the three state jurisdictions of Washington, Oregon, and Idaho instead of placing the impact in a single jurisdiction. *Id.*

BPA proposed to in-lieu only 50 percent of the utilities' residential loads instead of a larger amount for a number of reasons. *Id.* As described above, in-lieu transactions are appropriate only for utilities with ASCs that exceed the PF Exchange rate. *Id.* The proposed PF Exchange Program rate of 37.11 mills/kWh is reasonably close to the utilities' ASCs in the early years of the rate period. *Id.* BPA is less inclined to assume a larger in-lieu amount where there are only small differences between ASCs and the PF Exchange rate. *Id.* In addition, BPA has limited the in-lieu amount to 50 percent to account for risk and uncertainty regarding forecasted ASCs, to reduce possible adverse effects to the utilities of receiving large in-lieu power deliveries on relatively short notice, and to ensure that some amount of benefits of Federal power would be provided to the residential and small farm consumers of the exchanging utilities. *Id.*

BPA is unsure whether, over the lengthy ASC forecast period, there will continue to be a significant difference between the expected price of in-lieu power and the ASCs of likely candidates for in-lieu transactions. *Id.* at 13-14. BPA is looking ahead more than two years until the start of the rate period, five years during the rate period, and then, for purposes of the section 7(b)(2) rate test, an additional four years. *Id.* at 14. While BPA's forecasts have been conducted in the most accurate manner possible, BPA is not developing its forecasts from current ASC reports. *Id.* As noted above, due to settlement of most exchanging utilities' RPSAs, BPA does not have information that is as accurate as was previously available to BPA. *Id.* In addition, ASCs are also subject to variation for reasons beyond BPA's control, such as market forces and industry restructuring. *Id.*

In addition, PSE, PGE, and the southern Idaho jurisdiction of PacifiCorp's Utah Division could be placed in a surplus condition under an actual delivery of PF power upon relatively short notice. *Id.* That is, the sale of power to an IOU under an in-lieu transaction could provide the utility with more resources than would be necessary to meets its loads, thereby rendering the utility surplus. *Id.* Disposing of such surplus could impose costs on the utilities and their customers if the revenue received for any resulting surplus sales should prove to be less than was paid for the power purchased from BPA. *Id.* Utilities' sales of their surplus might also require marketing Northwest resources outside the region. *Id.* Based on data taken from the 1997 Pacific Northwest Loads and Resources Study (Whitebook), in-lieu sales equal to 50 percent of the utilities' exchangeable loads would approximately equal the utilities' deficits and would help minimize the effect of displacing the utilities' resources. *Id.*

BPA also considered the adverse effects of reduced Exchange benefits in determining the in-lieu amount. *Id.* Absent a settlement, implementation of the REP is the manner in which residential and small farm customers of regional IOUs receive benefits of Federal power. *Id.* In-lieu transactions, while fiscally prudent for BPA, reduce Residential Exchange benefits. *Id.* at 14-15. Assuming 100 percent in-lieu transactions, for example, would completely eliminate residential exchange benefits where in-lieu resource costs are less than the PF Exchange rate. *Id.* at 15. This would eliminate nearly all benefits of Federal power received by the residential and small farm customers of IOUs. *Id.* In addition, the current proceeding highlights certain potential effects on exchange benefits that were not previously recognized by BPA. *Id.*

The anticipated effect on residential exchange benefit payments to PGE, PSE, and Utah Power from 50 percent in-lieu transactions with those utilities would be influenced by the forecast that in-lieu resource costs will be considerably lower than the PF Exchange rate. *Id.* Given this relationship, the effect then depends on the contract provisions that are assumed to be in place during the rate period to implement in-lieu transactions. *Id.* Under the 1981 RPSA, a utility had two options if BPA intended to implement an in-lieu transaction. *Id.* The utility could purchase actual power from BPA at the PF Exchange rate in the amount of the in-lieu transaction, or it could refuse the power and reduce its ASC to the cost of the in-lieu resource for the amount of the in-lieu transaction (in this case, 50 percent). *Id.* Under current conditions, where in-lieu resources are projected to cost considerably less than the PF Exchange rate, utilities would have no rational incentive to purchase power from BPA at greater than market prices. *Id.* The utility would opt instead to reduce its ASC to the in-lieu resource cost. *Id.* By reducing its ASC to resource cost for, in BPA's proposal, 50 percent of its exchange load, the utility might continue to receive exchange benefits for the remaining 50 percent of its exchange load. *Id.* The 1981 RPSA is silent, however, regarding the effect on total benefits associated with the reduced ASC portion of exchange load. *Id.*

There are different contract options to address the treatment of that portion of exchange load that has an ASC reduced below the PF Exchange rate. *Id.* at 16. One approach would have the "negative benefits" of the in-lieued portion of exchange load be offset against the positive benefits associated with the remaining exchange load. *Id.* This approach could result in net negative benefits to a utility. *Id.* This situation could occur if the difference between the utility's ASC and PF Exchange rate (positive benefits) is less than the difference between the PF Exchange rate and the in-lieu resource cost (negative benefits). *Id.* This option could create anomalous results. *Id.* For example, a utility could be required to pay money to BPA. *Id.* Also, a 100 percent in-lieu transaction could be of less benefit to BPA than a 50 percent in-lieu transaction. *Id.*

An alternative approach would assume that a new RPSA would allow a utility to terminate its participation in the REP for the in-lieued portion of its exchange load, where such load had its ASC reduced to the in-lieu resource cost and where such cost was less than the PF Exchange rate. *Id.* This would allow a utility to receive benefits for its remaining nonin-lieued exchange load. *Id.* Based on BPA's proposal of a 50 percent in-lieu of PGE, PSE, and Utah Power, each utility's exchange benefit would be reduced by approximately one-half. *Id.* This would avoid the possibility of zero, or even negative, benefits to a utility in a situation where some of the utility's exchange load is still actively exchanging. *Id.*

The DSIs argue that due to BPA's errors in determining exchange costs, the PF Exchange rate was set so high that no IOU would engage in an in-lieu transaction. DSI Brief, WP-02-B-DS-01, at 66. They argue that BPA therefore treated the in-lieu transaction as if it did not occur and simply reduced the exchange load by 50 percent. *Id.* The DSIs' argument is based upon false assumptions. First, as evidenced by the record in this proceeding, BPA properly established the PF Exchange rate. Further, as discussed in greater detail below, it is a reasonable assumption that where the cost of in-lieu power is less than the PF Exchange rate, it would not be economic for a utility to participate in an in-lieu transaction.

The DSIs note BPA's reasons for BPA's 50 percent in-lieu assumption. DSI Brief, WP-02-B-DS-01, at 66. The DSIs argue that BPA should increase the in-lieu assumption to 100 percent of the purchase from high-ASC utilities. *Id.* The DSIs argue that if it is economical to in-lieu 50 percent of a transaction, it is economical to in-lieu the entire purchase. *Id.* BPA disagrees. As noted previously, section 5(c)(5) of the Northwest Power Act provides:

> . . . [T]he Administrator *may* acquire an equivalent amount of electric power from other sources to replace power sold to such utility as part of an exchange sale if the cost of such acquisition is less than the cost of purchasing the electric power offered by such utility.

16 U.S.C. §839c(c)(5) (emphasis added). The Northwest Power Act is clear that BPA's decision to conduct an in-lieu transaction is discretionary, not mandatory. PPC notes that there is nothing to prevent BPA from in-lieuing a portion of the utility's eligible exchange load. PPC Brief, WP-02-B-PP-01, at 74. As previously noted, there are economic and other factors that are involved in a decision to in-lieu an exchanging utility. Boling and Doubleday, WP-02-E-BPA-53, at 6; Boling and Doubleday, WP-02-E-BPA-30, at 13. Even assuming for the sake of argument, however, that economic factors were the only criteria to be used in determining an in-lieu amount, BPA would still be reluctant to in-lieu 100 percent of exchange load. Boling and Doubleday, WP-02-E-BPA-53, at 6. The Joint DSIs admit that there should be "sufficient margin" between ASCs and the PF Exchange rate "to assure that there is a likelihood that the exchange transaction will actually occur." *Id.* Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 10. BPA noted in its direct testimony that the lack of current data to forecast ASCs, uncertainty regarding market forces, and industry restructuring create risk

and uncertainty that the utilities' ASCs could be less than the PF Exchange rate. Boling and Doubleday, WP-02-E-BPA-53, at 6; Boling and Doubleday, WP-02-E-BPA-30, at 13-14. Such risk has appropriately influenced BPA's economic assessment of in-lieu transactions. Boling and Doubleday, WP-02-E-BPA-53, at 6.

In addition, BPA placed considerable emphasis on certain noneconomic factors. *Id.* In-lieu transactions are neither mandatory nor required to be based solely upon economic considerations, but are exercised in the Administrator's discretion consistent with law. *Id.* In making its determination that BPA would in-lieu 50 percent of exchanging loads, BPA considered factors such as reducing the possible adverse impact that an in-lieu transaction might impose on an exchanging utility, and ensuring that some level of Federal power benefits would be available to the residential and small farm consumers of utilities that continue the REP. *Id.* A 100 percent in-lieu assumption would disregard these factors. *Id.* As noted previously, the PPC argues that there is nothing to prevent BPA from in-lieuing a portion of the utility's eligible exchange load. PPC Brief, WP-02-B-PP-01, at 74, citing Hansen *et al.*, WP-02-E-PP-09.

The Joint DSIs also argued that, for 100 percent in-lieued exchanges, BPA should calculate its own net cost of the exchange using the in-lieued price as a substitute for the ASC of the exchanging utility and treat the load as it would otherwise. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 10. The DSIs argued that BPA should assume that the utility deems its ASC to be equal to the purchase price of the in-lieu power. *Id.* They argued that if the in-lieu price is less than the PF Exchange rate, BPA should treat the utility as a deemer, and where the in-lieu price is greater than the PF Exchange rate, BPA should include the utility's load as if it were exchanging at its full ASC. *Id.* This approach is inappropriate. Boling and Doubleday, WP-02-E-BPA-53, at 7. This treatment of load would be appropriate only for a 100 percent in-lieu transaction. *Id.* If the in-lieu cost exceeds the PF Exchange rate, the utility's exchangeable load would continue to receive monetary benefits. *Id.* However, if the in-lieu cost is less than the PF Exchange rate, the utility's exchangeable load would build a deemer balance, which would not (under a new exchange contract containing similar deemer account provisions) be a cash obligation to the utility and its consumers. *Id.* As discussed in BPA's direct testimony, an in-lieu for less than 100 percent could lead to anomalous and undesirable results unless the utility is allowed to terminate any in-lieued load when the in-lieu cost is less than the PF Exchange rate. *Id.*; Boling and Doubleday, WP-02-E-BPA-30, at 15-16. As discussed earlier, a decision by the Administrator to in-lieu 50 percent of a utility's exchange load might be based in part on spreading some level of Federal power benefits to exchanging utilities. Boling and Doubleday, WP-02-E-BPA-53, at 7. Without an option to terminate its in-lieued exchange load, a utility with some actively exchanging load could find itself in the perverse situation of receiving zero, or even negative, overall benefits. *Id.*

The DSIs argue that BPA missed the import of the DSI proposal. DSI Brief, WP-02-B-DS-01, at 68. The DSIs argue that BPA's initially proposed PF Exchange rate was higher than it should have been and that ASCs were overstated. *Id.* The DSIs argue that BPA has overstated the in-lieu purchase cost with inappropriate transmission costs. *Id.* The DSIs argue that if ASCs, the PF Exchange rate, and in-lieu purchase costs had been calculated as the DSIs suggested, larger exchange benefits would have been provided to the in-lieued utilities than BPA is offering them. *Id.* The DSIs argue that BPA's conclusion that an in-lieu transaction was of no value to the utility is an artifact of errors in BPA's analysis that artificially raised the PF Exchange rate above the market price of power. *Id.* The DSIs' claims regarding BPA's proposed PF Exchange rate were based primarily on arguments relating to the section 7(b)(2) rate test. BPA agreed and disagreed with particular DSI arguments in this area; these arguments are addressed in detail in ROD chapter 12. The DSIs' claims that BPA's forecasted ASCs were overstated were addressed previously in this section. The DSIs' argument that BPA has overstated the in-lieu purchase cost with inappropriate transmission costs was addressed in part in this section, and another variation of the DSIs' argument will be addressed in Issue 4, *infra*. While the DSIs argue that BPA's conclusion that an in-lieu transaction was of no value to the utility is an artifact of errors in BPA's analysis that artificially raised the PF Exchange rate above the market price of power, BPA, as discussed in greater detail elsewhere in this section of the ROD, believes that its analyses and conclusions were correct. With the PF Exchange rate properly determined to be above the market price of power, BPA has correctly concluded that exchanging utilities would have no rational incentive to purchase in-lieu power from BPA at a rate greater than market prices. Boling and Doubleday, WP-02-E-BPA-30, at 15.

The DSIs argue that the purpose of the in-lieu provision of section 5(c) of the Northwest Power Act is to limit the cost of the REP. DSI Ex. Brief, WP-02-R-DS-01, at 23-24. The DSIs argue that because BPA is required to recover its total costs, limiting the cost of the REP is for the benefit of BPA's non-exchanging customers. *Id*. The DSIs argue that it is therefore inappropriate for BPA to determine the amount of in-lieu transactions based on the goal of providing exchanging utilities additional, non-statutory benefits at the expense of non-exchanging customers. *Id*. While the purpose of the in-lieu provision is to control REP costs, this does not mean that BPA is required to use in-lieu transaction to reduce REP costs as much as possible. As the Northwest Power Act recognizes, "the Administrator *may* acquire an equivalent amount of electric power from other sources . . . ." 16 U.S.C. §839c(c)(5). BPA is therefore not required to conduct in-lieu transactions to the fullest extent possible. Boling and Doubleday, WP-02-E-BPA-30, at 10. While conducting extensive in-lieu transactions would benefit non-exchanging customers, it would severely harm the residential and small farm consumers of exchanging utilities, for whom the REP is their primary form of access to the benefits of the Federal power system. BPA has no "goal of providing exchanging utilities additional *non-statutory* benefits" at the expense of others. Failure to in-lieu the entire load of an exchanging utility simply allows exchanging utilities to receive exchange benefits as provided in the Northwest Power Act, consistent with BPA's proposed in-lieu transactions. Boling and Doubleday, WP-02-E-BPA-53, at 16. As noted in greater detail above, there are numerous reasons for limiting in-lieu transactions.

The DSIs contend that BPA erred in concluding that in-lieu transactions are appropriate only for utilities with ASCs that exceed the PF Exchange rate. DSI Ex. Brief, WP-02-R-DS-01, at 24. The DSIs note that the PF Exchange rate is the price for BPA's sale side of the exchange, and the ASCs and in-lieu price are alternative prices for the purchase side of the transaction. *Id*. The DSIs argue that an in-lieu transaction must be judged only by whether an exchanging utility's ASC exceeds the cost of the in-lieu alternative. *Id.* This argument is not persuasive. If a utility's ASC is below the PF Exchange rate, the utility is not receiving any benefits from BPA under the REP. Boling and Doubleday, WP-02-E-BPA-30, at 3. BPA is therefore not incurring costs for that utility's participation in the REP. Because of this, and for the reasons noted previously, there is no need to in-lieu the utility.

Decision

BPA properly forecasted in-lieu transactions for 50 percent of residential exchange load. BPA properly forecasted that exchanging utilities would not purchase power from BPA in an in-lieu transaction, because such purchases would be uneconomic.

Issue 4

Whether BPA properly included certain transmission costs in the forecasted cost of in-lieu purchases.

Parties' Positions

The DSIs argue that BPA improperly included certain transmission costs in the forecasted cost of in-lieu purchases. DSI Brief, WP-02-B-DS-01, at 67; DSI Ex. Brief, WP-02-R-DS-01, at 2-67.

BPA's Position

BPA has properly included transmission costs in the forecasted cost of in-lieu purchases. Boling and Doubleday, WP-02-E-BPA-53, at 2-7.

Evaluation of Positions

The DSIs argue that BPA improperly included certain transmission costs in the forecasted cost of in-lieu purchases. DSI Brief, WP-02-B-DS-01, at 67. The Joint DSIs argued that a determination to in-lieu compares an IOU's ASC to the cost of purchasing power delivered to the BPA system. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 9-10. Because the block purchase price is a price for energy delivered to BPA's system, the Joint DSIs argued that adding additional transmission costs is wrong. *Id*. BPA disagrees. BPA has the authority to conduct an in-lieu transaction if the cost of the in-lieu acquisition (*i.e.*, the combined cost of the resource and delivery of that resource to BPA's system) is less than the cost of purchasing the electric power offered by the exchanging utility at the utility's ASC. 16 U.S.C. §839c(c)(5). However, it does not follow that BPA's PBL would always exercise its discretion to conduct an in-lieu transaction in all such circumstances. Boling and Doubleday, WP-02-E-BPA-53, at 2. Such a determination would be based on consideration of the economic viability of the entire transaction, taking into account all transaction costs and other factors. *Id.* For example, in order to accomplish the power delivery to the exchanging utility required by the in-lieu transaction, the PBL might find it necessary to purchase transmission services from the TBL that would not be required in the absence of an in-lieu transaction. *Id.* If the PBL incurs such costs, they will be included in the assessment of whether to conduct an in-lieu transaction. *Id.* If such costs make the in-lieu transaction more expensive, in the aggregate, than the traditional exchange, then BPA would not exercise its ability to in-lieu. *Id.*

In summary, an in-lieu transaction is authorized and will be considered based on an initial comparison between ASC and the cost of the in-lieu resource delivered to BPA's system. *Id.* At this stage, an assessment of the economic viability of the transaction based on total transaction costs will be used to determine whether conducting the in-lieu transaction would be prudent. *Id.* at 2-3. While the DSIs are correct that the block purchase price is a price for energy delivered to BPA's system, this is not the end of the question, because the PBL must determine if there are additional costs that must be considered. *Id.* at 3.

The Joint DSIs argued that the cost to deliver the power to PBL's customer in an in-lieu transaction will be paid by the customer in transmission charges paid to the TBL. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 9. This argument is incorrect. The customer will not pay the TBL for transmission. Boling and Doubleday, WP-02-E-BPA-53, at 3. The PBL will purchase transmission, most probably from the TBL, and the PF Exchange Program rate revenues will reimburse the PBL for its transmission expenses. *Id.* The PF Exchange Program rate is a bundled rate with transmission included. *Id.*

The Joint DSIs argued that deliveries of in-lieu power do not have to be at the same point of receipt on the BPA system as deliveries of the exchange purchase, because the transmission paid by the load moves the power from the BPA system point of receipt to the utility's point of delivery. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 9. Therefore, the additional transmission adder is not needed for the in-lieu purchase. *Id.* BPA agrees that deliveries of in-lieu power to BPA do not have to be at the same point of receipt on the BPA system as deliveries of the exchange purchase. Boling and Doubleday, WP-02-E-BPA-53, at 3. As discussed above, however, BPA power must be delivered to a utility's point or points of delivery in an in-lieu transaction. *Id.* Regarding the "additional transmission adder," the Joint DSIs apparently believe that the utility pays the transmission provider for the transmission from BPA's system to the utility's point of delivery, so transmission costs should not be included in the in-lieu resource cost determination. *Id.* However, the load does not pay directly for transmission. *Id.* In the case of an in-lieu transaction, the PF Exchange Program rate paid by the exchanging utility includes transmission costs. *Id.* This transmission portion of the PF Exchange Program rate reimburses the PBL for the costs of transmission it pays to the transmission provider. *Id.* The load pays for transmission through the PF Exchange Program rate, but these revenues go to the PBL. *Id.* at 3-4. From the PBL's point of view, in-lieu related transmission of BPA power is both a cost, which it pays to the TBL, and a revenue, which it recovers by way of the PF Exchange Program rate. *Id.* at 4.

The Joint DSIs argued that the transmission costs for in-lieu power are already properly recognized as a part of the PF Exchange rate. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 9. The Joint DSIs stated that on the purchase side, BPA costs power where it comes to the system, and on the sale side, BPA adds transmission costs to get the power across the system to the delivery point. *Id.* The Joint DSIs argued that for BPA to add transmission to the in-lieu purchase price is double-counting the transmission charges, because the transmission is already charged on the sales side. *Id*. This argument is incorrect. When determining whether an in-lieu transaction is financially prudent, the PBL must consider the total cost of the in-lieu transaction it will face. Boling and Doubleday, WP-02-E-BPA-53, at 4. Where an in-lieu purchase is delivered to BPA's system, such total in-lieu transaction costs include the cost of acquiring the in-lieu resource, the cost of transmission to get the power to BPA's system, and the cost to wheel BPA power to the utility's point of delivery. *Id.* Only if the PBL's total costs of the in-lieu transaction, including all transmission costs, are less than the exchange transaction costs (*i.e.*, the utility's ASC) would the in-lieu transaction be financially prudent. *Id.* On the in-lieu transaction revenue side, the customer is charged the PF Exchange Program rate, which includes a transmission charge. *Id.* This is not double-counting the transmission costs. *Id.* From the PBL's point of view, the in-lieu transaction has a cost of transmission component and an offsetting transmission revenue component. *Id.* These two transmission components are not added together, they cancel each other out. *Id.* Therefore, there is no double-counting. *Id.*

The Joint DSIs argued that BPA should use the in-lieu purchase price without transmission costs to compare with the utility's ASC when determining if an in-lieu transaction is indicated. Schoenbeck *et al.,* WP-02-E-DS/AL/VN-04(E1), at 10. As discussed above, however, in-lieu transaction costs must include any costs of wheeling BPA power to the point or points of delivery. Boling and Doubleday, WP-02-E-BPA-53, at 5. The PBL must consider the full cost of the in-lieu transaction, not just the cost of getting in-lieu power to BPA's system. *Id.* If the Joint DSIs' recommendation were followed, the PBL could enter into an in-lieu transaction that would be more costly than the associated exchange transaction. *Id.* For example, consider a situation where a utility's ASC is $39/MWh, the PF Exchange Program rate is $37/MWh, the cost of the in-lieu resource delivered to BPA's system is $36/MWh, and TBL transmission from BPA's system to the utility's point of delivery is $4/MWh. *Id.* Traditional exchange benefits, a net cost to the PBL, would be $2/MWh ($39 minus $37), with the utility's ASC representing a fixed total transaction cost. *Id.* Using the Joint DSI method, the PBL would compare the cost of the in-lieu resource delivered to BPA's system of $36/MWh with the utility's ASC of $39/MWh and determine that the in-lieu transaction should occur. *Id.* However, this method fails to account for the additional costs associated with the in-lieu transaction. *Id.* These costs include the $4/MWh associated with the PBL's purchase of TBL transmission from BPA's system to the utility's point of delivery. *Id.* This additional cost is made necessary by the fact that an in-lieu transaction, unlike the traditional exchange transaction, requires that BPA actually deliver power to the exchanging utility's point of delivery. *Id.* For this reason, the correct method is to compare the $40/MWh ($36 plus $4) total in-lieu transaction cost with the utility's ASC of $39/MWh. *Id.* In this situation, an in-lieu transaction would cost the PBL a total transaction cost of $3/MWh ($40 minus $37), $1/MWh more than the $2/MWh traditional exchange payment calculated above. *Id.*

The DSIs argue that BPA improperly added an extra transmission cost to the in-lieu transaction. DSI Brief, WP-02-B-DS-01, at 67. BPA disagrees. In rebuttal testimony, BPA established that the total in-lieu transaction cost, the total cost the PBL must consider when determining if an in-lieu transaction is financially prudent, includes two types of transmission costs. Boling and Doubleday, WP-02-E-BPA-53, at 2-5. Where an in-lieu purchase is delivered to BPA's system, such total in-lieu transaction costs include the cost of acquiring the in-lieu resource, the cost of transmission to get the power to BPA's system, and the transmission cost to wheel BPA power to the utility's point of delivery. *Id.*

The DSIs note BPA's claim that there is an "extra transmission cost" to the PBL in an in-lieu transaction, because the PBL would have to make actual transmission payments to the TBL for wheeling power sold to a utility in an in-lieu transaction. DSI Brief, WP-02-B-DS-01, at 67. BPA disagrees with the DSIs' characterization that the cost of wheeling BPA's system power to the utility's point of delivery during an in-lieu sale is an "extra transmission cost." The Joint DSIs first showed their misunderstanding of the in-lieu power sale process in their direct testimony, where they stated that "[t]he cost to deliver the power to BPA's customers will be paid by the customers in transmission charges paid to the TBL." Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E-1), at 9. The Joint DSIs went on to accuse BPA of double-counting the transmission charges on the power side, because the transmission is already charged on the sales side. *Id.* at 10. The Joint DSIs apparently believe that the utility pays the transmission provider for the transmission from BPA's system to the utility's point of delivery, so transmission costs should not be included in the in-lieu resource cost determination. Boling and Doubleday, WP-02-E-BPA-53, at 3-4. However, the load does not pay directly for transmission. *Id.* In the case of an in-lieu transaction, the PF Exchange Program rate paid by the exchanging utility includes transmission costs. *Id.* This transmission portion of the PF Exchange Program rate reimburses the PBL for the costs of transmission it pays to the transmission provider. *Id.* The load pays for transmission through the PF Exchange Program rate, but these revenues go to the PBL. *Id.* From the PBL's point of view, in-lieu related transmission of BPA power is both a cost, which it pays to the TBL, and a revenue, which it recovers by way of the PF Exchange Program rate. *Id.*

The DSIs argue that Northwest Power Act sections 5(c) and 7(b) require that, for ratesetting purposes, BPA must treat the REP as if it were a purchase and sale of power, yet BPA modeled the Residential Exchange different than a purchase and sale. DSI Brief, WP-02-B-DS-01, at 67. BPA disagrees. For ratemaking purposes, BPA's rates models treat the REP as if it were a purchase and sale of power. The purchase of power under the REP is represented by the gross costs of the purchased Residential Exchange resources shown in the RAM Cost of Service Analysis (COSA) tables. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 49-53, line 18. The allocation of the purchased power from the residential exchange resources to customer class loads is shown in the EAF tables. *Id.* at 47-48. The sale of power under the REP is shown in Table RDS36 in the RAM. *Id.* at 77. BPA has always modeled the REP as a purchase and sale of power, and is doing so in this rate case. After the rates models determine the level of the PF Exchange Program rate, that rate is used in the implementation of the REP to determine the actual exchange benefits.

The DSIs argue that for a real exchange (*i.e.*, purchase and sale), BPA staff treated the cost of wheeling power sold to the exchange customer as a real cost for which the PBL would have to pay the TBL. DSI Brief, WP-02-B-DS-01, at 67. Tr. 1672-73. The DSIs argue that for the Residential Exchange, on the other hand, BPA staff modeled the sale half of the transaction as if the PBL keeps that portion of the PF Exchange rate associated with the cost of wheeling power to the exchanging utility. DSI Brief, WP-02-B-DS-01, at 67. Tr. 1673-74. The DSIs imply that this treatment of the cost of wheeling power is inconsistent with BPA staff's understanding that the residential exchange was treated as an actual exchange of power. First, BPA disagrees with the DSIs use of the term "real exchange." Outside of the ratemaking process and absent an in-lieu sale of real power to an exchanging utility, the implementation of the REP does not comprise a "real" sale of power to the exchange customers. Boling and Doubleday, WP-02-E-BPA-30, at 2. A "real" sale of BPA system power to the IOUs could take the form of an in-lieu sale or a sale under the NR or FPS rate schedules. But in none of these cases would there be a balancing "exchange purchase" from the IOUs. Also, the DSIs have misrepresented BPA's cross-examination testimony. Tr. 1672-72. BPA's witness was not discussing a "real exchange," as the DSIs contend. The transcript quoted below shows clearly that BPA's witness was originally answering questions concerning a hypothetical sale of real BPA system power and was careful to identify the point at which the DSI attorney started discussing an exchange transaction with an exchange customer.

> Q. In an actual power sale where you agree through your contract to provide delivery to a utility's system, you would incur the generation costs we just talked about and some transmission expenses, am I correct?
>
> A. (Mr. Doubleday) Yes.
>
> Q. And those transmission expenses would be a real expense you would have to pay money to the TBL, am I correct?
>
> A. (Mr. Doubleday) Yes. The PBL would have--the PBL would have an expense due to services provided by the TBL.
>
> Q. So the net to the PBL, exclusive of the pass-through of the transmission expenses to the TBL, would be the cost of generation, am I correct?
>
> A. (Mr. Doubleday) It would be--yes, as represented by the undelivered rate, I guess.
>
> Q. And when you model the sales side, the BPA sales side, of the exchange transaction, do you model a transmission expense in which you turn the proceeds from the transmission component of the sale over to the TBL?
>
> A. (Mr. Doubleday) Just to be clear, this is modeling the exchange once again?
>
> Q. Yes.
>
> A. (Mr Doubleday) We are away from the true and actual sale?
>
> Q. Right.
>
> A. (Mr Doubleday) No, we do not--we do not assume that monies will be sent to the TBL.

Tr. 1672-73. In cross-examination, BPA's witness was careful to distinguish between an actual sale of BPA system power and the traditional REP. In the actual sale of power, the TBL would provide a service and receive revenues. Tr. 1672-74. In the implementation of the traditional REP, the TBL does not provide a service and does not receive revenues. *Id.*

The DSIs argue that this treatment of the cost of wheeling power to the exchanging utility is contrary to BPA staff's understanding that the residential exchange was supposed to be treated as an actual exchange of power. DSI Brief, WP-02-B-DS-01, at 67. Tr. 1667. The DSIs have misrepresented BPA's cross-examination testimony. The BPA witness testified that for ratemaking purposes, BPA models the REP as an actual exchange of power. Tr. 1667. The DSIs are confusing the treatment of transmission costs and revenues under three separate situations: an actual sale of BPA system power, the actual implementation of the REP, and REP ratemaking and modeling assumptions. In an actual sale of BPA system power, the TBL would provide wheeling services and would receive revenues. Tr. 1672. As stated above, for ratemaking purposes, which include the determination of the level of the PF Exchange Program rate, the REP is modeled as an actual purchase and sale, complete with wheeling costs. However, under the normal implementation of the REP, which uses the PF Exchange Program rate calculated in the rates models to determine exchange benefits, no actual power is transferred either to or from BPA. The "exchange" has been referred to as a "paper" transaction, where BPA provides the participating utility cash payments that represent the difference between the power "purchased" by BPA at the utility's ASC and the less expensive power "sold" to the participating utility at BPA's PF Exchange Program rate. Boling and Doubleday, WP-02-E-BPA-30, at 2. The utility's ASC and BPA's PF Exchange Program rate are assumed to have similar components, including generation costs and wheeling costs, so as to make their comparison viable. Tr. 1667. The TBL would not receive revenues under the normal implementation of the REP, because the PBL is responsible for all costs and would, therefore, receive all revenues. Tr. 1674-75.

The DSIs argue that BPA's demonstration of its claim that it does not model the REP inconsistent with an actual purchase and sale is nothing more than a description of its inconsistencies. DSI Ex. Brief, WP-02-R-DS-01, at 24, citing Draft ROD, WP-02-A-01, at 11-19 to 11-20. BPA disagrees with the DSI argument that BPA has modeled the REP different than a purchase and sale. As discussed above, for ratemaking purposes, BPA's rates models treat the REP as if it were a purchase and sale of power. The *purchase of power under the REP* is modeled by the gross costs of the purchased Residential Exchange resources shown in the RAM COSA tables. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 49-53, line 18. The allocation of the purchased power from the Residential Exchange resources to serve customer class loads is shown in the EAF tables. *Id.* at 47-48. The Rate Design Step of the RAM allocates the costs associated with the purchase of the REP resources in the COSA_11 table. *Id.* at 56. The *sale of power under the REP* is modeled in Table RDS36 in the RAM. *Id.* at 77. BPA has always modeled the REP as a purchase and sale of power, and is doing so in this rate case. After the rates models determine the level of the PF Exchange Program rate, that rate is used in the implementation of the REP to determine the actual exchange benefits.

The DSIs argue that BPA admits that it models the REP as if the PBL retains the revenues from the sale of TBL transmission services, in contrast to paying those revenues over to the TBL as would occur in a actual power sale transaction. DSI Ex. Brief, WP-02-R-DS-01, at 24, citing Draft ROD, WP-02-A-01, at 11-19 to 11-20. The DSIs have misrepresented BPA's position. Nowhere in the cited material does BPA say that the REP is modeled as if the PBL retains the revenues from the sale of TBL transmission services in contrast to paying those revenues over to the TBL as would occur in a actual power sale transaction. The ratemaking modeling of the REP assumes a real power sale and assumes that the TBL will provide a service for which it would get revenues. However, no real revenues are actually distributed to the TBL under the traditional implementation of the REP. Tr. 1667. Under the actual "paper transaction" implementation of the REP, no real power is sold, and the TBL provides no service for which it would get revenues. Once again, the DSIs are confusing the treatment of transmission costs and revenues under three separate situations: an actual sale of BPA system power, the actual implementation of the REP, and REP ratemaking and modeling assumptions. In an actual sale of BPA system power, the TBL would provide wheeling services and would receive revenues. Tr. 1672. As stated above, for ratemaking purposes, which include the determination of the level of the PF Exchange Program rate, the REP is modeled as an actual purchase and sale, complete with wheeling costs. However, under the normal implementation of the REP, which uses the PF Exchange Program rate calculated in the rates models to determine exchange benefits, no actual power is transferred either to or from BPA. The "exchange" has been referred to as a "paper" transaction, where BPA provides the participating utility cash payments that represent the difference between the power "purchased" by BPA at the utility's ASC and the less expensive power "sold" to the participating utility at BPA's PF Exchange Program rate. Boling and Doubleday, WP-02-E-BPA-30, at 2. The utility's ASC and BPA's PF Exchange Program rate are assumed to have similar components, including generation costs and wheeling costs, so as to make their comparison viable. Tr. 1667. The TBL would not receive revenues under the normal implementation of the REP, because the PBL is responsible for all costs and would, therefore, receive all revenues. Tr. 1674-75.

The DSIs argue that there is no basis for claiming that under the statutory exchange "the PBL is responsible for all costs." DSI Ex. Brief, WP-02-R-DS-01, at 24, citing Draft ROD, WP-02-A-01, at 11-19 to 11-20. In summary, the DSIs argue that BPA has modeled the REP different than a purchase and sale. *Id*. at 24-25. As discussed above, under the normal "paper transaction" implementation of the REP, no real power is sold, and the TBL provides no service for which it would receive revenues. The cash payments associated with the traditional implementation of the REP are a power cost to be recovered from PBL's rates. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 99, line 24. As discussed and documented at length above, the ratemaking modeling of the Rate Design Step of the RAM clearly models the REP as a purchase of resources capable of serving load and a sale of power at the PF Exchange Program rate.

The DSIs argue that this alleged modeling inconsistency exaggerates the apparent cost of in-lieu transactions and distorts the choice to in-lieu or not in-lieu. DSI Brief, WP-02-B-DS-01, at 67. BPA has shown, as demonstrated by the foregoing discussion that, contrary to the DSIs' contention, there are no modeling inconsistencies.

Decision

BPA properly included transmission costs in the forecasted cost of in-lieu purchases.

Issue 5

Whether BPA properly developed the 1984 ASC Methodology and whether BPA should revise exchanging utilities' deemer balances.

Parties' Positions

The IOUs argue that BPA should overhaul the ASC Methodology and utilities' deemer balances to restore congressionally intended outcomes for residential consumers. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 47-48; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 37-38. PPC argues that the 1984 ASC Methodology was properly developed and has withstood the test of time. PPC Brief, WP-02-B-PP-01, at 67-68.

BPA's Position

BPA properly developed the 1984 ASC Methodology. Issues regarding deemer balances are not determined in a section 7(i) hearing. Boling and Doubleday, WP-02-E-BPA-53, at 15. Deemer balances are contract issues that must be addressed by BPA and exchanging utilities in implementing the RPSAs. *Id.*

Evaluation of Positions

The IOUs argue that BPA has not fairly administered the REP to produce an equitable result for the residential customers of regional IOUs. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 47; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 37. The IOUs note that BPA revised the ASC Methodology in 1984 to remove income taxes and return on equity from the calculation, resulting in a reduction in the amount of benefits under the REP. *Id.* Contrary to the IOUs' claims, BPA properly revised the ASC Methodology in 1984, both procedurally and substantively. The 1984 ASC Methodology was reviewed and approved by FERC. *See* Order No. 400, "Final Rule," 49 Fed. Reg. 39,293 (1984) and Order No. 400-A, 50 Fed. Reg. 4,970 (1985). The 1984 ASC Methodology was also affirmed by the United States Court of Appeals for the Ninth Circuit. *PacifiCorp v. FERC*, 795 F 2d 816 (9th Cir. 1986). The IOUs argue that while the 1984 ASC Methodology was upheld by the United States Court of Appeals for the Ninth Circuit, the court did not sanction the permanent implementation of the revised methodology. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 48. The court, however, also noted that the Northwest Power Act did not proscribe BPA's adjustments to the ASC Methodology. *See PacifiCorp*, 795 F.2d at 823. Furthermore, BPA has not stated that the current ASC Methodology is permanent. As noted below, BPA recognizes that the ASC methodology can be revised. The timing and substance of such a revision, however, are not determined in a section 7(i) proceeding to establish BPA's wholesale power rates. The IOUs also argue that there is no longer a need or justification for the exclusion of taxes and return on equity from current ASC calculations. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 48. Again, these are substantive ASC Methodology issues that can be addressed only in a separate proceeding to develop a new ASC Methodology. 16 U.S.C. §839c(c)(7). These issues cannot be resolved in a ratemaking proceeding under section 7(i) of the Northwest Power Act. 16 U.S.C. §839e(i).

The IOUs argue that BPA has recognized that the ASC Methodology can be revised. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 47. The IOUs also argue that BPA has recognized that if the ASC Methodology is revised, forecasted exchange benefits would increase significantly. *Id.* This argument mischaracterizes BPA's testimony. BPA noted that if the ASC Methodology were revised *in the manner in which the IOUs would like to revise it*, exchange benefits would increase. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 37. *See* Boling and Doubleday, WP-02-E-BPA-30, at 3-4. BPA did not state that any revision to the ASC Methodology would increase exchange benefits. *Id.* The effects of a change in the ASC Methodology cannot be known until a new methodology is established. A revised ASC Methodology could either increase or decrease exchange benefits.

The IOUs argue that BPA should, in a separate proceeding, revise the ASC Methodology and adjust deemer balances to reflect that corrected methodology. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 47; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 3, 13, 37-38. The ASC Methodology is not established in a section 7(i) hearing but instead, as the IOUs correctly acknowledge, in a separate administrative proceeding. 16 U.S.C. §839c(7); Boling and Doubleday, WP-02-E-BPA-53, at 15. Any decision by BPA to revise the ASC Methodology will be made in a separate forum. Boling and Doubleday, WP-02-E-BPA-53, at 15.

The IOUs also argue that it is within BPA's discretion to adjust deemer balances that have the effect of eliminating the exchange for many customers. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 47; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 38. The IOUs argue that the 1984 ASC Methodology not only reduced exchange benefits but had a significant impact on deemer accounts of some utilities. *Id.* at 48. The IOUs argue that currently calculated deemer balances are not the result of comparing a utility's ASC under the 1981 RPSA with BPA's PF Exchange rate, but are a result of comparing a utility's ASC under the 1984 ASC Methodology with BPA's PF Exchange rate. *Id.* The IOUs argue that the deemer balance should therefore not be carried over to new RPSAs. *Id.* However, ASC benefits and deemer balances are calculated by comparing a utility's ASC as established under the then-current ASC Methodology and the then-current PF Exchange rate. As noted above, BPA's 1984 ASC Methodology was approved by FERC and the Ninth Circuit. ASCs and deemer balances would thus be properly based on the comparison between a utility's ASC under the 1984 ASC Methodology and the then-current PF Exchange rate.

The IOUs argue that when utilities agreed in 1981 that deemer balances would be carried over to the next contract, they did not contemplate that BPA would make a unilateral change in the ASC Methodology and would permanently eliminate benefits. *Id.* This argument contains a number of mischaracterizations. First, the 1981 ASC Methodology, an exhibit to the RPSA, expressly provided that it could be revised. Parties therefore could easily envision that the 1981 Methodology might be revised at a later time. Also, BPA did not simply make a unilateral change in the 1981 ASC Methodology. BPA revised the ASC Methodology only after conducting an extensive administrative proceeding with regional parties as required by law. 16 U.S.C. §839c(c)(7). Furthermore, the 1984 ASC Methodology, like any ASC Methodology, does not permanently eliminate or increase exchange benefits. Because the ASC Methodology can be revised, benefits under a new methodology might be increased or decreased. The IOUs disagree with BPA's assertion that the IOUs mischaracterized BPA's change in the ASC Methodology as being "unilateral." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 38. The IOUs state that BPA cannot address the customers' intent. *Id.* BPA, however, makes no attempt to evaluate the IOU customers' intent. The development of the methodology speaks for itself. BPA's 1984 ASC Methodology ROD, BPA File No. ASC-83, recounts the process used to develop a new ASC Methodology. The ROD lists the initiation of the consultation process by publishing a "Request for Recommendations" in the Federal Register, 48 Fed. Reg. 45,829 (1983). After reviewing comments received in response to the notice, BPA published a "Proposed Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange." 49 Fed. Reg. 4,230 (1984). This proposal solicited both comments and reply comments from interested parties. *Id*. Extensive written comments were filed by interested parties. By letter dated February 17, 1984, BPA announced that public meetings would be held in Spokane and Seattle, Washington; Portland, Oregon; and Idaho Falls, Idaho, to clarify technical aspects of the proposed methodology. *Id*. On March 2, 1984, BPA announced by letter that it would be holding a transcribed public meeting on April 20, 1984, to discuss all issues relating to the BPA proposal, initial comments, reply comments, and possible settlement of any issue. *Id*. The letter also noted that additional meetings would be scheduled with the Regional Council and state regulatory commissions and that BPA would consider requests for meetings with smaller groups of parties. *Id*. Additional public meetings were held between April 23 and 27, 1984. *Id*. Additional transcribed negotiating sessions were held between April 30 and May 4, 1984. *Id*. On April 30, 1984, BPA heard extensive oral argument by all interested parties. *Id*. On May 15, 1984, after reviewing the voluminous record, BPA staff released a proposed ASC Methodology. *Id*. Additional comments were taken on the proposed methodology. *Id*. BPA issued the final ASC Methodology on June 4, 1984. In summary, one can hardly characterize the development of the ASC Methodology as a unilateral decision. Furthermore, as discussed above, it is readily apparent that the ASC Methodology can be changed and, if changed, can affect exchange benefits. Finally, with regard to deemer balances, such issues are not determined in a section 7(i) hearing. Boling and Doubleday, WP-02-E-BPA-53, at 15. Deemer balances are contract issues that must be addressed by BPA and exchanging utilities in implementing the RPSAs. *Id.*

The IOUs state that BPA has offered no reasoning in the Draft ROD as to why changing the ASC Methodology and adjusting deemer balances could not be made *concurrently* with the rate proceeding in order to produce the level of exchange benefits supported by the IOUs. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 38. By taking this position, the IOUs are in clear agreement with BPA's position that revising the ASC Methodology must be done in a different forum, and that deemer balances are contract issues not determined in a section 7(i) hearing. BPA, however, is not required to revisit the ASC Methodology at any specific time. As is clear from references to other proceedings mentioned in the record, the period during which the rate case has been conducted has been full of BPA activities. As all parties familiar with the development of a new ASC Methodology must recognize, an ASC Methodology consultation proceeding is a tremendously demanding, time-consuming undertaking. At the same time as BPA's rate case, BPA and regional parties have been working on the development of preference customer, DSI, and IOU power sales contracts; development of RPSAs; development of the proposed Residential Exchange settlement agreements with regional IOUs; public comments on whether to increase the amount of the proposed IOU settlements by 100 aMW and the proposed allocations of settlement benefits among the IOUs; development of the Power Subscription Strategy Administrator's Supplemental ROD; and so on. It would have been an administrative nightmare from both BPA's and the parties' perspectives to conduct an ASC Methodology consultation proceeding at the same time as BPA's rate case. Furthermore, even if done concurrently, the results of the new ASC Methodology and deemer balances would not have been available in time to be used in the rate case.

Decision

BPA properly developed the 1984 ASC Methodology. Issues regarding whether the 1984 ASC Methodology should be revised and, if so, in what manner, must be addressed in a separate administrative proceeding and will not be resolved here. Similarly, issues regarding deemer balances must also be addressed in a separate forum and will not be resolved here.

12.0 COST OF SERVICE ANALYSIS AND RATE MODELING

12.1 Residential Exchange Costing Model

Issue

Whether BPA properly implemented the REP costing model.

Parties' Positions

The DSIs argue that BPA committed errors in its ASC estimates. DSI Brief, WP-02-B-DS-01, at 66; DSI Ex. Brief, WP-02-R-DS-01, at 2-66.

BPA's Position

BPA has properly implemented the REP costing model. Doubleday *et al.*, WP-02-E-BPA-44, at 2-4.

Evaluation of Positions

The Joint DSIs argued that BPA's REP costing model multiplies non-exchanging utility loads by a very small number to prevent divide by zero errors, but if BPA modified the model to add a very small number rather than multiply, the divide by zero problem would be solved and the model would treat the utilities properly as ASC and PF rates change. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 3. BPA believes it treats non-exchanging utility loads properly. Doubleday *et al.*, WP-02-E-BPA-44, at 2. However, the REP costing model has been modified as the Joint DSIs suggest. Currently, operators of the model use inspection of the data to determine which of the potential exchangers will actually be exchanging during the rate period and which will be in deemer status for the rate test period. *Id.* When the expected PF Exchange Program rate is greater than the ASC of a given utility, that utility is assumed to be in deemer status for the rate test period, and its exchangeable load is zeroed out manually. *Id.* A very small number is now added to this zeroed-out exchangeable load to avoid divide by zero problems. It should be noted that the REP costing model incorporating the DSIs' suggestion yields the same results as the model used before the change, all else being equal. *Id.*

The Joint DSIs argued that BPA's Residential Exchange model does not factor the in-lieu cost into the determination of gross and net exchange costs. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 3. BPA disagrees. The "Gross Cost" and "Net Cost" tables in the "Summary" tab of the Residential Exchange model use the in-lieu cost in the calculation of gross and net exchange costs. Doubleday *et al.*, WP-02-E-BPA-44, at 3. However, when the in-lieu cost is below the expected PF Exchange Program rate, BPA assumes that the exchanging utility will terminate the in-lieu portion of its exchangeable load. *Id. See* Boling and Doubleday, WP-02-E-BPA-30, at 15-16. In this circumstance, the in-lieu cost is multiplied by the zero load to yield a zero in-lieu contribution to the gross and net exchange costs. Doubleday *et al.*, WP-02-E-BPA-44, at 3. The forecasted cost of in-lieu resources is less than the PF Exchange

Program rate in BPA's initial proposal. *Id.* Therefore, the zero in-lieu contribution to exchange costs that the Residential Exchange model calculated for the initial proposal is correct. *Id.*

The Joint DSIs argued that to properly implement the in-lieu price into the determination of gross and net exchange costs, BPA should ratio the utility's ASC and the in-lieu cost in proportion to the amount in-lieued for the comparison to the PF Exchange rate. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 3. BPA disagrees. The Residential Exchange model separates the monetary exchange portion of a utility's exchange load from the portion subject to an in-lieu transaction. Doubleday *et al.*, WP-02-E-BPA-44, at 3. The costs associated with these two parts are then determined separately. In the "Summary" tab of the model, the monetary exchange costs and in-lieu costs are added together, resulting in load-weighted totals for both the gross and net costs. *Id.* As discussed above, there are circumstances when it is appropriate to zero out the portion of an exchanging utility's load that is subject to an in-lieu transaction. *Id.* The DSIs' proposed method would yield erroneous results where, because the in-lieu resource cost was below the PF Exchange Program rate, the load subject to an in-lieu transaction was eliminated. *Id.*

The Joint DSIs argued that BPA's model does not use a utility's deemer balance when determining whether a utility is exchanging through the rate period. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 3. BPA has made only preliminary estimates of deemer balances for three exchanging utilities. Doubleday *et al.*, WP-02-E-BPA-44, at 4. These balances have not been reviewed by the exchanging utilities. *Id.* In fact, the issue of deemer balances is currently in dispute. *Id.* The existence of deemer balances and the amount of such balances, if any, must be resolved by BPA and the utilities in the negotiation and development of subsequent RPSAs. *Id.* Deemer balances are not determined in a section 7(i) hearing. Because of the preliminary and uncertain nature of the deemer balance estimates, it would be inappropriate to reflect any deemer balances in determining eligibility of the exchanging utilities during the rate period. *Id.* In addition, the three utilities with possible deemer balances (Avista, IPC, and MPC) are not forecasted to participate in the Residential Exchange during the rate period regardless of deemer balances. *Id.*

Decision

BPA properly implemented the REP costing model.

12.2 Implementation of the Rate Analysis Models (RAM)

In order to establish rates that reflect BPA's Subscription Strategy, changes and additions were made to the RAM. Doubleday *et al.*, WP-02-E-BPA-18, at 14. Care was taken to ensure that these changes and additions comport with BPA's governing statutes. *Id.* at 14-15. The RAM calculates posted rates for the five-year rate period in a two-step process. *Id.* at 15. The first step, the Rate Design Step, uses the same ratemaking methodology used in previous rate cases. Tr. 2149. The second step, the Subscription Step, takes the results of the Rate Design Step and applies Subscription Strategy-based logic to produce rates for Subscription sales. Doubleday *et al.*, WP-02-E-BPA-18, at 16.

The Rate Design Step in the RAM follows BPA's rate directives by determining the costs associated with the three resource pools (FBS resources, REP resources, and new resources) used to serve firm load, and then allocating those costs to the rate pools (PF, IP, and NR). *Id.* at 14. This cost allocation to rate pools takes place in the COSA section of the RAM. *Id.* After the initial allocation of costs, the Northwest Power Act requires that some rate adjustments be made, such as those described in sections 7(b) and 7(c) of the Northwest Power Act. *Id.* The RAM performs these rate adjustments in its Rate Design Study section. *Id.* The Rate Design Study section of the RAM concludes with the calculation of Rate Design Step rates. *Id.*

A new spreadsheet-based model (RESEXRAM) is now used to calculate the gross cost of REP resources. *Id.* This model iterates with the RAM model twice. *Id.* In the first iteration, the gross cost of REP resources is established, and adjustments are made to the values already in the COSA tables. *Id.* An unbifurcated PF rate with PF Preference and PF Exchange loads is then calculated, and the 7(b)(2) rate test is conducted. *Id.* A second iteration between the RAM-Prog model and RESEXRAM is conducted using the 7(b)(2) trigger amount from the 7(b)(2) rate test. *Id.* This iteration determines the level of the PF Exchange Program rate and the amount of net REP costs to be recovered by non-PF Exchange Program rate pools. *Id.* at 15-16.

BPA's Subscription Strategy contains alternative ways in which BPA may sell power to its customers. *Id.* at 16. For example, the Subscription Strategy proposes to offer a settlement of the REP, comprised of power sales and monetary payments, to the region's IOUs. *Id.* BPA must establish rates for such sales. *Id.* If, however, a settlement is not reached, the IOUs would continue participation in the REP, and BPA must have a rate to apply to that Program. *Id.* That rate is the PF Exchange Program rate. *Id.* The NR-02 rate and the PF Exchange Program rate are established in the Rate Design Step of the RAM. *Id.* The NR-02 rate and the PF Exchange Program rate are discussed in greater detail in the testimony of Leathley *et al.*, WP-02-E-BPA-19.

The RAM includes a Subscription Step section to calculate posted rates for the power sales envisioned in BPA's Subscription Strategy. Doubleday *et al.*, WP-02-E-BPA-18, at 16. The Subscription Step section takes the results of the Rate Design Step and adjusts them by the added credits and costs associated with BPA's Subscription Strategy policies. *Id.* The PF Preference rate, the PF Exchange Subscription rate, the RL-02 rate, and the IP-02 rate are established in the Subscription Step. *Id.* The PF Exchange Subscription rate and the RL-02 rate are discussed in greater detail in the testimony of Leathley *et al.*, WP-02-E-BPA-19. The IP-02 rate is discussed in greater detail in the testimony of Ebberts *et al.*, WP-02-E-BPA-22, and Berwager *et al.*, WP-02-E-BPA-09.

The Subscription Strategy-related cost is the cost of the monetary benefits to the IOUs associated with the proposed settlement of the REP. Doubleday *et al.*, WP-02-E-BPA-18, at 17. The Subscription Strategy-related credit is the cost savings associated with the settlement of the REP. *Id.* The Subscription Strategy assumes that regional IOUs will choose to settle the REP through the receipt of power and monetary benefits rather than continue their participation in the Program. *Id.* Under Subscription, the IOUs would be offered the equivalent of 1,800 [1,900] aMW of benefits priced at the RL-02 or PF Exchange Subscription rate. *Id.* Given BPA's decision to increase the amount of settlement benefits from 1,800 to 1,900 aMW in its

Power Subscription Strategy Administrator's Supplemental ROD, references to the 1,800 aMW amount and 800 aMW amount shall hereafter reflect the increase in such amounts in brackets, *e.g.*, [1,900]; [900]. BPA would offer a minimum of 1,000 aMW in actual power sold at the RL-02 rate or the PF Exchange Subscription rate. *Id.* The remainder, 800 [900] aMW, would be either a power sale or a cash payment depending on which is more cost-effective for BPA. *Id.* The monetary component of the settlement would be based on the difference between: (1) BPA's rate case forecast of the cost of a five-year flat-block product; and (2) the RL-02 rate or the PF Exchange Subscription rate. *Id.* It is this cash payment that is allocated during the development of the Subscription Strategy rates. *Id.* *See* Oliver *et al.*, WP-02-E-BPA-20.

The RAM equitably allocates to the PF Preference class and the RL-02 class the cost, a cost not otherwise allocated under section 7 of the Northwest Power Act, of the cash payment associated with the 800 or 900 aMW portion of the proposed settlement. Doubleday *et al.*, WP-02-E-BPA-18, at 17-18. The effect of this allocation is to equate the two rates. *Id.* at 18. This initial allocation of costs is consistent with the Subscription Strategy's expectation that PF Preference class customers and RL-02 class customers would pay similar rates for similar products. *Id.* *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, section 2.4, tables SUBSCR 01, SUBSCR 02, SUBSCR 03, SUBSCR 04.

The Subscription Strategy Step assumes that the IOUs will not choose to continue their participation in the REP. *Id.* The rates in the Rate Design Step are set at a level sufficient to recover the net cost of the REP. *Id.* The Rate Design Step rates are the starting point for the Subscription Strategy Step rates. *Id.* 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 over-collecting the Subscription Step revenue requirement. *Id.* at 19. It is this credit that is allocated during the development of Subscription Strategy Step rates. *Id.*

The RAM equitably allocates the net cost of the REP credit, a benefit not otherwise allocated under section 7 of the Northwest Power Act, to the PF Preference class, the IP-02 class, and the RL-02 class. *Id.* This allocation takes into account the IP-PF link, as well as the DSI floor rate test. *Id.* At this point in the model, when a portion of the REP credit is allocated to the IP-02 rate so that the IP-02 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. *Id.* Therefore, the IP rate is set at the DSI Floor, and the remaining REP credit is allocated to the PF Preference and RL-02 rates, reducing them to their final Subscription Strategy Step levels. *Id.* This allocation of credits achieves the Subscription Strategy expectation that PF Preference class customers, IP-02 class customers, and RL-02 class customers would pay similar rates for similar products, while maintaining the PF-IP relationship in section 7(c) of the Northwest Power Act. *Id.* *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, section 2.4, tables SUBSCR 01, SUBSCR 02, SUBSCR 03, SUBSCR 04.

The IP rate class sales forecast in the Rate Design Step up to this point in the Subscription Strategy Step modeling has been 990 aMW. *Id.* After discussions with the DSIs, BPA decided to purchase 450 aMW specifically for the DSIs, with the understanding that the total of 1,440 aMW would 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 purchases. *Id.* at 19-20;

see Berwager *et al.*, WP-02-E-BPA-09. In BPA's initial proposal, BPA forecasted sales of 1,210 aMW at 23.5 mills/kWh and 230 aMW at 25.0 mills/kWh. Doubleday *et al.*, WP-02-E-BPA-18, at 20. Both rates include the costs of the C&R Discount. *Id.* BPA has determined that the above mix of sales and rates (1,210 aMW at 23.5 mills and 230 aMW at 25.0 mills) will recover the costs of serving the new higher DSI sales. *Id.*

Issue

Whether BPA properly implemented the Rate Design Step and the Subscription Step in the RAM.

Parties' Positions

Alcoa/Vanalco and the DSIs argue that BPA improperly implemented the Rate Design Step in the RAM by including a 1,000 aMW sale of power they characterize as an RL sale. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 94-96; DSI Brief, WP-02-B-DS-01, at 61-65; DSI Ex. Brief, WP-02-R-DS-01, at 2-63 to 2-65.

BPA's Position

BPA has properly implemented the Rate Design Step and the Subscription Step of the RAM and has properly included in the Rate Design Step a 1,000 aMW sale under the FPS-96 rate schedule to regional customers. Leathley *et al.*, WP-02-E-BPA-19, at 8-14; Doubleday *et al.*, WP-02-E-BPA-18, at 14-15; Doubleday *et al.*, WP-02-E-BPA-44, at 5-9.

Evaluation of Positions

Alcoa/Vanalco and the DSIs argue that BPA has included in the Rate Design Step a proposed sale of 1,000 aMW of firm power to IOUs under the RL rate. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 95-96; DSI Brief, WP-02-B-DS-01, at 64-65. The DSIs argue that BPA has failed to calculate appropriate rates in its Rate Design Step by, among other things, including a proposed 1,000 aMW sale at the PF-96 Exchange rate [sic] in its modeling, which represents a Subscription sale to the IOUs at the RL rate. DSI Ex. Brief, WP-02-R-DS-01, at 25. The DSIs' argument is clearly incorrect. First, BPA's proposed sale in the Rate Design Step is at the FPS-6 rate, not the PF-96 Exchange rate. More importantly, BPA's testimony expressly states that BPA did *not* include a proposed sale of 1,000 aMW of firm power to IOUs under the RL rate in the Rate Design Step. Doubleday *et al.*, WP-02-E-BPA-44, at 5. As described in Leathley *et al.*, WP-02-E-BPA-19, the Rate Design Step assumes an FPS sale of 1,000 aMW flat priced at a PF-96 equivalent rate level to be sold in the PNW. *Id.* This testimony expressly notes:

> *On the other hand, if the IOUs forego the Subscription settlement proposal, BPA would likely market the 1,000 aMW of power to other purchasers under the FPS-96 rate.* Consistent with BPA's Subscription Strategy, BPA expects that the rates for sales to the IOUs would be approximately equal to the level of the PF Preference rate. Therefore, the assumption of a FPS sale at a rate level equal

> to the PF Preference rate is a proper placeholder to reflect the possible sale of the 1,000 aMW.

Leathley *et al.*, WP-02-E-BPA-19, at 12 (emphasis added). From the inception of the rate case, BPA has clearly stated that the 1,000 aMW in the Rate Design Step is an FPS sale to regional customers, *not* a sale to IOUs at the RL rate. *Id.*

In the Rate Design Step, BPA assumes the traditional implementation of the REP. Doubleday *et al.*, WP-02-E-BPA-44, at 6. After meeting preference loads and an amount of DSI loads in the Rate Design Step, BPA may choose to serve additional regional loads. *Id.* As noted in BPA's Subscription Strategy, which contemplates the traditional REP as well as proposed settlements of that program, BPA's goals include spreading the benefits of Federal power and avoiding increases in BPA's PF Preference rate. *Id. See* Burns and Elizalde, WP-02-E-BPA-08, at 7. In the past, BPA's general business goals have also been to provide rate stability in the region while serving BPA's loads. Doubleday *et al.*, WP-02-E-BPA-44, at 6. The Subscription Strategy goals mentioned above are the latest expression of these long-held business goals. *Id.* BPA has determined that it can provide 1,000 aMW of additional power to its customers and not increase the PF Preference rate. *Id.* This is what BPA proposed to do. *Id.* Because BPA has not determined the precise manner in which it would provide this additional Federal power to its regional customers, BPA has assumed that it would make sales of power under the FPS rate schedule to meet regional loads. *Id.* BPA has assumed an FPS rate equal to the 1996 PF Preference rate as a reasonable price for such sales. *Id.* In summary, BPA's proposed sale of 1,000 aMW in the Rate Design Step is consistent with the Subscription Strategy and is also consistent with BPA's long-held business goals. *Id.*

Alcoa/Vanalco continue to mischaracterize BPA's 1,000 aMW FPS sale and argue that it is a part of a proposed REP settlement. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 95. Alcoa/Vanalco argue that in BPA's Loads and Resources Study, BPA included a sale referred to as "IOU sales post-2001." *Id.* Alcoa/Vanalco argue that under cross-examination, the Load Forecast panel admitted to this as "our proposed settlement of the Residential Exchange Program." *Id.* The DSIs note the same items and add that BPA's witness stated that the forecasted sale was "part of the package in the Subscription Strategy and that the amount of the sale reflected the policy of BPA's Subscription Strategy," citing Tr. 903-04. DSI Brief, WP-02-B-DS-01, at 63. Thus, they argue, although the Load Forecast panel identified this as the proposed RL sale pursuant to the settlement, and thus properly part of the Subscription Step, BPA included this in the Rate Design Step that preceded the Subscription Step. *Id.* Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 95. The DSIs' conclusions are mistaken. First, as noted above, from the inception of the rate case BPA clearly stated that the 1,000 aMW in the Rate Design Step is not a sale to IOUs at the RL rate. Leathley *et al.*, WP-02-E-BPA-19, at 12. This was reconfirmed in BPA's rebuttal testimony. Doubleday *et al.*, WP-02-E-BPA-44, at 5. Indeed, it is *impossible* for the 1,000 aMW in the Rate Design Step to be a settlement sale to the IOUs, because the Rate Design Step is a step in which only the REP exists, not the IOU Subscription settlements, which exist only in the Subscription Step.

With regard to the argument that the Loads and Resources Study panel referred to a 1,000 aMW sale as a sale related to the IOU Subscription settlements, there is a logical explanation for this description. In developing its initial rates, BPA knew that BPA's total costs in the Subscription Step would likely be greater than BPA's total costs in the Rate Design Step. This is demonstrated by a comparison of revenues and costs for each step. Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A. However, BPA is required to recover its total costs. 16 U.S.C. §839e(a)(1). It was therefore appropriate to use the Subscription Step as a base step that would ensure BPA's total cost recovery. Because BPA knew that it would offer 1,000 aMW of power to Northwest customers at the FPS-96 rate, consistent with its overall business goals, in the Rate Design Step, and also that the Subscription Step had a 1,000 aMW settlement sale to the IOUs, it did not matter, from the perspective of the Loads and Resources panel, how the 1,000 aMW was characterized. Regardless of what the 1,000 MW was called, BPA already knew that there would be a 1,000 aMW sale in each design step. Because, as noted above, the Subscription Step is the final step used in developing rates, the Loads and Resources panel logically referred to the terminology of the step that was used to determine BPA's final proposed rates: the Subscription Step.

Alcoa/Vanalco argue that because the sales they mischaracterize as RL sales were included in the Rate Design Step, the sales had to be accounted for in the load/resource balance. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 95. Alcoa/Vanalco argue that this is why the Load Forecast panel identified the 1,000 aMW as power purchased to sell to the IOUs at the RL rate. *Id.* Alcoa/Vanalco argue that rather than distinguishing between sales that would take place in the Rate Design Step and the Subscription Step, the Rate Design [sic] panel used the same load/resource study for both the Rate Design Step and Subscription Step. *Id.* Tr. 1133-34. Again, the DSIs have mischaracterized BPA's actions. As noted above, no RL sales were included in the Rate Design Step. The RL sale alone did not have to be accounted for in the load/resource balance; rather, the 1,000 aMW FPS sale to regional customers in the Rate Design Step had to be reflected in the load/resource balance, just as the 1,000 aMW of IOU settlement sales in the Subscription Step had to be reflected in the load/resource balance. This was not a problem, because there was a forecasted 1,000 aMW sale in both the Rate Design Step and the Subscription Step. Therefore, a 1,000 aMW sale in the load/resource balance accommodates both design steps. Because there was no need to distinguish between sales that would take place in the Rate Design Step and the Subscription Step, and because the amount was the same in both steps, the COSA panel properly used the same load/resource study for both the Rate Design Step and Subscription Step.

Alcoa/Vanalco argue that the foregoing decision resulted in a sizeable shift in resource acquisition costs from customers eligible to purchase under the PF Exchange rate and the NR rate, the only rates that are not subject to adjustment in the Subscription Step. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 96. Alcoa/Vanalco argue that BPA was buying power at 28.1 mill/kWh but proposing to sell power to the IOUs at approximately 20 mills/kWh. *Id.* Alcoa/Vanalco argue that rates calculated under the Rate Design Step were forced to allocate a revenue deficiency of approximately 8 mills/kWh, or $350 million over the rate period. *Id.* The DSIs make similar arguments and argue that this resulted in costs solely attributable to the Subscription Strategy migrating into those rates set solely in the Rate Design Step, the PF Exchange rate and the NR rate. DSI Brief, WP-02-B-DS-01, at 64; DSI Ex. Brief, WP-02-R-DS-01, at 25. The DSIs argue that including 1,000 aMW of FPS sales that they mischaracterize as sales under the RL rate is an error, as it is axiomatic that an agency cannot make contradictory findings: the 1,000 aMW will be served along with a traditional REP (in the Rate Design Step), and the 1,000 aMW will be served instead of the REP (in the Subscription Step). DSI Ex. Brief, WP-02-R-DS-01, at 25. As noted above, BPA assumed in the RAM's Rate Design Step a sale of FPS power to regional customers, not a proposed sale of power at the RL rate to the IOUs under a settlement of the REP. Leathley *et al.*, WP-02-E-BPA-19, at 12; Doubleday *et al.*, WP-02-E-BPA-44, at 7. Settlement of the REP is assumed in the RAM's Subscription Step. *Id.* The Rate Design Step assumes a traditional REP. *Id.* Also, as noted above, BPA determined that it could sell an additional 1,000 aMW to regional customers at an FPS price equivalent to PF-96 and still provide rate stability for BPA's preference customers. *Id.* In determining its load/resource balance and the associated revenue requirement, BPA does not assume that costs of individual resources will be allocated to particular individual power sales. *Id.* BPA has the authority to replace reductions in the capability of the FBS. *Id.* These reductions include the shutdown of the Trojan and Hanford nuclear plants (BPA's shares are 230 and 309 aMW, respectively); failure to complete Washington Nuclear Projects Nos. 1 and 3 (BPA's shares are 958 and 651 aMW, respectively); and hydroelectric capability losses (521 aMW). *Id.* System augmentation purchases replace some of these reductions in capability, and the costs of such augmentation purchases are melded with all other FBS resource costs before cost allocation to rate pools is performed. *Id.* The DSIs' assumption, in their calculation of a $350 million revenue deficiency, that the cost of system augmentation purchases should be allocated to specific FPS sales does not comport with BPA's established ratemaking methods. *Id*. Thus, BPA's findings are not contradictory at all. In the Rate Design Step, where the traditional implementation of the REP occurs, it is reasonable to forecast 1,000 aMW of sales to BPA's regional customers, not just the IOUs, in order to spread the benefits of the Federal system widely in the region while providing rate stability and avoiding rate increases to BPA's preference customers. BPA is not providing the IOUs both the REP and 1,000 aMW of regional sales in the Rate Design Step. These sales would be provided to regional customers generally. *Id*. Indeed, given that the IOUs would be participating in the REP, it is likely they would receive less of the 1,000 aMW of FPS-96 regional sales. This is perfectly consistent with the Subscription Step, where the REP does not exist and only settlements of the REP exist, and the 1,000 aMW of sales to the IOUs is for the purpose of settling the REP, just as proposed in BPA's Subscription Strategy. *Id*.

As stated above, BPA's policy goals include spreading the benefits of the Federal hydrosystem widely in the region and avoiding an increase in the PF Preference rate. Doubleday *et al.*, WP-02-E-BPA-44, at 9. BPA believes that making available to the region an additional 1,000 aMW priced at an FPS rate equivalent to PF-96 is one way it can accomplish these very important objectives. *Id.* *See* Burns and Elizalde, WP-02-E-BPA-08, at 7. In addition, as noted above, system augmentation purchases replace reductions in the capability of the FBS and, as such, augmentation costs are melded with all other FBS resource costs before cost allocation to rate pools is performed. Doubleday *et al.*, WP-02-E-BPA-44, at 9. Therefore, the $28.1/MWh for system augmentation cannot be linked to the cost of serving any particular individual PF, IP, or FPS sale and cannot, as the DSIs argue, be used as a price floor for FPS sales. *Id.*

Alcoa/Vanalco argue that, if their mischaracterization of BPA's FPS sales were true, then, as a result of this alleged error, the PF Exchange rate and the NR rate are unattractive to the IOUs, and the IOUs are virtually forced to take the proposed settlement. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 96. Alcoa/Vanalco argue that the implementation of RAM may result in the IOUs having to settle the REP for less than if BPA had properly implemented the Rate Design Step. *Id.* Alcoa/Vanalco argue that this is arbitrary and capricious and violates sections 5(c) and 7(b) of the Northwest Power Act. *Id.* The DSIs similarly argue that, given the level of the PF Exchange rate, the IOUs must choose BPA's proposed settlement or forego large benefits that a properly calculated REP would produce. DSI Brief, WP-02-B-DS-01, at 62. The DSIs argue that BPA cannot lawfully forecast fictitious loads to produce excessive rates in order to compel IOU acceptance of an alternative to the statutory REP, nor does BPA's obligation to recover its total system costs justify the creation of loads that distort rates and shift costs between rate classes. DSI Ex. Brief, WP-02-R-DS-01, at 26. BPA disagrees with these arguments. First, as explained repeatedly above, BPA did not make an error as suggested by the DSIs. Therefore, the PF Exchange and NR rates are properly established. Whether they are attractive to the IOUs is a judgment that the IOUs will have to make. BPA does not know which option the IOUs will select. Leathley *et al*., WP-02-E-BPA-19, at 11-12. There are many factors that have to be considered in such a selection. For example, in staying with the REP, the IOUs will be subject to in-lieu transactions. Similarly, there are other factors that must be considered in taking the settlement option. For example, the IOUs would have to continue to ensure the existence of their net requirements. Because BPA has properly developed its rates, the Rate Design Step will not result in the IOUs having to settle the REP for less than is appropriate under BPA's proposal. Because BPA's rate development is well-reasoned and supported by the record, it is consistent with applicable standards of judicial review. While Alcoa/Vanalco claim that BPA's approach violates sections 5(c) and 7(b) of the Northwest Power Act, they do not explain which particular parts of such provisions have been violated or in what way such provisions have been violated. BPA's review concludes that BPA's approach is consistent with both sections 5(c) and 7(b) of the Northwest Power Act. BPA also has not forecasted fictitious loads to produce excessive rates. BPA's loads in the Rate Design Step are loads that BPA intends to serve in the event that the IOUs continue participation in the traditional REP and forego the Residential Exchange settlements. Doubleday *et al*., WP-02-E-BPA-44, at 6-7. BPA's load assumptions in the Subscription Step reflect the loads BPA intends to serve if the IOUs adopt the proposed settlements. BPA is also not using its requirement to recover total system costs to justify the creation of loads. BPA has simply noted that in the Subscription Step, BPA incurs costs that BPA does not incur in the Rate Design Step due to the different assumptions regarding the implementation of the REP and the settlements. *See* section 3.4, Wholesale Power Rate Development Study, WP-02-E-BPA-05. As noted throughout this chapter, there are no fictitious loads, but rather the appropriate assumption of 1,000 aMW of sales to regional customers in the Rate Design Step.

The DSIs acknowledge that BPA established that BPA did not include "a proposed sale of 1,000 aMW of firm power to IOUs under the RL rate prior to the Subscription Step," and also acknowledge that BPA characterized the load as "an FPS sale of 1,000 aMW flat priced at the PF-96 rate level." DSI Brief, WP-02-B-DS-01, at 64, quoting Doubleday *et al.*, WP-02-E-BPA-44, at 5. The DSIs acknowledge that BPA established that the 1,000 aMW was the result of a policy decision to "provide 1,000 aMW of additional power to its customers and not increase the PF Preference rate" and that "because BPA has not determined the precise manner in which it would provide this additional Federal power to its regional customers, BPA has assumed that it would make sales of power under the FPS rate schedule to meet regional loads." DSI Brief, WP-02-B-DS-01, at 64, quoting Doubleday *et al.*, WP-02-E-BPA-44, at 6. The DSIs argue that this explanation was not persuasive after cross-examination. DSI Brief, WP-02-B-DS-01, at 64. The DSIs argue that the same panel that proffered these explanations admitted they simply took the data from the Loads and Resources Study, WP-02-E-BPA-01, for what it was (including the 1,000 aMW sale to the IOUs that the load forecasting panel identified as the proposed Subscription Exchange settlement, Tr. 901) and ran it through both the Rate Design and Subscription Steps. *Id.* The DSIs argue that BPA's claim that the 1,000 aMW sale in the Rate Design Step is not a sale to the IOUs at the RL rate is just semantics, and that BPA's own witnesses admitted that the 1,000 aMW sale is not a sale to unspecified customers, but "our proposed settlement of the Residential Exchange Program." DSI Ex. Brief, WP-02-R-DS-01, at 26, citing the Draft ROD, WP-02-A-01, at 12-6.

BPA disagrees that BPA's statement that it used the same overall loads and resources balance in the Rate Design and Subscription Steps invalidates BPA's position on the 1,000 aMW FPS sale in the Rate Design Step. To the contrary, since, as discussed above, the loads in the Subscription Step (absent those loads served with the 450 aMW of DSI-specific augmentation) are the same as the loads in the Rate Design Step; to use different loads and resources balances in each step would have been a modeling error. BPA's witnesses did not blindly use the data from the Loads and Resources Study; rather, they were simply stating the obvious, that since the loads were the same in both steps, separate load/resource balances did not need to be conducted for each step. They knew there was a 1,000 aMW FPS sale in the Rate Design Step and a 1,000 aMW RL sale in the Subscription Step. The fact that the data in the Loads and Resources Study, WP-02-E-BPA-01, refer only to the 1,000 aMW of settlement sales in the Subscription Step does not invalidate the wealth of BPA testimony concerning the 1,000 aMW of FPS sales in the Rate Design Step. The assumption of a 1,000 aMW FPS sale in the Rate Design Step is well-supported by BPA's testimony and policy, as discussed above, and is also a financially conservative assumption. BPA has shown that in the Subscription Step, 1,000 aMW of settlement power, over and above the power sold under the PF and IP rates, could be sold to the IOUs while still maintaining rate stability for the PF Preference customers. BPA also showed that the total revenue requirement in the Subscription Step is greater than the total revenue requirement in the Rate Design Step. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 91, lines 19 and 24. Therefore, it follows that in the Rate Design Step, with a lower revenue requirement, BPA could sell an additional 1,000 aMW of power, over and above the power sold under the PF and IP rates, and also maintain rate stability for the PF Preference customers.

The DSIs argue that it does not matter how BPA chooses to characterize the 1000 aMW sale, it cannot lawfully be included in the Rate Design Step if BPA does not expect to make the sale other than as a settlement of the REP claims. DSI Ex. Brief, WP-02-R-DS-01, at 26. This argument makes little sense. Since the inception of the rate case, BPA has identified a proposed 1,000 aMW sale to regional customers at the FPS-96 rate in the Rate Design Step in order to widely spread the benefits of Federal power among BPA's customers while continuing the traditional REP. As noted above, BPA did *not* assume a proposed sale of power at the RL rate to the IOUs under a settlement of the REP in the Rate Design Step. Leathley *et al.*, WP-02-E-BPA-19, at 12; Doubleday *et al.*, WP-02-E-BPA-44, at 7. Further, BPA indeed can lawfully include the 1,000 aMW sale in the Rate Design Step, because BPA has the authority and intent to make such sales in the Rate Design Step environment where the traditional REP continues. It must be recalled that the IOUs may forego the proposed settlements and BPA would make its actual sales as described in the Rate Design Step. In simple terms, settlement of the REP is assumed in the RAM's Subscription Step. *Id.* The Rate Design Step assumes a traditional REP. *Id.* As noted above, BPA determined that in the Rate Design Step it could sell an additional 1,000 aMW to regional customers at a price equivalent to the PF-96 rate and still provide rate stability for BPA's preference customers. *Id.* BPA expects to make the 1,000 aMW sale to regional customers in the Rate Design Step environment where IOUs forego the proposed settlements.

The DSIs argue that it must have been obvious to staff that if what the DSIs mischaracterized as a 1,000 aMW sale to the IOUs resulting from the Subscription Strategy were removed from the Rate Design Step, the PF Exchange, IP, and NR rates calculated therein would decrease, because BPA would have additional augmentation costs related to achieving load/resource balance in the Rate Design Step. DSI Brief, WP-02-B-DS-01, at 64-65. This *ad hominem* argument is speculative, and its implications are premised on a misstatement of fact. First, as explained above, BPA properly included a 1,000 aMW FPS sale to regional customers in the Rate Design Step. Because this was proper, BPA did not have to speculate about the rate effects of removing something that was properly included. Obviously, however, if one makes a large change in any design step there will likely be consequences of that change, regardless of whether it is the Rate Design Step or the Subscription Step. As noted previously, however, from the inception of the rate case BPA clearly stated that the 1,000 aMW in the Rate Design Step is not a sale to IOUs at the RL rate. Leathley *et al.*, WP-02-E-BPA-19, at 12. This was reconfirmed in BPA's rebuttal testimony. Doubleday *et al.*, WP-02-E-BPA-44, at 5. Indeed, it is impossible for the 1,000 aMW in the Rate Design Step to be a settlement sale to the IOUs, because the Rate Design Step is a step in which only the REP exists, not the IOU Subscription settlements, which exist only in the Subscription Step. Because BPA knew that it would offer 1,000 aMW of power to Northwest customers at the FPS-96 rate in the Rate Design Step and also that the Subscription Step had a 1,000 aMW settlement sale to the IOUs, it did not matter how the 1,000 aMW was characterized. Regardless of what the 1,000 MW was called, BPA already knew that there would be a 1,000 aMW sale in each design step.

The DSIs note that BPA staff suggested that the DSI proposal to remove the 1,000 aMW sale from the Rate Design Step does not comport with BPA's policy goals for this rate case and would require a different load/resource balance and a differently sized FBS in the Rate Design Step than in the Subscription Step of the RAM. DSI Brief, WP-02-B-DS-01, at 65. The DSIs argue that BPA's rate directives do not permit staff to mischaracterize loads. *Id.* The DSIs argue that staff offers no rationale why it is necessary or even desirable to maintain the same load/resource balance and FBS size between the Rate Design Step and the Subscription Step. *Id.* The DSIs argue that the two steps have distinct purposes, and there is no analytical or policy reason for maintaining the same loads and resources for the two steps. *Id.* The DSIs argue that the only purpose is to raise the level of the PF Exchange, IP, and NR rates in the Rate Design Step above their proper level. *Id.*

While the DSIs argue that the Northwest Power Act does not permit staff to mischaracterize loads, this did not occur in BPA's rate development, and staff has characterized loads correctly.

As repeatedly noted above, from the inception of the rate case BPA clearly stated that the 1,000 aMW in the Rate Design Step is a sale to regional customers at the FPS rate and not a sale to IOUs at the RL rate. Leathley *et al.*, WP-02-E-BPA-19, at 12. This was reconfirmed in BPA's rebuttal testimony. Doubleday *et al.*, WP-02-E-BPA-44, at 5. The DSIs argue that staff offers no rationale why it is necessary or even desirable to maintain the same load/resource balance and FBS size between the Rate Design Step and the Subscription Step. DSI Brief, WP-02-B-DS-01, at 65. The DSIs, however, have mischaracterized BPA's testimony. The statement made by staff regarding the load/resource balance and FBS did not have to do with the issue of whether or not 1,000 aMW should be included in the Rate Design Step. *See* Doubleday *et al.*, WP-02-E-BPA-44, at 8-9. Instead, it addressed the issue of whether the 1,000 aMW of the FPS sale in the Rate Design Step (which the DSIs incorrectly characterize as an RL sale) should be treated in the same manner as BPA treated the cost of the other 800 [900] aMW of benefits (monetary benefits) offered to the IOUs as part of the Subscription settlements. *Id.*

While the DSIs argue that staff have offered no reason for why it is necessary or desirable to maintain the same loads and resources for the two steps, the explanation of this issue, based on the actual issue addressed by staff, is clearly stated in staff's testimony. The 1,000 aMW FPS sale in the Rate Design Step is in support of BPA's commitment to broadly spread the benefits of the Federal hydro system in the region while providing rate stability. Doubleday *et al.*, WP-02-E-BPA-44, at 8. In the Rate Design Step, BPA is uncertain to whom the 1,000 aMW of FPS power will be sold. *Id.* In the Subscription Step, BPA assumes that the IOUs accept the Subscription settlement proposal and that 1,000 aMW is made available to the IOUs in power and 800 [900] aMW in monetary benefits. *Id.* *See* Leathley *et al.*, WP-02-E-BPA-19, at 12. The 1,000 aMW of power in the Rate Design Step should not be treated in the same manner as the 800 [900] aMW of monetary settlement benefits provided in the Subscription Step, because to do so would not comport with BPA's Loads and Resources Study, WP-02-E-BPA-01. Doubleday *et al.*, WP-02-E-BPA-44, at 8. The 1,000 aMW is included in the load/resource balances of both the Rate Design Step and the Subscription Step in the RAM. *Id.* In addition, BPA has assumed that the size of the FBS is the same in both the Rate Design Step and the Subscription Step in the RAM. *Id.* The 800 [900] aMW of IOU settlement benefits is assumed not to be actual power, is not included in the loads/resources balance, and does not affect the size of the FBS. *Id.* In summary, the DSI proposal does not comport with BPA's policy goals for this rate case and would require a different loads/resources balance and a differently sized FBS in the Rate Design Step than in the Subscription Step of the RAM. *Id.* at 8-9.

On the DSI issue raised above that was based on a mischaracterization of BPA's testimony and is not related to the treatment of the 800 [900] aMW of monetary settlement benefits, the DSIs argue that the two design steps have distinct purposes, and there is no analytical or policy reason for maintaining the same loads and resources for the two steps. This argument is misplaced. BPA has not stated that there is a requirement that the loads and resources must be identical in both design steps. Instead, BPA has established the load and resource elements of each step and reflected those in each step. For the reasons repeatedly stated above, the proper loads and resources are reflected in the Rate Design Step, and the proper loads and resources are reflected in the Subscription Step. Because these steps have been properly established, it would be inappropriate to adopt a proposal that would change the loads or resources of either step.

The DSIs argue that treatment of the 1,000 aMW serves two purposes. DSI Brief, WP-02-B-DS-01, at 65. First, this treatment hides a significant amount of costs of the Subscription Step by shifting them to the Rate Design Step, which makes the settlement of the REP appear less costly than it really is. *Id.* Second, the shifting of costs increases the PF Exchange rate and reduces the potential benefits that would be available to exchanging utilities, thereby forcing them to elect the proposed settlement. *Id.* The DSIs argue that BPA cannot violate the rate directives in furtherance of these purposes and should remove the 1,000 aMW from the Rate Design Step. *Id.* To the extent that the DSIs are stating that there were inappropriate "purposes" attempted to be achieved by BPA, such *ad hominem* arguments are false and unfounded. The DSIs attribute nonexistent motives to BPA. While elements in the conduct of BPA's design steps have impacts on the levels of rates, this is simply a truism. Regardless of how a particular element affects particular rates, the question is whether BPA has properly developed and conducted the elements. In this case, as repeatedly explained above, BPA has properly conducted the elements in the Rate Design Step and the Subscription Step. BPA's rate development in these areas does not violate, but rather properly implements, the rate directives of the Northwest Power Act. The 1,000 aMW FPS sale to regional customers must be retained in the Rate Design Step.

Alcoa/Vanalco argue that there is no basis in the Northwest Power Act for the Subscription Step, and the rate directives do not allow this adjustment in the development of rates. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 97. The DSIs argue that even assuming the lawfulness of the Subscription Strategy, BPA's discretion does not extend to inventing fictional loads for calculating rates pursuant to the rate directives of the Northwest Power Act to support the Strategy. DSI Ex. Brief, WP-02-R-DS-01, at 26. BPA must support the Subscription Strategy in compliance with the Northwest Power Act. *Id.* BPA's rate directives in section 7 of the Northwest Power Act provide significant direction to BPA in the development of rates. 16 U.S.C. §839e. The rate directives, however, are not so detailed as to cover every circumstance that arises in ratemaking. There a number of examples of steps BPA takes in the development of rates that are not expressly stated in the rate directives. For example, in ratemaking, BPA functionalizes costs between generation and transmission. In ratemaking, BPA classifies generation costs between energy, demand, and load variance. In ratemaking, BPA uses the MCA results to distribute energy costs between monthly diurnal periods. The Northwest Power Act does not explicitly require the functionalization and classification of costs, nor does it explicitly require the use of marginal cost pricing. Thus, the fact that a particular step might not be expressly mentioned in the rate directives does not mean that it is not permitted by the Northwest Power Act. In addition, when the statute does not provide BPA with express direction regarding a particular issue, it is the agency's responsibility to interpret the statute. In the current rate case, BPA is faced with a number of circumstances that it has not previously encountered. For example, as noted above, under BPA's Subscription Strategy, an IOU may choose to continue with traditional participation in the REP, or it may choose to participate in a proposed settlement of that program. BPA does not know which option will be chosen by the IOUs. BPA therefore must develop rates that can accommodate either circumstance. This is a very difficult problem to address in ratemaking, yet it must be addressed. The Northwest Power Act recognizes the need for broad discretion in the development of rate design. Section 7(e) of the Northwest Power Act provides:

> Nothing in this Northwest Power Act prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms.

16 U.S.C. §839e(e).

As noted in greater detail above, BPA has not invented fictional loads for calculating rates pursuant to the rate directives of the Northwest Power Act to support BPA's Subscription Strategy. The loads BPA has forecasted in the Rate Design Step are the loads that BPA will serve if the traditional REP continues and the IOUs do not agree to the proposed REP settlements. BPA's proposals comply with the Northwest Power Act and also support BPA's Subscription Strategy. *Id.* In summary, the manner in which BPA has developed rates in this proceeding is premised on the reasonable construction and implementation of the rate directives of the Northwest Power Act. Reflecting a Subscription Step in BPA's rates to accommodate the special circumstances faced in this case is consistent with the Northwest Power Act.

Decision

BPA properly implemented the Rate Design Step and the Subscription Step in the RAM.

12.3 Development of the Residential Load (RL) Rate and Federal Base System (FBS) Replacements

Issue

Whether BPA properly developed the RL rate and whether BPA should acquire approximately 1,282 aMW as FBS replacement resources.

Parties' Positions

WPAG argues that the RL rate must be established under section 7(f) of the Northwest Power Act, which requires that power acquired to serve the IOUs' loads must be allocated to the rates under which they take service. WPAG Brief, WP-02-B-WA-01, at 2. WPAG also argues that BPA will be unduly discriminatory if BPA does not offer service under the RL rate to public agency customers that participate in the REP, as well as IOUs. *Id.* at 3. WPAG reiterates these arguments in its brief on exceptions. WPAG Ex. Brief, WP-02-R-WA-01, at 2-8. The PPC notes that the exchange settlements are proposed to be offered to regional IOUs but have not been proposed to be offered to other regional utilities participating in the REP. PPC Brief, WP-02-B-PP-01, at 64.

MAC argues that the net cost of system augmentation for the Slice product should not include 990 aMW of purchases for the DSIs. MAC Brief, WP-02-B-MA-01, at 8. Similar arguments are made by PPC and SPG regarding BPA's PF Preference rate. PPC Brief, WP-02-B-PP-01, at 52; SPG Brief, WP-02-B-SG-01, at 13-15. SPG also argues that non-Federal resources should not be acquired to replace reductions in FBS capability. SPG Brief, WP-02-B-SG-01, at 14-15.

BPA's Position

BPA has properly developed the RL rate. Leathley *et al.*, WP-02-E-BPA-19, at 8-14; Doubleday *et al.*, WP-02-E-BPA-44, at 10-12. BPA has properly allocated purchased power costs. Doubleday *et al.*, WP-02-E-BPA-44, at 10-12. BPA is properly acquiring 1,282 aMW as FBS replacement resources. Loads and Resources Study Documentation, WP-02-FS-BPA-01A. BPA is required by law to provide RL service only to IOUs, and offering RL service only to the IOUs as part of a settlement of the REP is not unduly discriminatory.

Evaluation of Positions

WPAG argues that sections 7(b)(1) and 7(f) of the Northwest Power Act were intended to produce a PF rate that was lower than the rate under which BPA is authorized to offer requirements service to the loads of IOUs under the Northwest Power Act. WPAG Brief, WP-02-B-WA-01, at 5-6. WPAG argues that this is contrary to BPA providing requirements service to preference customers and IOUs at approximately the same rate. *Id.* at 6. BPA acknowledges that the implementation of those statutory provisions has generally resulted in a PF Preference rate lower than the NR rate. This is also true in this rate case. As discussed in greater detail below, however, section 7(f) of the Northwest Power Act permits the development of more than one rate for requirements service to IOUs. This permits the development of the RL rate, which applies to the special circumstances of the settlement of the REP with regional IOUs.

WPAG argues that a number of ratemaking actions BPA has taken are contrary to the Northwest Power Act. *Id.* The first action WPAG describes was that BPA acquired power that is not needed during the rate period to meet preference customer loads but is used instead to serve IOU loads. *Id*. at 7. WPAG also objects to the designation of purchased power as FBS replacement power. *Id.* WPAG argues that designating power as FBS replacements for the sole purpose of reducing the rate for requirements loads of IOUs is contrary to Northwest Power Act sections 7(b)(1) and 7(f). *Id.* Without citation to authority, WPAG argues that BPA should not have acquired power not needed to meet preference customer loads to replace the FBS. The Northwest Power Act, however, expressly grants BPA the authority to acquire resources to replace reductions in the capability of the FBS.

Section 3(10) of the Northwest Power Act defines FBS resources as: (1) the FCRPS hydroelectric projects; (2) resources acquired by the Administrator under long-term contracts in force on the effective date of this Northwest Power Act; and (3) resources acquired by the Administrator *in an amount necessary to replace reductions in the capability of the resources referred to in subparagraphs (1) and (2) of this paragraph*. 16 U.S.C. §839a(10) (emphasis added).

The Northwest Power Act expressly recognizes that the Administrator may acquire resources as needed to replace the reduced capability of the FBS. As noted in BPA's testimony, these reductions include the shutdown of the Trojan and Hanford nuclear plants (BPA's shares are 230 and 309 aMW, respectively); failure to complete Washington Nuclear Projects Nos. 1 and 3 (BPA's shares are 958 and 651 aMW, respectively); and hydroelectric capability losses

(521 aMW). Doubleday *et al.*, WP-02-E-BPA-44, at 7. These reductions total 2,669 aMW, which is far more than the amount of power BPA is acquiring for the coming rate period. In addition, the Northwest Power Act does not limit resource acquisitions to the amounts needed to meet preference loads. Section 6(a)(2) of the Northwest Power Act provides that:

> In addition to acquiring electric power pursuant to section 5(c), or on a short-term basis pursuant to section 11(b)(6)(i) of the Transmission System Act, *the Administrator shall acquire*, in accordance with this section, *sufficient resources to meet his contractual obligations* that remain after taking into account planned savings from measures provided in paragraph 1 of this subsection, and to assist in meeting the requirements of section 4(h) of this Northwest Power Act.

16 U.S.C. §839d(a)(2) (emphasis added).

In BPA's current rate case, because current power sales contracts will expire before the beginning of the next rate period, BPA must forecast its contractual obligations for the coming rate period. BPA's purchases are acquired to meet BPA's forecasted loads to BPA's preference customers, IOU customers, and the relevant portion of DSI customers and other contractual obligations. As noted in BPA's testimony, "BPA does not assume that costs of individual resources will be allocated to particular individual power sales." Doubleday *et al.*, WP-02-E-B-A-44, at 7. Also, as noted in the Northwest Power Act's rate directives, FBS resources are not allocated solely to BPA's preference customers, but also to exchanging utility customers and, depending on the size of the FBS, to other customers. In fact, the Northwest Power Act expressly recognizes that FBS resources, in the proper circumstances, may be allocated to the rates BPA establishes under section 7(f) of the Northwest Power Act, *e.g.*, the NR and RL rates. Section 7(f) of the Act states that "[r]ates for all other firm power sold by the Administrator for use in the Pacific Northwest shall be based upon the cost of the portions of FBS resources, [exchange resources] . . .and additional resources which, in the determination of the Administrator, are applicable to such sales." 16 U.S.C. §839e(f).

In a similar vein, MAC argues that the net cost of system augmentation for the Slice product should not include 990 aMW of power purchases for the DSIs. MAC Brief, WP-02-B-MA-01, at 8. The PPC argues that the DSIs should pay their own augmentation costs, because preference customers are exposed to market-based charges such as the TAC, TACUL, and SUMY. PPC Brief, WP-02-B-PP-01, at 52. SPG also argues that BPA should assign to the DSIs the cost of augmentation for the DSIs. SPG Brief, WP-02-B-SG-01, at 13-15. First, as noted above, BPA must forecast its contractual obligations for the coming rate period. BPA's purchases are acquired to meet BPA's forecasted loads to BPA's preference customers, IOU customers, and the relevant portion of DSI customers and other contractual obligations. BPA has the authority to replace reductions in the capability of the FBS. This increases the size of the FBS. Costs of the FBS are then allocated in accordance with BPA's rate directives. As noted in BPA's testimony, "BPA does not assume that costs of individual resources will be allocated to particular individual power sales." Doubleday *et al.*, WP-02-E-B-A-44, at 7. SPG argues that BPA proposes to sell DSI customers power from the FBS melded with power purchases specifically for service to the DSIs. SPG Brief, WP-02-B-SG-01, at 14. SPG has mischaracterized BPA's testimony. BPA's testimony states that "BPA will be purchasing approximately 1,562 aMW [of which 450 aMW are not FBS replacements, *see* WPRDS, WP-02-E-BPA-05, at 69] in order to have sufficient FBS resources to meet BPA's total Subscription load obligation during the FY 2002-2006 period. BPA, however, does not plan FBS replacement purchases on a customer class-by-customer class basis." Berwager *et al.*, WP-02-E-BPA-09, at 7.

SPG argues that BPA also stated that "the service to the DSI customers will be from the FBS, and because of that, all customers, both Slice and non-Slice customers will share in the costs of extending the Inventory Solution to include these sales to the DSI customers." SPG Brief, WP-02-B-SG-01, at 14, quoting Mesa *et al.*, WP-02-E-BPA-54, at 10. Both the SPG Brief and the Mesa testimony it quotes reference the testimony of Berwager *et al.*, WP-02-E-BPA-09. *Id.* As noted above, BPA does not plan FBS replacement purchases on a customer class by customer class basis. Berwager *et al.*, WP-02-E-BPA-09, at 7. Furthermore, the testimony cited by SPG concerns the actual "service" to the DSIs, as opposed to the ratemaking treatment of the IP rate class costs. The BPA witness is just stating the obvious, that all of BPA's actual load obligations, including preference customer load, IOU customer load, and DSI customer load, must be served with real power available to BPA. That power comes from the FBS. SPG notes that BPA testified during cross-examination that the proposed sale to the DSIs is not necessarily for replacement of the FBS. SPG Brief, WP-02-B-SG-01, at 14-15 SPG has mischaracterized BPA's cross-examination testimony. The BPA witness was asked if system augmentation was an FBS replacement. Tr. 218-19. The BPA witness answered that due to his imperfect knowledge of the statutory and legal connotations concerning replacements for the FBS, he did not feel competent to answer. *Id.* Nowhere in the testimony did the witness mention the DSIs. *Id.* In summary, BPA may purchase power to replace reductions in the capability of the FBS and may acquire power to meet its forecasted contractual obligations to its customers. The costs of such power are properly allocated under BPA's rate directives and may be incurred by BPA's customers. That some of BPA's power may be used to serve a portion of DSI loads is appropriate.

SPG also argues that BPA must acquire any non-Federal resources to replace the reductions in FBS capability in accordance with the requirements of section 6(b)(4) of the Northwest Power Act. SPG Brief, WP-02-B-SG-01, at 14-15. SPG argues that BPA's testimony indicates that BPA has not conducted the steps necessary if power purchases for the DSI customers are FBS replacements. *Id.;* Tr. 220, lines 2-15. This argument mischaracterizes BPA's testimony. BPA's witness correctly notes that "these are purchases that we believe are necessary in order to meet forecasted load commitments from the total customer classes that we expect to place load on us." Tr. 220, lines 9-12. BPA's witness noted earlier that he was unfamiliar with the concept of FBS replacements. BPA's witness stated that "I do not believe that I have a perfect understanding of what an FBS replacement, versus an FBS decision, versus general augmentation is. So I guess I will have to say that I believe that that has specific statutory and legal connotation that I do not feel competent to answer perfectly at this point, as to whether they are FBS replacement purchases, *per se*." Tr. 218-19. Simply because this particular witness did not understand the legal implications of FBS replacements does not mean that BPA has not conducted the steps necessary to purchase power for FBS replacements. The record is quite clear regarding BPA's proposal in this rate case to replace reductions in the capability of the FBS with power purchases.

BPA clearly proposed to replace reductions in the capability of the FBS with purchases in BPA's initial proposal. For example, "BPA will be purchasing approximately 1,562 aMW [of which 450 aMW are not FBS replacements, *see* WPRDS, WP-02-E-BPA-05, at 69] in order to have sufficient FBS resources to meet BPA's total Subscription load obligation during the FY 2002-2006 period." Berwager *et al.*, WP-02-E-BPA-09, at 7. Similarly, BPA noted that "BPA has assumed that it will need to increase its power inventory to meet its customers' Subscription purchases. The power added to the inventory is defined as FBS replacements and enables BPA to achieve load/resource balance on an annual basis. The cost of the purchased power is treated as part of the total cost of FBS resources for ratemaking purposes." Doubleday *et al.*, WP-02-E-BPA-18, at 7. Furthermore, "BPA is acquiring a substantial amount of system augmentation to meet its forecasted firm loads during the rate period. Some of these firm loads include sales to the DSIs and IOUs. BPA's power purchases replace reductions in the capability of the FBS. The costs of the FBS, including FBS replacements, are allocated to all rate classes served by the FBS." Doubleday *et al.*, WP-02-E-BPA-44, at 10. As noted previously, BPA has the authority to acquire power "in an amount necessary to replace reductions in the capability of the [FBS] resources." 16 U.S.C. §839a(10). BPA's testimony established that these reductions total 2,669 aMW, which is far more than the amount of power BPA is acquiring for the coming rate period. Doubleday *et al.*, WP-02-E-BPA-44, at 7. In addition, the Northwest Power Act authorizes the BPA Administrator to acquire "sufficient resources to meet [her] contractual obligations." 16 U.S.C. §839d(a)(2). BPA also clearly identified the proposed price for the purchases in BPA's initial proposal. Oliver *et al.*, WP-02-E-BPA-20. These purchases are clearly economically prudent acquisitions. *Id.*

With regard to an additional claim that BPA has not complied with the Northwest Power Act, such an issue must begin with review of the Northwest Power Act itself. Section 6(b)(4) of the Northwest Power Act provides:

> The Administrator shall acquire any non-Federal resources to replace FBS resources only in accordance with the provisions of this section. The Administrator shall include in the contracts for the acquisition of any such non-Federal replacement resources provisions which will enable [her] to ensure that such non-Federal replacement resources are developed and operated in a manner inconsistent with the considerations specified in section 4(e)(2) of this Northwest Power Act.

16 U.S.C. §839d(b)(4). Section 4(e)(2) of the Northwest Power Act provides:

> The plan shall set forth a general scheme for implementing conservation measures and developing resources pursuant to section 6 of this Northwest Power Act to reduce or meet the Administrator's obligations with due consideration by the NWPPC for: (1) environmental quality; (2) compatibility with the existing regional power system; (3) protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish; and (4) other criteria which may be set forth in the plan.

16 U.S.C. §839b(e)(2).

The FBS replacements, comprised of power purchases, are being acquired in accordance with section 6(b)(4) and meet the criteria of section 4(e)(2). BPA analyzed the use of power purchases in its 1995 BPA Business Plan (DOE/BP-2664). The Administrator notes this previous administrative decision. The Business Plan specified that BPA would rely on power purchases and nonfirm energy to meet load.

> BPA must be careful not to make long-term commitments to acquire power resources for loads it may not have; *i.e*., loads that move away from BPA service and obtain their power from BPA's competitors. In addition, because the operation of the hydrosystem has changed to provide additional flows for migrating salmon, there is a vast amount of very low-cost hydropower in the spring that makes almost any other type of generation unnecessary during the flow periods. If a new resource cannot shutdown during spring flow period, BPA will be unable to take advantage of the required spring flows to reduce costs to its customers. These conditions demand resource flexibility, as well as low cost…The type of resource that fits best with the existing system under present conditions is a resource that can operate economically during periods of low hydro generation, but which can be shutoff without incurring large costs when flows are high, whether the high flows are the result of good water years or fish flow requirements . . . only one type of resource fully meets these conditions: spot market power purchases. Power purchases are particularly attractive because they do not require capital investment or long-term financial obligations for BPA as a purchaser.

1995 BPA Business Plan, at 34.

This decision was confirmed in the BPA Business Plan Final Environmental Impact Statement (BP FEIS) that accompanied the Business Plan. Specifically, section 2.4.3.2 reviews BPA's resource priorities under the Northwest Power Act. BP FEIS at 2-26. Furthermore, BPA's Subscription Strategy NEPA ROD states that BPA does not intend to rely on the long-term acquisition of the output of new generation resources to meet any increases in its loads. Instead, BPA plans to use cost-effective power purchases. Subscription Strategy NEPA ROD at 18. For these reasons, power purchases are consistent with the criteria of section 4(e)(2), because power purchases meet the considerations for environmental quality, compatibility with the existing regional power system, fish and wildlife concerns, and other considerations related to cost effectiveness. Moreover, consistent with section 6(a)(1) of the Northwest Power Act, BPA has taken into account planned savings from conservation and renewable resources. As BPA has proceeded with augmentation of the Federal system to meet loads forecast to be served under Subscription, BPA has reviewed the role conservation should play in augmentation. Oliver *et al.*, WP-02-E-BPA-45, at 8. BPA proposed that 12 aMW of conservation resources, on an annual basis, will be targeted for acquisition. *Id.* BPA set this target based on the current 1998 Northwest Conservation and Electric Power Plan. *Id. See also* NWPPC Issue Paper 99-18, *Bonneville Conservation Acquisition 2002-2006*, which estimates the amount of cost-effective conservation available consistent with the NWPPC's 1998 Plan at 150 aMW over the rate period.

Issue Paper 99-18 at 14. Over the rate period, BPA plans to implement a total of 150 aMW from all BPA-sponsored conservation activities. *Id.*

WPAG argues that BPA has misapprehended its authority to replace lost FBS capability. WPAG Ex. Brief, WP-02-R-WA-01, at 4-5. WPAG argues that BPA's authority under section 6(a)(2) of the Northwest Power Act to acquire replacements for lost FBS capability is limited to resources, which means actual or planned electric power capability of generating resources. *Id*. WPAG argues that this definition does not denominate as an FBS replacement a short-term market purchase made pursuant to section 11(b)(6)(i) of the Transmission System Act. *Id*. First, WPAG cites no record evidence that BPA is relying on section 11(b)(6)(i) of the Transmission System Act to make its short-term (five-year) power purchases. In fact, BPA is relying on its authority to make five-year purchases under section 6 of the Northwest Power Act. Regardless, however, WPAG has misinterpreted the Northwest Power Act. WPAG failed to include the full relevant text of the Act's definition of "resource." The Northwest Power Act defines "resource," in part, as "*electric power, including* the actual or planned electric power capability of generating facilities." 16 U.S.C. §839a(19)(A). The Northwest Power Act's definition thus references *electric power* from whatever source, which would include market purchases, and merely notes that included as two examples of this electric power are the actual or planned electric power capability of generating facilities. Supporting this construction is the fact that the Northwest Power Act defines "electric power" as "electric peaking capacity, or electric energy, or both." 16 U.S.C. §839a(9). BPA's power purchases from the market are therefore clearly consistent with the definition of "resource" in the Northwest Power Act. WPAG argues that its conclusion is supported by section 6(b)(4) of the Northwest Power Act, which requires that the acquisition of any non-Federal resources by BPA to replace lost FBS capability must be in accordance with section 6 of the Northwest Power Act. *Id*. This argument is difficult to understand. Section 6 of the Northwest Power Act is a lengthy section of the statute. WPAG does not identify which provisions of section 6 are alleged to be inconsistent with BPA's proposal. Without knowing these provisions, BPA is unsure of WPAG's arguments. WPAG also argues that short-term market purchases cannot be FBS replacements under sections 6(a)(2) and 6(b)(4) of the Northwest Power Act. *Id*. BPA, however, has discussed its compliance with sections 6(a)(2) and 6(b)(4) of the Northwest Power Act in section 12.3 of this chapter. WPAG argues that since the short-term market purchases that BPA proposes to make cannot be denominated FBS replacements, their costs cannot, consistent with section 7(b)(1) of the Northwest Power Act, be included in the costs allocated to the PF rate. WPAG Ex. Brief, WP-02-R-WA-01, at 5. As noted in the foregoing discussion, BPA's market purchases are clearly resources under the Northwest Power Act and are also FBS replacement resources. The costs of these resources are properly allocated to the PF Preference rate. Doubleday *et al.*, WP-02-E-BPA-44, at 10. In summary, BPA intends to acquire the amount and type of resources noted above as FBS replacement resources.

WPAG argues that the record makes it abundantly clear that augmentation power purchases that BPA intends to make during the rate period are solely for the purpose of making power sales to the IOUs under the RL rate. WPAG Ex. Brief, WP-02-R-WA-01, at 3, citing Doubleday *et al.*, WP-02-E-BPA-44, at 10-11. WPAG has misrepresented BPA's rebuttal testimony. The cited testimony does not indicate that system augmentation purchases are made solely to support RL rate sales. The testimony states: "BPA is acquiring a substantial amount of system augmentation to meet its forecasted firm loads during the rate period. *Some of these firm loads include sales to the DSIs and IOUs*." Doubleday *et al.*, WP-02-E-BPA-44, at 10, lines 20-22 (emphasis added). Clearly, system augmentation amounts are associated with BPA's total firm load obligation. WPAG argues that the power needed to effectuate the REP settlement will be purchased in the market and denominated as FBS replacement power, permitting BPA to allocate a large portion of the costs of this power to preference customers. WPAG Ex. Brief, WP-02-R-WA-01, at 3. As noted above, BPA's purchases are acquired to meet BPA's forecasted loads to BPA's preference customers, IOU customers, and the relevant portion of DSI customers and other contractual obligations. As noted in BPA's testimony, "BPA does not assume that costs of individual resources will be allocated to particular individual power sales." Doubleday *et al.*, WP-02-E-BPA-44, at 7.

SPG argues that BPA proposes to spread the costs of power purchases for the DSIs over other rate classes. SPG Brief, WP-02-B-SG-01, at 14-15. SPG argues that BPA's rates for preference and Federal agency customers must be based on only the costs of those FBS resources and power purchases necessary to meet the loads of these customer classes, citing section 7(b)(1) of the Northwest Power Act, 16 U.S.C. §839e(b)(1). *Id.* SPG has misapplied section 7(b)(1) of the Northwest Power Act. Section 7(b)(1) provides:

> The Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the PNW, and loads of electric utilities under section 5(c). Such rate or rates shall recover the costs of that portion of the FBS resources needed to supply such loads until such sales exceed the FBS resources. Thereafter, such rate or rates shall recover the cost of additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under section 5(c) and then from other resources.

16 U.S.C. §839e(b)(1).

BPA is expressly complying with this provision. The FBS is a single resource pool and is not divided into separately priced portions that serve any particular customer class. As noted earlier, BPA has the authority to replace reductions in the capability of the FBS resources. BPA also has authority to purchase power to meet its forecasted contractual obligations to its customers. The amount of BPA's proposed augmentation purchases is well below the amount of the reductions in the capability of the FBS that BPA is authorized to replace. BPA's purchases, as FBS replacements, increase the size of the FBS. However, BPA's rates for preference customers and Federal agency customers are still recovering the costs of only that portion of the FBS resources needed to supply such loads. Remaining FBS resources are allocated in accordance with the rate directives. The Northwest Power Act expressly recognizes that the FBS may exceed the requirements of its preference customers. For example, section 7(f) of the Northwest Power Act notes that "all other firm power sold by the Administrator for use in the PNW shall be based upon the cost of the portions of *FBS resources*, purchases of power under section 5(c) of this Northwest Power Act and additional resources which, in the determination of the Administrator, are applicable to such sales." 16 U.S.C. §839e(f) (emphasis added). It is therefore, clear that section 7(b)(1) does not prohibit purchases to replace reductions in the capability of the FBS.

Once the FBS was determined, BPA properly allocated to the PF Preference rate "the costs of that portion of the FBS resources needed to supply such loads." 16 U.S.C. §839e(b)(1).

WPAG notes that BPA is proposing an RL rate to provide requirements service to IOUs. WPAG Brief, WP-02-B-WA-01, at 7. Without citation to evidence, WPAG argues that the fact that the RL rate is a requirements rate is to avoid recall provisions to which BPA's surplus power sales are subject. *Id.* BPA did not propose requirements sales to IOUs simply to avoid recall provisions for sales of surplus power. BPA is authorized to make sales to IOUs under a number of statutory provisions. BPA may sell requirements power to the IOUs under section 5(b) of the Northwest Power Act. 16 U.S.C. §839c(b). BPA may sell in-lieu power to the IOUs under section 5(c)(5) of the Northwest Power Act. 16 U.S.C. §839c(c)(5). BPA may also sell power to the IOUs pursuant to section 5(f) of the Northwest Power Act. 16 U.S.C. §839c(f). BPA determined that it is appropriate to offer requirements power to the IOUs, because the IOUs have a right to such power purchases, and such power sales were an appropriate part of the consideration for the proposed Residential Exchange settlements. Doubleday *et al.*, WP-02-E-BPA-44, at 13. In addition, in the Subscription Strategy, BPA concluded that net requirements power sales could be a component of a settlement of the REP with the IOUs. Leathley *et al.*, WP-02-E-BPA-19, at 9. There is no requirement that BPA must sell the IOUs only surplus power for Residential Exchange settlements. *See* 16 U.S.C. §832a(f).

WPAG argues that augmentation costs must be allocated to the RL rate. WPAG Ex. Brief, WP-02-R-WA-01, at 2. WPAG also argues that the RL rate is inconsistent with the resource cost allocations of section 7(f) of the Northwest Power Act, because it does not include all of the costs of power that BPA will acquire for serving the IOU loads. WPAG Brief, WP-02-B-WA-01, at 7. These arguments are not persuasive. As noted above, the Northwest Power Act does not prohibit BPA from acquiring power to replace the FBS and to meet its forecasted contractual load obligations. Furthermore, the costs of system augmentation purchases that replace some of these reductions in capability of the FBS are melded with all other FBS resource costs before cost allocation to rate pools is performed. Doubleday *et al.*, WP-02-E-BPA-44, at 7. BPA, therefore has not, as alleged by WPAG, acquired power for the purpose of serving particular IOU loads or any other particular load. The costs of the FBS, including FBS replacements, are allocated to all rate classes served by the FBS. *Id.* Because BPA's preference customers are served with FBS resources, they bear some of these costs. *Id.* This treatment is consistent with BPA's Subscription Strategy goals of spreading the benefits of Federal power widely in the region while avoiding a PF Preference rate increase. *Id.* at 10-11. *See* Burns and Elizalde, WP-02-E-BPA-08, at 7.

Furthermore, in the Subscription Step, BPA assumes that the 1,000 aMW sale to as-yet unidentified Northwest customers under the FPS-96 rate schedule in the Rate Design Step no longer occurs, and is replaced by a sale to the IOUs at either the RL-02 or the PF Exchange Subscription rate. Leathley *et al.*, WP-02-E-BPA-19, at 13. The costs recovered by the FPS sale in the Rate Design Step are the same basic costs recovered by the RL/PF Exchange Subscription sale. *Id.* This provides the foundation for establishment of the RL-02 rate. *Id.* The FPS-96 rate is a section 7(f) rate, and costs are allocated to FPS loads following the 7(f) rate directives. The RL rate cost basis in the Subscription Step, as discussed above, is based on an FPS-96 cost basis in the Rate Design Step. Therefore, the RL rate cost basis is supported by the 7(f) rate directives.

In addition, section 7(f) of the Northwest Power Act supports the development of the RL rate. Section 7(f) provides:

> Rates for all other firm power sold by the Administrator for use in the PNW shall be based upon the cost of the portions of FBS resources, purchases of power under section 5(c) of this Northwest Power Act and additional resources which, in the determination of the Administrator, are applicable to such sales.

16 U.S.C. §839e(f).

These "other firm power" sales include requirements sales to regional IOUs. The legislative history of the Northwest Power Act establishes that BPA may establish more than one rate under section 7(f). The report of the House Committee on Interstate and Foreign Commerce states:

> Section 7(f) establishes the rate or rates for sales to IOUs other than sales pursuant to the section 5(c) exchange, preference customers for power needed to meet the requirements of new large single "loads" and all other miscellaneous sales. This rate has sometimes been called a new resource rate and *does not preclude the establishment of more than one rate under this provision if circumstances make a separate rate for a separate load or demand necessary or appropriate*.

H.R. Rep. No. 976, 96th Cong. 2d Sess. 69 (1980) (emphasis added).

As established in BPA's testimony, current circumstances make the establishment of a separate rate for a separate IOU load or demand both necessary and appropriate. Leathley *et al.*, WP-02-E-BPA-19, at 9. IOUs have the right to make net requirements power purchases from BPA. 16 U.S.C. §839c(b)(1). IOUs have the right to participate in the REP. 16 U.S.C. §839c(c). In its Subscription Strategy, as noted above, BPA concluded that net requirements power sales could be a component of a settlement of the REP with the IOUs. Leathley *et al.*, WP-02-E-BPA-19, at 9.

As noted above, current circumstances make the establishment of a separate rate for a specified separate IOU load or demand both necessary and appropriate. *Id.* These circumstances involve, in part, the REP. *Id.* The REP has been in existence since shortly after enactment of the Northwest Power Act. *Id.* BPA has implemented the program for approximately 18 years. *Id.* During that time, BPA has learned what is required to implement the program and the costs and benefits of implementing the program. *Id.* For example, BPA must negotiate RPSAs with exchanging utilities. *Id.* These negotiations are contentious, lengthy, and demanding of the agency's and customers' resources. *Id.* at 9-10. Disputes regarding implementation of the RPSAs and the litigation of such disputes require additional resources to resolve. *Id.* at 10.

In addition, BPA establishes an ASC Methodology, which is used to calculate the ASCs of exchanging utilities. *Id.* The administrative establishment or revision of the ASC Methodology is extremely contentious. *Id.* Revision of the ASC Methodology in 1984 led to extensive disagreements and litigation among BPA customers and other interested parties in the region. *Id.* This process and litigation proved expensive and taxing for all parties. *Id.*

In implementing the REP, BPA must also review ASC filings made by the exchanging utilities. *Id.* The utilities' ASC filings can be great in number and extremely technical. *Id.* BPA's review of the ASC filings demands the dedication of numerous BPA employees or contract employees, or both. *Id.* BPA's ASC reports are then filed by the IOUs with FERC for review. *Id.* These reviews are also contentious and demand the expenditure of BPA's, the utilities' and interested parties' resources. *Id.* The exchanging utilities can also appeal FERC's decisions to the United States Court of Appeals for the Ninth Circuit. *Id.* These reviews are also contentious and demand the expenditure of BPA's, the utilities' and interested parties' resources. *Id.*

Furthermore, the determination of exchange benefits, as noted previously, is based in part on the level of the applicable PF Exchange rate. *Id.* If the PF Exchange rate is low, benefits are increased. *Id.* If the PF Exchange rate is high, benefits are reduced. *Id.* This leads to additional contentiousness in BPA's rate hearings. *Id.* BPA's rates are reviewed by FERC for confirmation and approval and may be appealed to the United States Court of Appeals for the Ninth Circuit. *Id.* These reviews are also contentious and demand the expenditure of BPA's, the utilities' and interested parties' resources. *Id.*

In light of these difficulties, beginning in 1981, BPA and exchanging utilities executed RPSAs for 20 year terms. *Id.* Between 1981 and today, all of these RPSAs have been settled except for one, which is between BPA and a utility in deemer status. *Id.* at 10-11. (Deemer status is where a utility sets its ASC equal to BPA's PF Exchange rate and does not receive positive benefits, but accrues a negative balance that must be eliminated before resuming the receipt of positive benefits.) *Id.* at 11. *See* Boling and Doubleday, WP-02-E-BPA-30. This extremely large number of Residential Exchange settlements reflects the nature and benefits of such settlements. Leathley *et al.*, WP-02-E-BPA-19, at 11. Parties are able to avoid the contentiousness of the myriad Residential Exchange issues, thereby saving significant administrative and legal expenses. *Id.* Parties receive known benefits instead of guessing future benefits due to changes in the ASC Methodology, the determination of ASC reports, and the development of wholesale power rates. *Id.* This enables parties to engage in better financial planning. *Id.*

The foregoing circumstances support the development of the RL rate. *Id.* The RL-02 rate applies only to net requirements sales to IOUs where the IOUs agree to a settlement of the REP. *Id.* As noted in BPA's Subscription Strategy:

> In Subscription, BPA proposes a settlement in which residential and small farm loads of the IOUs will be assured access to the equivalent of 1,800 aMW of Federal power for the 2002-2006 period. Of this amount, at least 1,000 aMW will be met with actual power deliveries, depending on which approach is most cost-effective for BPA.

Id.

While BPA proposed to offer a settlement based on the equivalent of 1,800 or 1,900 aMW of Federal power, the residential and small farm loads of the IOUs that will be eligible for participation in the Residential Exchange after 2001 total approximately 4,500 aMW. *Id.* Thus, under the proposed settlement, the IOUs are foregoing their rights to exchange their total residential and small farm loads for the receipt of the equivalent of 1,800 [1,900] aMW of Federal power, a much smaller amount than their total exchangeable loads. *Id.*

In addition, BPA does not know whether the IOUs will continue the traditional REP or will choose to participate in a settlement of the REP through Subscription. *Id.* at 11-12. BPA has therefore developed rates that will apply under each scenario. *Id.* at 12.

Additional support for the RL-02 rate is found in the manner in which Federal power is made available to BPA's customers. *Id.* at 13. As noted previously, the REP provides a monetary form of access to Federal power for regional utilities. *Id.* In recent years, however, the benefits available to the residential consumers of IOUs from the REP have decreased substantially from the benefits provided in earlier years. *Id.* Because of the decline in these benefits, certain parties have argued that the residential consumers of the region's IOUs are being denied proper access to Federal power. *Id.* Under Subscription, BPA proposed a settlement of the REP in which IOUs could purchase Federal power for a portion of their net requirements loads at competitive rates. *Id.* BPA believes that providing the IOUs the ability to purchase a specified amount of power at competitive rates contributes to the widespread use of Federal power. *Id.*

The establishment of the RL-02 rate is also consistent with regional discussions in the Comprehensive Review and in the development of BPA's Subscription Strategy. *Id.* In the Comprehensive Review, the Steering Committee encouraged parties to continue settlement discussions and to explore other paths to ensure that residential and small farm loads receive an equitable share of the benefits of the Federal system. *Id.;* Comprehensive Review, Final Report, at 14. The Comprehensive Review also noted the desire to make power sales to BPA's customers at cost. Leathley *et al.*, WP-02-E-BPA-19, at 13. While the Final Report did not expressly state that all BPA rates would be equal, some customer groups suggested that this was the basic intent. *Id.* at 13-14. These positions were reflected in comments made during the Subscription process by certain customer groups, including the IOUs and the DSIs, regarding their respective rates. *Id.* at 14. In the Subscription Strategy, BPA acknowledged these parties' understandings, stating BPA's expectation that "[t]hese sales [to IOUs] will be at a rate approximately equal to the PF Preference rate, subject to establishment in BPA's rate case and consistent with BPA's rate directives." *Id.;* Subscription Strategy at 16.

WPAG argues that the RL rate is arbitrarily set at a level equal to the PF Preference rate. WPAG Brief, WP-02-B-WA-01, at 8. This argument is refuted by the record. As noted in BPA's Subscription Strategy, which contemplates the traditional REP as well as proposed settlements of that program, BPA's goals include spreading the benefits of Federal power and avoiding increases in BPA's PF Preference rate. *See* Burns and Elizalde, WP-02-E-BPA-08, at 7. In the past, BPA's general business goals have also been to provide rate stability in the region while serving BPA's loads. Doubleday *et al.*, WP-02-E-BPA-44, at 6. The Subscription Strategy goals mentioned above are the latest expression of these long-held business goals. *Id.* BPA has determined that it can provide 1,000 aMW of additional power to its customers and not increase the PF Preference rate. *Id.* BPA has assumed an FPS rate equal to the 1996 PF Preference rate as a reasonable price for such sales. *Id.* BPA's proposed sale of 1,000 aMW in the Rate Design Step is consistent with the Subscription Strategy and is also consistent with BPA's long-held business goals. *Id.* In the Subscription Step, BPA assumes that the IOUs accept the Subscription settlement proposal and that 1,000 aMW is made available to the IOUs in power and 800 [900] aMW in monetary benefits. *Id.* *See* Leathley *et al.*, WP-02-E-BPA-19, at 12. The costs recovered by the FPS sale in the Rate Design Step are the same basic costs recovered by the RL/PF Exchange Subscription sale. This provides the foundation for establishment of the RL-02 rate. Leathley *et al.*, WP-02-E-BPA-19, at 13. Therefore, at the beginning of the Subscription Step, the RL rate is set at a PF-96 equivalent level. This level is similar to the PF-02 level. The Subscription Step section takes the results of the Rate Design Step and adjusts them by the added credits and costs associated with BPA's Subscription Strategy policies. Doubleday *et al.*, WP-02-E-BPA-18, at 17. In the Subscription Step, the RAM equitably allocates the net cost of the REP credit, a benefit not otherwise allocated under section 7 of the Northwest Power Act, to the PF Preference class, the IP-02 class, and the RL-02 class. *Id.* at 19. This allocation of credits achieves the Subscription Strategy expectation that PF Preference class customers, IP-02 class customers, and RL-02 class customers would pay similar rates for similar products, while maintaining the PF-IP relationship in section 7(c) of the Northwest Power Act. *Id.* *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, section 2.4, Tables SUBSCR 01, SUBSCR 02, SUBSCR 03, SUBSCR 04. As shown by the well-documented and logical steps above, BPA was not arbitrary in setting the RL rate at a level equal to the PF Preference rate.

WPAG argues that in BPA's initial proposal, BPA proposed that up to 800 [900] aMW of the proposed settlement would be provided to the IOUs as a cash payment. WPAG Ex. Brief, WP-02-R-WA-01, at 5, citing Leathley *et al*., WP-02-E-BPA-19, at 12, 19. The cited testimony, however, does not contain the statements alleged by WPAG. There is no mention of the 800 [900] aMW portion of the IOU settlements on page 12 of the cited testimony, and there is no page 19 of the cited testimony. WPAG argues that BPA now takes the position that the cash payment portion of the settlement is not part of the rate case, but will be decided in a separate process. *Id*., citing Draft ROD, WP-02-A-01, at 12-21. BPA does not understand this assertion. First, WPAG's citation relates only to a reiteration of BPA's Subscription Strategy regarding the proposed IOU settlements. It simply notes that BPA proposes a minimum of 1,000 aMW of power and 800 [900] aMW of monetary benefits. Leathley *et al*., WP-02-E-BPA-19, at 12-13, 16. Ever since the issuance of BPA's Subscription Strategy, BPA's IOU settlement proposal has always been to provide 1,000 aMW of power and 800 [900] aMW of monetary benefits. *Id*. The monetary benefits will be calculated on the basis of the difference between BPA's five-year flat-block market price forecast and the rate that the IOUs pay for their Subscription power purchases. *Id*. Both BPA's five-year flat-block market price forecast and the rate that the IOUs pay for their Subscription power purchases are issues that are resolved in the rate case. In addition, the IOU settlement agreements must be negotiated between the parties. In the case of the proposed IOU settlement agreements, BPA has established that BPA will be conducting a 30-day public comment process on the proposed settlements in which parties may comment on issues regarding the propriety of the proposed settlements. WPAG argues that this contradicts BPA's argument that in order to perform the Subscription Step, BPA assumes that the IOUs accept the proposed settlement, with 1,000 aMW delivered as actual power and 800 [900] aMW provided as monetary benefits. WPAG Ex. Brief, WP-02-R-WA-01, at 5, citing Draft ROD, WP-02-A-01, at 12-10. WPAG argues that if the amount and costs of monetary benefits to be provided to the IOUs under the proposed settlement were used as an integral part of the case to calculate the RL rate in the Subscription Step, they cannot be treated as a separate matter to be dealt with outside of the rate case when the legality of the cash payments under the Northwest Power Act rate directives is called into question. *Id*. at 5-6. BPA believes that WPAG misunderstands BPA's proposal. BPA has been consistently clear that its IOU settlement proposal is for 1,800 aMW (now 1,900 aMW), which is comprised of forecasted minimum power sales of 1,000 aMW and 800 [900] aMW of monetary benefits. Leathley *et al*., WP-02-E-BPA-19, at 12-13, 16. With this information, BPA can develop the costs that are used to develop the RL rate in the Subscription Step. The actual negotiation and development of the settlement agreements are not conducted in the rate case but will reflect this structure. *Id*. Cash payments are not being made under the Northwest Power Act's rate directives. Rather, under the settlement authority granted BPA under section 2(f) of the Bonneville Project Act and as affirmed in section 9(a) of the Northwest Power Act, BPA is using endpoints established in BPA's rate case as the basis for calculating the monetary settlement benefits. It is appropriate to reflect the proposed power and monetary elements of the settlement, because BPA must forecast its loads and resources for the coming rate period and, given that BPA has proposed to offer REP settlements to the IOUs, the best information available must be used to reflect those proposed offers in BPA's rates. BPA believes that its settlement proposal is lawful and BPA is using the best information available to forecast the costs of the proposed settlements.

WPAG argues that including a monetary payment obligation in conjunction with a rate that is providing requirements service is beyond BPA's authority under section 7(f) of the Northwest Power Act. WPAG Ex. Brief, WP-02-R-WA-01, at 6. Again, section 7(f) of the Northwest Power Act is the statutory provision that provides for the establishment of rates for net requirements sales to IOUs. 16 U.S.C. §839e(f). BPA is using section 7(f) to establish the RL rate. The use of the RL rate as one endpoint in the calculation of monetary settlement payments is perfectly consistent with section 7(f). The difference between BPA's five year flat-block price forecast and the rate paid by the IOUs for the settlement power sales has long been the basis of the proposed settlement that provides the IOUs appropriate consideration for the termination of their participation in the REP. Leathley *et al*., WP-02-E-BPA-19, at 12-13, 16. These endpoints could have been other items, such as a fixed numerical point or an index. The RL rate is used as an endpoint in calculating the monetary payment portion of the settlement to establish appropriate consideration for the settlement. This is perfectly consistent with the Northwest Power Act.

WPAG argues that while section 2(f) of the Bonneville Project Act grants BPA the authority to settle claims, it is a prerequisite that a claim actually be asserted. WPAG Ex. Brief, WP-02-R-WA-01, at 6. WPAG argues that the record is bereft of any claim by the IOUs cognizable under section 2(f) of the Bonneville Project Act. *Id*. WPAG argues that the Draft ROD attempts to remedy this absence by listing a number of future problems that may be asserted by a party under the REP to be implemented in 2001. *Id*., citing Draft ROD, WP-02-A-01, at 12-24. WPAG argues that this attempt to manufacture a claim is of no avail, since mere assertions in a brief do not constitute evidence in the record. *Id*. WPAG has mischaracterized BPA's Draft ROD and the record in this proceeding. BPA expressly noted the obvious, that the IOUs' outstanding claim is the prospective implementation of the REP under RPSAs during the coming rate and contract periods. Draft ROD, WP-02-A-01, at 12-24; Leathley *et al*., WP-02-E-BPA-19, at 11. BPA also noted that the IOUs' claim is their statutory *right* to participate in the REP. 16 U.S.C. 839c(c)(1). As the record shows, this is a substantial claim, involving some $183 million in BPA's initial proposal, Wholesale Power Rate

Development Study Documentation, WP-02-E-BPA-05A, at 91, and $240 million during the coming rate period, Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A. BPA also explained the many reasons supporting previous settlements of the REP, which also apply to settlements of the implementation of the program in the next rate period. Leathley, *et al*., WP-02-E-BPA-19, at 8-14. *Id*. There can be no dispute that this extensive information is in the record. This record evidence clearly establishes the IOUs' claim that is the basis for the settlement.

WPAG argues that BPA's interpretation of its settlement authority under section 2(f) would render the Northwest Power Act's rate directives meaningless. WPAG Ex. Brief, WP-02-R-WA-01, at 7. WPAG argues that BPA's interpretation would have made it unnecessary to include sections 5(c) and 7(b) in the Northwest Power Act in order to implement the REP, because BPA already had the authority to make cash payments to the IOUs as part of a sale of requirements power in order to settle claims that had not yet been asserted. *Id*. This argument is based on faulty logic. Sections 5(c) and 7(b) of the Northwest Power Act are necessary elements for the existence of the REP. The REP is based on the determination of a utility's ASC, the determination of the PF Exchange rate, the determination of the utility's residential load, and many other factors. 16 U.S.C. §839c(c); Boling *et al*., WP-02-E-BPA-30. Sales of power and money do not create an REP. The REP is a statutory right of regional utilities for which participation can be terminated through a settlement. WPAG's argument is also based on faulty presumptions. First, as explained above and in greater detail in BPA's testimony cited above, the IOUs have a claim that has been asserted. The IOUs have a statutory *right* to participate in the REP. 16 U.S.C. §839c(c)(1). As noted in BPA's Letter Request for Comment on Prototype RPSA and IOU Settlement Agreements, IOUs must request participation under section 5(c) of the Northwest Power Act in order to have an RPSA or settlement agreement. Because BPA does not know its load obligations at this time, BPA must forecast the IOUs' participation in the proposed settlements. BPA is therefore not making cash payments as part of requirements sales for claims that have not been asserted. While any settlement agreements will not be effective until such agreements are executed by the parties, BPA must forecast the IOUs' settlement of their rights to participation in the REP and develop rates that apply to the proposed settlements.

WPAG argues that section 2(f) of the Bonneville Project Act does not grant BPA authority to set requirements rates in a manner that is not authorized by section 7 of the Northwest Power Act. WPAG Ex. Brief, WP-02-R-WA-01, at 7. WPAG argues that the only rate under which BPA is authorized by the Northwest Power Act to make cash payments is section 7(b) in conjunction with the REP established in section 5(c). *Id*. WPAG argues that BPA cannot use section 2(f) to create ratemaking authority it lacks under section 7(f) of the Northwest Power Act. *Id*. WPAG misunderstands BPA's proposed settlements. BPA is not relying on section 2(f) to set any requirements rates. BPA is relying on section 7(f) of the Northwest Power Act, 16 U.S.C. §839e(f), its legislative history, and testimony to develop the RL rate. *See* Leathley *et al*., WP-02-E-BPA-19, at 8-14; 16 U.S.C. §839e(f). Section 7(f) power sales include requirements sales to regional IOUs. The legislative history of the Northwest Power Act establishes that BPA may establish more than one rate under section 7(f). The report of the House Committee on Interstate and Foreign Commerce states:

> Section 7(f) establishes the rate or rates for sales to IOUs other than sales pursuant to the section 5(c) exchange, preference customers for power needed to meet the requirements of new large single "loads" and all other miscellaneous sales. This rate has sometimes been called a new resource rate and *does not preclude the establishment of more than one rate under this provision if circumstances make a separate rate for a separate load or demand necessary or appropriate*.

H.R. Rep. No. 976, 96th Cong. 2d Sess. 69 (1980) (emphasis added).

As established in BPA's testimony, current circumstances make the establishment of a separate rate for a separate IOU load or demand both necessary and appropriate. Leathley *et al.*, WP-02-E-BPA-19, at 9. IOUs have the right to make net requirements power purchases from BPA. 16 U.S.C. §839c(b)(1). IOUs have the right to participate in the REP. 16 U.S.C. §839c(c). In its Subscription Strategy, as noted above, BPA concluded that net requirements power sales could be a component of a settlement of the REP with the IOUs. Leathley *et al.*, WP-02-E-BPA-19, at 9. BPA has therefore not used section 2(f) of the Bonneville Project Act to establish the RL rate.

As noted above, WPAG argues that the only rate under which BPA is authorized by the Northwest Power Act to make cash payments is section 7(b) in conjunction with the REP established in section 5(c). WPAG Ex. Brief, WP-02-R-WA-01, at 7. The implementation of the traditional REP, however, uses a section 7(b) rate, the PF Exchange rate, which is compared with the utility's ASC and then multiplied by the utility's eligible residential load to produce REP benefits, which have traditionally been monetary, but which can be comprised of actual power sales. 16 U.S.C. §839c(c); 16 U.S.C. §839c(c)(5). WPAG is incorrect in its underlying assumption that the section 7(b) rate itself authorizes cash payments. It does not. The *REP* authorizes cash payments based on the comparison ASC and the PF Exchange rate. WPAG ignores another manner in which BPA can make monetary payments under the Bonneville Project Act and the Northwest Power Act. Section 2(f) of the Bonneville Project Act provides:

> Subject only to the provisions of this chapter, the Administrator is authorized to enter into such contracts, agreements, and arrangements, including the amendment, modification, adjustment, or cancellation thereof and the compromise or final settlement of any claim arising thereunder, *and to make such expenditures, upon such terms and conditions and in such manner as [she] may deem necessary*.

16 U.S.C. §832a(f) (emphasis added). This authority was reaffirmed in section 9(a) of the Northwest Power Act. 16 U.S.C. §839f(a). It is clear that the Administrator can make expenditures for settlements in such manner as she deems necessary, including the comparison of two endpoints--the five-year flat-block market forecast of power and the RL rate--to calculate monetary benefits for the IOU settlements.

WPAG argues that the RL rate contains a provision under which the purchaser receives a cash payment equal to the difference between the market price of power and the rate under which it is buying power from BPA. WPAG Brief, WP-02-B-WA-01, at 8. WPAG argues that the rate directives in section 7 do not grant BPA the authority to establish a cash payment program for customers as part of a requirements power rate. *Id.* WPAG argues that designating the Residential Exchange settlements as settlements does not permit institution of a cash payment program under the auspices of a requirements rate. *Id.* WPAG misunderstands the RL rate. The RL rate does not contain a provision under which the purchaser receives a cash payment equal to the difference between the market price of power and the rate under which it is buying power from BPA. *See* Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 30-34. While WPAG argues that the rate directives in section 7 do not grant BPA the authority to establish a cash payment program for customers as part of a requirements power rate, BPA has not established a cash payment program for customers in the RL rate. BPA's Subscription Strategy proposes a settlement of the REP with regional IOUs in which residential and small farm loads of the IOUs will be assured access to the equivalent of 1,800 [1,900] aMW of Federal power for the FY 2002-2006 period (and 2,200 aMW for the FY 2007-2011 period). Leathley *et al.*, WP-02-E-BPA-19, at 16. Of this amount, at least 1,000 aMW will be met with actual power deliveries. *Id.* The remaining 800 [900] aMW will be provided in the form of either power or monetary benefits, depending on which approach is most cost-effective for BPA. *Id.* This determination, as well as the amount of power and monetary benefits offered to each IOU, will be made in a separate process. *Id.* The monetary benefits will be based on the difference between the five-year flat-block market price of power forecasted in the rate case and the rate used to make Subscription sales to the IOUs (the RL-02 or the PF Exchange Subscription rate). *Id.*

Therefore, BPA's proposed settlements, if executed, will establish the monetary payment program as an element of that settlement, not the RL rate. BPA is not permitting institution of a cash payment program under the auspices of a requirements rate. The calculation of monetary benefits for a settlement must be based on some standard. Using the difference between the five-year flat-block market price of power forecasted in the rate case and the rate used to make Subscription sales to the IOUs, as provided in the Subscription Strategy, is a reasonable method for determining the monetary element of the settlement. The fact that the RL rate is a reference point in calculating such benefits does not mean that the RL rate establishes such a program.

WPAG admits that section 2(f) of the Bonneville Project Act provides BPA the authority to settle claims. WPAG Brief, WP-02-B-WA-01, at 8. WPAG argues that this authority does not establish authority to create rates for requirements service that contravene the rate directives of section 7(f) of the Northwest Power Act. *Id.* WPAG argues that this is particularly the case when the record is devoid of any outstanding claim between BPA and the customers to whom it is offering the RL rate. *Id.* Section 2(f) of the Bonneville Project Act provides:

> Subject only to the provisions of this chapter, the Administrator is authorized to enter into such contracts, agreements, and arrangements, including the amendment, modification, adjustment, or cancellation thereof and the compromise or final settlement of any claim arising thereunder, and to make such expenditures, upon such terms and conditions and in such manner as [she] may deem necessary.

16 U.S.C. §832a(f).

This provision grants broad discretion to the Administrator in the settlement of claims. This authority was affirmed in section 9(a) of the Northwest Power Act. 16 U.S.C. §839f(a). *See Utility Reform Project v. Bonneville Power Admin.*, 869 F.2d 437, 442-443 (9th Cir. 1989). This authority supports BPA's proposed Subscription settlements with the IOUs. However, BPA is not simply relying on this authority for the establishment of the RL rate or to establish any rate, much less a rate that would contravene the rate directives of section 7 of the Northwest Power Act. The RL rate, as discussed above, is consistent with the rate directives and legislative history of the Northwest Power Act. While WPAG argues that the record is devoid of any outstanding claim between BPA and the customers to whom it is offering the RL rate, this is incorrect. The outstanding claim is the prospective implementation of the REP under RPSAs during the coming rate and contract periods. Regional utilities have a right to participate in the REP. 16 U.S.C. §839c(c)(1). BPA previously explained the reasons supporting previous settlements of the REP, which also apply to settlements of the implementation of the program in the next rate period. *See* Leathley *et al.*, WP-02-E-BPA-19.

WPAG argues that assuming, *arguendo*, that BPA has the authority to establish the RL rate, BPA is offering the rate in an arbitrary and discriminatory fashion because it is being offered only to IOUs and not to preference customers that participate in the REP. WPAG Brief, WP-02-B-WA-01, at 9. As noted in the extensive preceding discussion in this ROD regarding the development of the RL rate, it clearly has not been developed in an arbitrary fashion. *See* Leathley *et al*., WP-02-E-BPA-19, at 8-14; Doubleday *et al*., WP-02-E-BPA-18, at 14-18; Doubleday *et al*., WP-02-E-BPA-44, at 5-9. With regard to the argument that the rate is being offered in an arbitrary fashion, BPA also disagrees. BPA's reasons for developing and offering IOU settlement power at the RL rate date back to BPA's Subscription Strategy. *See* Subscription Strategy, at 8-10, 16-17. One of the goals of the Subscription Strategy was to "spread the benefits of the FCRPS as broadly as possible with special attention given to residential and rural customers of the region." Subscription Strategy, at 3. One manner in which this was achieved was BPA's proposed settlement of the REP with the IOUs. *Id*. at 8-10. Additional support for offering power at the RL rate to the IOUs is presented in this ROD at great length. *See, e.g.*, Leathley *et al*., WP-02-E-BPA-19, at 8-14. In summary, the RL rate is not being offered in an arbitrary fashion. With regard to the argument that the RL rate is discriminatory, BPA disagrees. Reasons supporting the offer of the REP settlement to regional IOUs are discussed elsewhere. *See, e.g.*, Leathley *et al*., WP-02-E-BPA-19, at 8-14. In any event, however, the courts have recognized that BPA's rate directives do not establish a non-discrimination requirement. *Southern California Edison Co. v. Jura*, 909 F.2d 339, 343-344 (9th Cir. 1990) (challenging BPA's nonfirm energy rates under section 7(k) of the Northwest Power Act). With regard to the argument that the RL rate is being offered in a discriminatory manner, BPA disagrees. The RL rate is a rate developed under section 7(f) of the Northwest Power Act. 16 U.S.C. §839e(f). The rates for requirements service for IOUs are different than the rates for requirements service for BPA's preference customers. Compare 16 U.S.C. §839e(b)(1) with 16 U.S.C. §839e(f). BPA is not offering the RL rate in a discriminatory manner: BPA, under law, can only offer requirements power to the IOUs at a rate established under section 7(f) of the Northwest Power Act, the RL rate, and not to preference customers, who must, under section 7(b)(1) of the Northwest Power Act, pay the PF rate for requirements service. Indeed, preference customers do not need to purchase power at the RL rate, because they can purchase the exact same product at the exact same price (although under a different rate) by making such purchases at the PF rate.

The PPC notes that the exchange settlements are proposed to be offered to regional IOUs, but have not been proposed to be offered to other regional utilities participating in the REP. PPC Brief, WP-02-B-PP-01, at 64. WPAG argues that this is troublesome, because some IOUs eligible for the RL rate have sold or may sell all of their non-Federal generating resources that were previously used to serve their retail load. WPAG Brief, WP-02-B-WA-01, at 9. (A discussion of this issue is contained in ROD section 14.3.) As noted elsewhere in this ROD, BPA spent years with its customers and other interested parties developing BPA's Subscription Strategy. One element of this Strategy was the proposal of a settlement of the REP with regional IOUs. The Subscription Strategy did not address a proposed settlement of the REP with regional preference customers. The fact that BPA is proposing to offer a particular exchange settlement to the IOUs, however, does not mean that BPA will not offer an exchange settlement to BPA's exchanging preference customers. BPA has not yet completed discussions of potential exchange settlements with its exchanging preference customers, but BPA has not precluded doing so. Because those discussions have not yet concluded, it is not known whether the form of such settlements would be similar to that proposed for the IOUs or an approach that might better reflect the particular characteristics of preference utilities. Furthermore, BPA's rate case is to establish rates, not to determine whether BPA should offer a new exchange settlement to a particular customer class.

In any event, however, BPA is not required to offer the same settlement to all of BPA's customers. As noted above, section 2(f) of the Bonneville Project Act provides that the Administrator may enter into settlements "upon such terms and in such manner as [she] may deem necessary." 16 U.S.C. §832a(f). *See Utility Reform Project v. Bonneville Power Admin.*, 869 F.2d 437, 442-443 (9th Cir. 1989). It is appropriate to consider settlement proposals for different classes of BPA's customers. BPA's IOU customers differ from BPA's preference customers in many ways. For example, IOUs are for-profit companies, while preference customers are generally non-profit. IOUs are regulated by state utility commissions, while preference customers generally make decisions through their boards. IOUs do not have preference and priority to Federal power, while preference customers have such priority. IOUs have been the primary recipients of benefits under the REP, while preference customer benefits have been much smaller. In addition, numerous preference customers have already settled the REP through 2011 and do not require a settlement at this time. For many reasons, it is appropriate to offer the proposed settlement only to regional IOUs at this time.

WPAG argues that while BPA stated that it is proper to limit the RL rate to IOUs since settlement discussions with preference customers participating in the REP have not been completed, in fact no such discussions have been initiated and there is no evidence in the record that BPA intends to initiate settlement discussions with preference customers. WPAG Ex. Brief, WP-02-R-WA-01, at 8-9. WPAG argues that BPA's failure to initiate settlement discussions with preference customers is not a legal justification for excluding preference customers from the settlement proposed for the IOUs. *Id*. In response to these arguments, as noted previously, it is proper to limit the RL rate to IOUs because, under law, only IOUs may purchase requirements power from BPA under section 7(f) of the Northwest Power Act. In addition, the fact that BPA is proposing to offer a particular exchange settlement to the IOUs does not mean that BPA will not offer an exchange settlement to BPA's exchanging preference customers. BPA noted that it had not completed discussions of potential exchange settlements with exchanging preference customers but has not precluded doing so. BPA did not mean to imply that such negotiations were currently underway with preference customers, but rather that BPA expected to have such discussions and such discussions have not yet occurred, or been completed. The issue, therefore, is not an issue of discrimination. It is simply an issue of timing. It should be noted, however, that while WPAG states that BPA has not initiated settlement discussions with its preference customers, BPA does not recall a request from WPAG to initiate settlement discussions with BPA. Settlement discussions can be initiated by either party. While WPAG claims that there is no evidence in the record that BPA intends to initiate discussions with preference customers, BPA did discuss some of the standards for the REP and the REP settlements in the context of both IOU and preference customers during the hearing. Tr. 1556-68. Settlements of the REP, however, do not have to be done at the same time or in the same manner for all exchanging utilities. Indeed, BPA's testimony noted that BPA had negotiated settlements of the REP with all but one utility. Leathley *et al*., WP-02-E-BPA-19, at 10-11. This includes IOUs and preference customers. BPA issued records of decision for REP settlements. Each settlement occurred with an individual utility or a group of utilities represented by an organization, such as the settlement agreement BPA executed with PNGC and nine PNGC members. The fact that BPA offered a settlement agreement to one utility or a group of utilities did not require BPA, in over 30 settlement agreements that BPA executed, to offer the same settlement to all other exchanging utilities. There are two classes of exchanging utilities--exchanging IOUs and exchanging preference customers. The settlements for such utilities need not be the same as offered to members of the other class. Therefore, contrary to WPAG's claim, BPA's settlement proposal to regional IOUs is not discriminatory, and certainly not unduly discriminatory, even though it is not currently offered to BPA's preference customers.

Decision

BPA properly developed the RL rate. BPA intends to acquire approximately 1,282 aMW of power purchases as FBS replacements.

12.4 Allocation of 7(b)(2) Amount

Issue

Whether BPA properly allocated the 7(b)(2) rate test trigger amount.

Parties' Positions

WPAG argues that BPA did not follow the statutory directive that requires that the trigger amount be allocated to all other rates under which power is sold by BPA. WPAG Brief, WP-02-B-WA-01, at 10-11; WPAG Ex. Brief, WP-02-R-WA-01, at 10-15. The PPC and OURCA argue that BPA should assign the costs identified through the section 7(b)(2) rate test to the forecasted load of the RL class. PPC Ex. Brief, WP-02-R-PP-01, at 16; OURCA Ex. Brief, WP-02-R-OU-01, at 8.

BPA's Position

BPA properly allocated the section 7(b)(2) trigger amount. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 63-65.

Evaluation of Positions

WPAG argues that section 7(b)(3) of the Northwest Power Act requires that the 7(b)(2) trigger amount be "recovered through supplemental rate charges for all other power sold by the Administrator to all other customers." WPAG Brief, WP-02-B-WA-01, at 10, WPAG Ex. Brief, WP-02-R-WA-01, at 10-11. WPAG argues that the trigger amount was allocated only to the PF Exchange, NR, and IP rates, and since BPA is forecasting that there will be no loads served under these rates during the rate period, the trigger amount ends up back in the PF rate. *Id.* WPAG argues that this deprives preference customers of the cost protection that the rate test was intended to provide them. *Id.* WPAG argues that proper allocation of the trigger amount would increase the RL rate. *Id.* WPAG argues that the trigger amount should be allocated to all power rates under which BPA intends to sell power to the IOUs and DSIs. *Id.*

First, WPAG and OURCA argue that the trigger amount was allocated only to the PF Exchange, NR, and IP rates, and BPA is forecasting that there will be no loads served under these rates during the rate period. WPAG Brief, WP-02-B-WA-01, at 10; OURCA Ex. Brief, WP-02-R-OU-01, at 8. This argument is incorrect. In this rate case, BPA does not know the manner in which IOUs will purchase power or receive Federal benefits from BPA. Leathley *et al*., WP-02-E-BPA-19, at 12. IOUs may continue the REP or participate in settlements of that program. The Rate Design Step reflects the circumstance where the IOUs participate in the REP. In this case, the Rate Design Step properly allocated the trigger amount to all other rates in that Step. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 72. This includes about 1,300 aMW of Residential Exchange load and 990 aMW of DSI load, and also NR load. BPA is not stating that no sales are forecasted for these loads. Instead, in the Rate Design Step, where the 7(b)(2) rate test is calculated, those loads are forecasted to occur. In addition, however, BPA must recognize the possibility that IOUs would execute the proposed settlement agreements. The record shows that the forecasted cost of the proposed settlements exceeds the forecasted net cost of the REP in the Rate Design Step. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, Table SUBSCR.01, lines 19 and 24. BPA must establish rates to recover its costs. Because BPA does not know which option the IOUs will pick, however, BPA must assume the highest-cost possibility in setting rates in order to ensure the recovery of its costs. Therefore, the development of rates based on costs in the Subscription Step does not mean that BPA is not forecasting loads to occur in the Rate Design Step. Further, costs are allocated to the other loads in the Rate Design Step.

WPAG argues that the trigger amount should be allocated to all power rates under which BPA intends to sell power to the IOUs and DSIs. WPAG Brief, WP-02-B-WA-01, at 10. The PPC and OURCA argue that BPA should assign the cost identified through the section 7(b)(2) rate test to the forecasted load of the RL class. PPC Ex. Brief, WP-02-R-PP-01, at 16; OURCA Ex. Brief, WP-02-R-OU-01, at 8. WPAG, OURCA and the PPC argue that the practical effect of shielding the Subscription Step rates from their appropriate share of the rate test trigger amount is to shift such costs back to the PF rate, thereby depriving the preference customers of the cost protection that the rate test was intended to provide. WPAG Ex. Brief, WP-02-R-WA-01, at 11; OURCA Ex. Brief, WP-02-R-OU-01, at 8; PPC Ex. Brief, WP-02-R-PP-01, at 15. Given that BPA must develop rates to reflect two mutually exclusive scenarios in which IOUs may receive benefits from the Federal system, it is inappropriate that such amount be allocated to the RL and PF Exchange Subscription rates. As noted above, in the Rate Design Step of the RAM, the modeling assumes the full implementation of the traditional REP. Doubleday *et al*., WP-02-E-BPA-18, at 15-16. The rate that is applicable to the traditional REP is the PF Exchange Program rate. Tr. 2277-78. Before the 7(b)(2) rate test is performed in the Rate Design Step, the PF Exchange Program rate and the PF Preference rate are equal, and are, in fact, one unbifurcated PF rate. *Id.* If the 7(b)(2) rate test triggers, an amount of PF Preference rate protection is calculated and allocated to all other rates, resulting in the bifurcation of the PF rate into the PF Exchange Program rate and the PF Preference rate. *Id.* The traditional REP is assumed in only the Rate Design Step. The PF Exchange Program rate is applicable in only the Rate Design Step. Therefore, the 7(b)(2) rate test used to determine the PF Exchange Program rate used in the implementation of the traditional REP is applicable to only the Rate Design Step. It also follows that rates not associated with the Rate Design Step, such as the RL and PF Exchange Subscription rates, would not be involved in the allocation of PF rate protection amounts calculated in the Rate Design Step. The PF rate protection amount is already fully allocated in the Rate Design Step before implementation of the Subscription Step in the RAM, where the RL, PF Exchange Subscription, and IP/IPTAC rates are calculated. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 72. In addition, the IP Indexed rate is not modeled in the RAM, with the assumption that the IP Indexed rate will recover the same revenues as the IP/IPTAC rate over the rate period. Miller *et al*., WP-02-E-BPA-21, at 3.

It is inappropriate to allocate the trigger amount to the RL and PF Exchange Subscription rates for additional reasons. This requires a review of section 7(b)(3) of the Northwest Power Act. 16 U.S.C. §839e(b)(3). Section 7(b)(3) of the Northwest Power Act provides:

> Any amounts not charged to public body, cooperative, and Federal agency customers by reason of paragraph (2) of this subsection *shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers*. Rates charged public body, cooperative, or Federal agency customers pursuant to this subsection shall not include any costs or benefits of a net revenue surplus or deficiency occurring for the period ending June 30, 1985, to the extent such surplus or deficiency is caused by a difference between actual power deliveries and power deliveries projected for the purpose of establishing rates to direct service industrial customers under subsection (c)(1) of this subsection, and an overrecovery or underrecovery of the net costs incurred by the Administrator under section 5(c) as a result of such difference.
>
> Any such revenue surplus or deficiency incurred *shall be recovered from, or repaid to, customers over a reasonable period of time after July 1, 1985, through a supplemental rate charge or credit applied proportionately for all other power*

> *sold by the Administrator* at rates established under other subsections of this section prior to July 1, 1985.

16 U.S.C. §839e(b)(3) (emphasis added).

It is important to recognize the distinction drawn by Congress regarding the allocation of the costs under section 7(b)(3). For allocations of a net revenue surplus or deficiency under section 7(b)(3), such amounts are "recovered from, or repaid to, customers over a reasonable period of time after July 1, 1985, through a supplemental rate charge or credit applied proportionately for all other power sold by the Administrator." In other words, Congress knew how to provide for proportional allocations of the referenced costs and expressly did so. For general allocations of the 7(b)(2) trigger amount, however, Congress did not require a proportional allocation, but rather provided that such amounts are recovered through "supplemental rate charges for all other power sold by the Administrator to all customers." This means that BPA is not required to proportionally allocate the trigger amount to all other power sold by the Administrator to all customers. Nevertheless, BPA generally believes that such a proportional allocation is the appropriate means to allocate the trigger amount to BPA's power sales to non-preference customers.

As noted previously, BPA is facing special circumstances in the current rate case. BPA does not know the manner in which IOUs will purchase power or receive benefits from the Federal system, whether through the REP or through the proposed exchange settlements with IOUs. The principles for the proposed exchange settlements were developed in BPA's Subscription Strategy in order to establish an appropriate value to be provided by BPA (a minimum of 1,000 aMW of power at a rate expected to be approximately equivalent to the PF Preference rate and 800 [900] aMW in financial benefits) for the value provided by the IOUs (settlement of the REP). These settlements have not yet been offered or executed, and BPA must use the information available at this time in developing rates. The RL and PF Exchange Subscription rates are special rates used solely for the purpose of implementing proposed settlements of the REP. As noted above, it is inappropriate to allocate the trigger amount to these rates, because of the special circumstances and manner in which BPA had to develop rates in this proceeding (*see* previous discussion of Rate Design Step and Subscription Step). In addition, however, as noted above, BPA is not required to allocate the trigger amount on a proportional basis. This means that the amounts allocated to particular settlement sales may vary among the power sales to BPA's non-preference customers. Given the special nature of the RL and PF Exchange Subscription rates and that their use is strictly limited to proposed settlement sales, and that their proposed level is the appropriate level to establish the proper consideration for the settlement of the REP, it is appropriate that additional costs not be allocated to those rates. BPA emphasizes that this is a special circumstance and an exception to BPA's usual allocation of such amounts.

WPAG argues that the use of the word "proportionately" in the last sentence of section 7(b)(3) in conjunction with an unrelated credit or charge does not alter the language establishing the duty of the Administrator to spread to all other power sold to all customers the costs that must be excluded from the PF rate due to the rate test. WPAG Ex. Brief, WP-02-R-WA-01, at 14. WPAG goes on to argue that even assuming, *arguendo*, that BPA may not be statutorily required to allocate the rate test trigger proportionately to all non-preference rates, and may have the freedom to choose how much is allocated to each of the rates other than the PF rate, this does not free BPA to make such allocation decisions in a manner that results in the preference customers paying any portion of the rate test trigger amount. *Id.* BPA disagrees with WPAG's allegation that the preference customers pay a portion of the rate test trigger amount. The current rate case is unique in that BPA must establish appropriate rates to be used in the traditional REP, as well as rates to be used in the event of a settlement of the REP. Doubleday *et al*., WP-02-E-BPA-18, at 16. To accommodate this unique situation, BPA's ratemaking process includes two rate modeling steps, a Rate Design Step and a Subscription Step. *Id*. at 14-20. The Rate Design Step produces rates that are appropriate for a world that includes the traditional REP. *Id*.

BPA conducts the section 7(b)(2) rate test in the Rate Design Step of the rates models. This is appropriate for a number of reasons. First, section 7(b)(2) of the Northwest Power Act provides that the absence of the traditional REP is one of the five section 7(b)(2) assumptions. 16 U.S.C. §839e(b)(2). Therefore, the section 7(b)(2) rate test must be performed in the Rate Design Step that includes the traditional REP, because, under law, rates must be compared between the Program Case, where the program exists, and the 7(b)(2) Case, where the program does not exist. The Rate Design Step is the only step that models the traditional REP. Doubleday *et al*., WP-02-E-BPA-18, at 16. In addition, if the section 7(b)(2) rate test triggers, the PF Preference rate protection costs are allocated to other firm loads in the Rate Design Step, including the IP rate and PF Exchange Program rate loads. 16 U.S.C. §839e(b)(3). This results in a bifurcation of the PF rate into a PF Preference rate and a PF Exchange Program rate, which occurs only in the Rate Design Step. *Id*. Therefore, in the Rate Design Step, the amount of preference customer rate protection is both calculated and allocated to all other loads. In this case, the Rate Design Step has properly allocated the rate test trigger amount from the PF Preference customers to all other rates in that Step. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 72. While BPA must calculate the 7(b)(2) rate test in the Rate Design Step, where the amount of the 7(b)(2) trigger is indeed allocated to other power sales, BPA must also comply with the statutory requirement to recover its total costs. 16 U.S.C. 839e(a)(1). In the Subscription Step, BPA assumes that regional IOUs execute proposed settlements of the REP. BPA must therefore calculate Subscription Step rates that recover the costs of such settlements. Where such settlements would impose higher costs on BPA, BPA must allocate such costs to rates. Doubleday *et al*., WP-02-E-BPA-18, at 17-18; Doubleday *et al*., WP-02-E-BPA-44, at 13. It would be inappropriate, however, to conduct the 7(b)(2) rate test in the Subscription Step, because one of the five section 7(b)(2) assumptions, the traditional REP, does not exist in the Subscription Step.

WPAG argues that the structure of the settlement proposed for the IOUs requires BPA to elect whether to allocate the rate test trigger amount to either the NR and PF Exchange Program rates, or the RL, PF Exchange Subscription and IP/IPTAC rates. WPAG Ex. Brief, WP-02-R-WA-02, at 11-12. BPA disagrees with WPAG's argument that BPA has a choice as to which set of rates the rate test trigger amount can be allocated. As stated above, the section 7(b)(2) rate test must be performed in the Rate Design Step, which includes the traditional REP, because, under law, rates must be compared between the Program Case, where the program exists, and the 7(b)(2) Case, where the program does not exist. The Rate Design Step is the only step that models the traditional REP. In addition, if the section 7(b)(2) rate test triggers, the PF Preference rate protection costs are allocated to other firm loads in the Rate Design Step, including the IP rate and PF Exchange Program rate loads. 16 U.S.C. §839e(b)(3). This results in a bifurcation of the PF rate into a PF Preference rate and a PF Exchange Program rate, which occurs only in the Rate Design Step. Therefore, in the Rate Design Step, the amount of preference customer rate protection is both calculated and allocated to all other loads. In this case, the Rate Design Step has properly allocated the rate test trigger amount from the PF Preference customers to all other rates in that Step. Those Rate Design Step rates are the IP, NR, and PF Exchange Program rates. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 72.

WPAG argues that the fact that BPA has placed itself in an untenable position in its negotiations with the IOUs over the REP and the purported settlement does not absolve BPA of its responsibility to adhere to the requirements of sections 7(b)(2) and (3) of the Northwest Power Act, nor to provide its preference customers with the rate protection guaranteed to them by these statutory provisions. WPAG Ex. Brief, WP-02-R-WA-02, at 12. First, BPA has not placed itself in an untenable position in its negotiations with the IOUs. The principles of BPA's proposed IOU settlements were developed in the extensive public process used to develop BPA's Subscription Strategy. BPA's settlement proposal provides appropriate consideration, developed in a logical, consistent and lawful manner, in exchange for the rights of the IOUs to participate in the REP. Furthermore, BPA disagrees with WPAG's argument that BPA is not adhering to the requirements of sections 7(b)(2) and (3) of the Northwest Power Act. The section 7(b)(2) rate test is a statutorily required component of BPA's ratemaking process. The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements loads of BPA's public body, cooperative, and Federal agency customers (7(b)(2) or preference customers). The two sets of rates are: (1) a set for the rate filing test period (FY 2002-2006) and the ensuing four years (FY 2007-2010) assuming that section 7(b)(2) is not in effect (Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) Case rates). The 7(b)(2) Case rates are modeled exactly the same as the Program Case rates except for the five assumptions listed in section 7(b)(2). The five assumptions prescribed by section 7(b)(2) of the Northwest Power Act and used to model the 7(b)(2) Case are:

(1) Within or adjacent DSI loads are transferred to public utilities at the start of the 7(b)(2) rate test period; the remaining DSI loads are transferred to IOUs as BPA/DSI pre-Northwest Power Act contracts expire.

(2) *No section 5(c) REP takes place.*

(3) Additional resources of three specified types serve the loads of 7(b)(2) customers when FBS resources are exhausted.

(4) The DSI reserve benefits under provisions of the Northwest Power Act are not available in the 7(b)(2) Case. The 7(b)(2) Case rates will reflect this increased cost to the 7(b)(2) customers.

(5) Financing benefits under provisions of the Northwest Power Act are not available in the 7(b)(2) Case. The 7(b)(2) Case rates will reflect this increased resource

> cost due to the absence of BPA financial backing if additional resources are required to serve 7(b)(2) customers.

See 16 U.S.C. §839e(b)(2) (emphasis added). For a discussion of the development of the Program and 7(b)(2) Case rates, *see* Section 7(b)(2) Rate Test Study, WP-02-FS-BPA-06, and Section 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A.

The current rate case is unique in that BPA must establish appropriate rates to be used in the traditional REP, as well as rates to be used in the event of a settlement of the REP. Doubleday *et al*., WP-02-E-BPA-18, at 16. To accommodate this unique situation, BPA's ratemaking process includes two rate modeling steps, a Rate Design Step and a Subscription Step. *Id*. at 14-20. The Rate Design Step produces rates that are appropriate for a world that includes the traditional REP. *Id*. The Subscription Step produces rates that are appropriate for a world where the traditional REP does not exist, and has been replaced with a settlement agreement. *Id*.

BPA conducts the section 7(b)(2) rate test in the Rate Design Step of the rates models. As noted previously, this is appropriate for a number of reasons. First, section 7(b)(2) of the Northwest Power Act provides that the absence of the traditional REP is one of the five section 7(b)(2) assumptions. Therefore, the section 7(b)(2) rate test must be performed in the rate design step that includes the traditional REP, because, under law, rates must be compared between the Program Case, where the program exists, and the 7(b)(2) Case, where the program does not exist. The Rate Design Step is the only step that models the traditional REP. In addition, if the section 7(b)(2) rate test triggers, the PF Preference rate protection costs are allocated to other firm loads in the Rate Design Step, including the IP rate and PF Exchange Program rate. 16 U.S.C. §839e(b)(3). This results in a bifurcation of the PF rate into a PF Preference rate and a PF Exchange Program rate, which occurs only in the Rate Design Step. While BPA must calculate the 7(b)(2) rate test in the Rate Design Step, where the amount of the 7(b)(2) trigger is allocated to other power sales, BPA must also comply with the statutory requirement to recover its total costs. 16 U.S.C. §839e(a)(1). In the Subscription Step, BPA assumes that regional IOUs execute proposed settlements of the REP. BPA must therefore calculate Subscription Step rates that recover the costs of such settlements. Where such settlements would impose higher costs on BPA, BPA must allocate such costs to rates. Doubleday *et al*., WP-02-E-BPA-18, at 17-18; Doubleday *et al*., WP-02-E-BPA-44, at 13. It would be inappropriate, however, to conduct the 7(b)(2) rate test in the Subscription Step, because one of the five section 7(b)(2) assumptions, the traditional REP, does not exist in the Subscription Step.

WPAG argues that the proposed DSI Compromise demonstrates that BPA has the ability to require customers being offered a settlement to choose between two mutually exclusive options before the start of this proceeding. WPAG Ex. Brief, WP-02-R-WA-02, at 12. BPA disagrees with the WPAG argument that the DSI Compromise approach is analogous to the IOU REP settlement. While both the DSI Compromise and the REP settlements require that a choice be made between two mutually exclusive options, the timing of when the choices must be made is quite different. BPA's power sales to the DSIs for the coming rate period were unclear and had to be addressed in some manner before BPA could forecast DSI loads and conduct the power rate case. The DSI Compromise Approach is a way of determining how much BPA power DSIs will be qualified to purchase, and at what proposed price. BPA proposed that the total amount of power would be allocated according to the relative amounts of IP-96 purchases of each eligible DSI. Berwager *et al.,* WP-02-E-BPA-09, at 7-8. In other words, those DSIs that purchased larger amounts of power from BPA during the current rate period would be entitled to a larger proportional share of the available power than DSIs that placed less load on BPA at the IP-96 rate during this period. *Id.* Further, only those DSIs that were willing to support the Compromise Approach proposal in the rate case and in other forums would be eligible to purchase power at the proposed Compromise Approach rate of 23.5 mills/kWh. *Id.* The slightly higher rate of 25.0 mills/kWh under the Targeted Augmentation Approach would be available to DSIs that were unwilling to commit to supporting the Compromise Approach as proposed in BPA's initial proposal. *Id.* Therefore, individual DSIs had to choose whether to support the Compromise Approach or not before the rate case proceeding.

In contrast to the Compromise Approach, the proposed IOU REP settlements require the IOUs to choose between the benefits offered under the traditional REP and the benefits offered under the settlement. BPA's Subscription Strategy proposes a settlement of the REP with regional IOUs in which residential and small farm loads of the IOUs will be assured access to the equivalent of 1,800 [1,900] aMW of Federal power for the FY 2002-2006 period (and 2,200 aMW for the FY 2007-2011 period). Leathley *et al.*, WP-02-E-BPA-19, at 16. Of this amount, at least 1,000 aMW will be met with actual power deliveries. *Id.* The remaining 800 [900] aMW will be provided in the form of either power or monetary benefits depending on which approach is most cost-effective for BPA. *Id.* This determination, as well as the amount of power and monetary benefits offered to each IOU, will be made in a separate process. *Id.* The monetary benefits will be based on the difference between the five-year flat-block market price of power forecasted in the rate case and the rate used to make Subscription sales to the IOUs (the RL-02 or the PF Exchange Subscription rate). *Id.* The benefits of the traditional REP are determined, in part, by the level of the PF Exchange Program rate. The PF Exchange Program rate is calculated in the rate case and will not be known until the final rate case documents are published. Clearly, the IOUs cannot make an informed decision between the traditional REP, to which they have a statutory right, and the settlement before the value of the benefits associated with the traditional REP has been forecasted at the conclusion of the rate case.

WPAG argues that the fact that BPA did not require the IOUs to make an election between the traditional REP and a settlement prior to the start of this proceeding does not in any manner free BPA of its duty to implement the provisions of the rate test. WPAG Ex. Brief, WP-02-R-WA-01, at 12. As noted above, it would have been inappropriate for BPA to require the IOUs to make an election between the traditional REP and a settlement prior to the start of this proceeding. In addition, however, BPA must address the circumstances that it could face in the coming rate period in order to ensure that it recovers its total costs. These include the continuation of the traditional REP, on one hand, and the proposed settlements of the REP, on the other hand. BPA cannot simply ignore circumstances that may affect BPA's total costs. Furthermore, BPA has implemented the provisions of the rate test properly and allocated the rate test trigger amount to the appropriate non-preference rates. As noted above, the section 7(b)(2) rate test must be performed in the Rate Design Step, which includes the traditional REP, because, under law, rates must be compared between the Program Case, where the program exists, and the 7(b)(2) Case, where the program does not exist. The Rate Design Step is the only step that models the traditional REP. In addition, if the section 7(b)(2) rate test triggers, the PF Preference rate protection costs are allocated to other firm loads in the Rate Design Step, including the IP rate and PF Exchange Program rate. 16 U.S.C. §839e(b)(3).

WPAG argues that BPA should allocate to the rates formulated in the Rate Design Step (the PF Exchange Program and NR rates) and those formulated at the Subscription Step (the RL, PF Exchange Subscription, and the IP/IPTAC rates) the full portion of the rate test trigger amount. WPAG Ex. Brief, WP-02-R-WA-01, at 12. WPAG also argues that since each IOU must choose whether to participate in the REP or in the settlement proposal, and cannot do both, such an allocation would not result in an over-collection of BPA's costs. *Id.* at 13. WPAG argues that such an allocation scheme would result in BPA complying with the requirements of the rate test by allocating the rate test trigger amount to all other power purchased by all other customers, and proving that preference customers receive the full cost protection to which they are entitled under sections 7(b)(2) and (3) of the Northwest Power Act. *Id.* at 13. WPAG's new allocation proposal was not raised during the hearing, and BPA and the rate case parties have not had an opportunity to review this proposal. Based on WPAG's argument, however, this proposal is inappropriate and an insufficient substitute for BPA's proposal. As noted above, BPA conducts the section 7(b)(2) rate test in the Rate Design Step of the rates models. This is appropriate for a number of reasons. First, section 7(b)(2) of the Northwest Power Act provides that the absence of the traditional REP is one of the five section 7(b)(2) assumptions. Therefore, the section 7(b)(2) rate test must be performed in the Rate Design Step, which includes the traditional REP, because, under law, rates must be compared between the Program Case, where the program exists, and the 7(b)(2) Case, where the program does not exist. The Rate Design Step is the only step that models the traditional REP. In addition, if the section 7(b)(2) rate test triggers, the PF Preference rate protection costs are allocated only to other firm loads in the Rate Design Step, including the IP rate and PF Exchange Program rate. 16 U.S.C. §839e(b)(3). BPA's ratemaking process allocates costs to customer loads in sequential steps starting with the initial COSA allocations and continuing through the various statutory rate design adjustments, including the 7(c)(2) and 7(b)(2) rate design adjustments. In each step of the ratemaking process, specific cost amounts are allocated to specific customer loads, and a balancing credit amount is allocated to other customer loads. *See* Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A, Table RDS40. Each adjustment of costs between rate classes merely redistributes the original revenue requirement amount among the customer classes. A ratemaking adjustment cannot, as WPAG suggests, allocate twice the amount of costs to some loads as it credits to other loads. Allocating the entire rate test trigger amount twice to two different customer loads, one in the Rate Design Step and the other in the Subscription Step, does not comport with BPA's ratemaking methods. In addition, as stated above, the 7(b)(2) rate test is appropriate only for the Rate Design Step, and the allocation of the 7(b)(2) rate test trigger amount should be to only those loads used in the calculation of the 7(b)(2) rate test trigger.

WPAG argues that the fact that BPA has added a new and heretofore unheard of "Subscription Step" to its rate process does not relieve BPA of the statutory duty to allocate to all other power sold to all other customers, including customers purchasing power under the RL, PF Exchange Subscription, and IP/IPTAC rates, the costs that must be excluded from the PF rate under the terms of the rate test. WPAG Ex. Brief, WP-02-R-WA-01, at 13. BPA has not argued that adding the Subscription Step relieves BPA from its statutory duties. Instead, it is a means of implementing BPA's statutory duties. As BPA explained previously in section 12.2 regarding

BPA's implementation of the Rate Design Step and the Subscription Step, the fact that the Subscription Step is new does not mean that it is inappropriate or inconsistent with statute. WPAG argues that the statute does not exempt a rate from bearing its share of the rate test trigger amount based on when in the rate process it is formulated. *Id.* WPAG argues that the fact that the RL, PF Exchange Subscription, and IP/IPTAC rates were formulated in the Subscription Step, instead of the Rate Design Step, does not shield them from the statutory directive that they be allocated a portion of the rate test trigger amount. *Id.* at 13-14. As discussed at length above, the 7(b)(2) rate test is properly performed in the Rate Design Step of the RAM. Also as discussed above, the entire amount of the section 7(b)(2) rate test trigger rate protection amount is credited to the PF Preference rate, and those costs are allocated to other rates in the Rate Design Step of the RAM. Having afforded the PF Preference class rate protection in the Rate Design Step, it would be redundant to repeat that step again. Since the entire amount of the section 7(b)(2) rate test trigger PF Preference rate protection has been allocated to other rate classes before the calculation of the Subscription Step rates, it would be inappropriate to reallocate that very same PF Preference rate protection amount to those rates. This argument is discussed in additional detail below.

WPAG argues that by shielding the RL, PF Subscription, and IP/IPTAC rates from paying the rate test trigger amount, BPA has failed to fulfill its statutory duty, and has constructed a PF rate that includes costs that the rate test requires BPA to collect from all other power sold to all other customers. WPAG Ex. Brief, WP-02-R-WA-01, at 15. As discussed at length above, the 7(b)(2) rate test is properly performed in the Rate Design Step of the RAM. Also as discussed above, the entire amount of the section 7(b)(2) rate test trigger rate protection amount is credited to the PF Preference rate, and those costs are allocated to other rates in the Rate Design Step of the RAM. Having afforded the PF Preference class the section 7(b)(2) rate test trigger rate protection in the Rate Design Step, it would be redundant to repeat that step again. Since the entire amount of the section 7(b)(2) rate test trigger PF Preference rate protection has been allocated to other rate classes before the calculation of the Subscription Step rates, it would be inappropriate to reallocate that very same PF Preference rate protection amount to those rates. This issue has been addressed at great length in this section.

WPAG argues that while BPA may feel that implementation of its Subscription proposal presents special circumstances that warrant an abrogation of the statutory duty to allocate the rate test trigger amount to all other power sold to all other customers, neither the statute, nor the case law recognize such an exception. WPAG Ex. Brief, WP-02-R-WA-01, at 15. Contrary to WPAG's argument, BPA does not feel that special circumstances warrant an abrogation of the statutory duty to allocate the rate test trigger amount to all other power sold to all other customers. Instead, these special circumstances have been accommodated consistent with existing law, as explained in greater detail in this chapter. As explained previously at great length, BPA added a Subscription Step to its ratemaking process to accommodate the special circumstances it faces in the current rate case. However, BPA is abiding by sections 7(b)(2) and (3) of the Northwest Power Act. BPA conducts the section 7(b)(2) rate test in the Rate Design Step of the rates models. This is appropriate for a number of reasons. First, section 7(b)(2) of the Northwest Power Act provides that the absence of the traditional REP is one of the five section 7(b)(2) assumptions. Therefore, the section 7(b)(2) rate test must be performed in the Rate Design Step, which includes the traditional REP, because, under law, rates must be compared between the Program Case, where the program exists, and the 7(b)(2) Case, where the program does not exist. The Rate Design Step is the only step that models the traditional REP. In addition, if the section 7(b)(2) rate test triggers, the PF Preference rate protection costs are allocated to other firm loads in the Rate Design Step, including the IP rate and PF Exchange Program rate. 16 U.S.C. §839e(b)(3). In addition to these reasons, assuming, *arguendo*, that BPA must allocate the trigger amount to the RL, PF Exchange Subscription, and IP/IPTAC rates despite the inappropriateness of doing so, as noted previously, section 7(b)(3) of the Northwest Power Act provides BPA with discretion in the allocation of the trigger amount to non-preference sales. 16 U.S.C. §839e(b)(3). Because such allocation does not have to be proportional, BPA's allocations to particular rates may range from very little, including nothing, to very great. In the development of current rates, for example, BPA can allocate $1,000 to the rates that WPAG has alleged have escaped the allocation of the trigger amount: the RL, PF Exchange Subscription, and the IP/IPTAC rates. Such an allocation, however, does not change BPA's rates to preference customers or any other customer class and complies with WPAG's argument that such rates must be allocated some of the trigger amount. BPA has previously noted that, given the extraordinary circumstances BPA faces in developing rates in this proceeding and the fact that the RL and PF Exchange Subscription rates are *settlement* rates for a single limited purpose--to provide power sales at a rate that provides appropriate consideration for the settlement of the REP--BPA's cost allocations are properly conducted in order to establish rates that provide the proper consideration for the REP settlements. WPAG argues that BPA's desire to strike a political bargain with the IOUs to provide them with power at the same rate paid by preference customers, based on the dubious proposition that doing so will gain BPA political allies, simply does not override its duty to abide by sections 7(b)(2) and (3) of the Northwest Power Act. *Id.* First, there is no evidence in the record that BPA has struck a political bargain with the IOUs based on the proposition that doing so will gain BPA political allies. As evidenced by the record, some IOUs have been extremely critical of the proposed settlements and settlement rates, among other things. BPA is not concerned with whether BPA's proposal will gain BPA political allies. Instead, BPA is concerned with ensuring that it is developing its rates in a manner that complies with the rate directives of sections 7(b)(2) and 7(b)(3).

<u>Decision</u>

BPA properly allocated the 7(b)(2) amount.

13.0 SECTION 7(b)(2) RATE TEST

13.1 Introduction

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

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

The methodology to implement section 7(b)(2) was developed in a section 7(i) proceeding that preceded BPA's 1985 rate case. The section 7(i) process culminated in the Section 7(b)(2) Implementation Methodology ROD (Implementation ROD), b-2-84-F-02. Issues regarding interpretation of the statute were resolved in the Legal Interpretation for Section 7(b)(2), b-2-84-FR-03, 49 Fed. Reg. 23,998 (1984).

To understand the context of the development of BPA's rates and the implementation of the 7(b)(2) rate test, it is helpful to review the genesis of the REP and the rate protection afforded BPA's preference customers from potential excessive costs of that program.

BPA was established by the Bonneville Project Act of 1937 (Project Act), 16 U.S.C. §832 *et seq*. After enactment of the Project Act, BPA marketed the low cost hydropower generated by Federal dams in the PNW. While section 4(a) of the Project Act requires BPA to "give preference and priority to public bodies and cooperatives" when selling power, 16 U.S.C. §832c(a), BPA had sufficient power for many years to serve the needs of all customers in the region. These customers include public bodies and cooperatives, known as "preference customers" because of their statutory first right to Federal power under the preference clause noted above. *Id*. These customers also included IOUs and DSIs. In 1948, the increasing demand for power caused BPA to require that contracts with the DSIs must include provisions to allow the interruption of service when necessary to meet the needs of BPA's preference customers. H.R. Rep. No. 96-976, Part 2, at 28 (1980). In the 1970s, forecasts showed that preference customers soon would require all of BPA's power. *Id*. Therefore, in 1973, BPA gave notice that new contracts for firm power for IOUs would not be offered, and that as DSI contracts expired between 1981-1991, the contracts were not likely to be renewed. *Id*. at 29. In 1976, BPA advised preference customers that BPA would not be able to satisfy preference customer load growth after 1983, and would have to determine how to allocate power among preference customers. *Id*. at 30.

While Federal appropriations were used in the construction of the Federal hydrosystem, Federal taxpayers ultimately did not pay these costs. The costs of the hydrosystem are repaid with interest over time by BPA's ratepayers through BPA's wholesale power revenues. Thus, BPA's ratepayers are the parties that paid the costs of the Federal hydrosystem, not Federal taxpayers. As BPA's supply of power became unable to meet regional demand, BPA's preference customers bore more and more costs of the Federal hydrosystem.

The high cost of alternative sources of power caused BPA's non-preference customers to attempt to regain access to cheap Federal power. *Id*. at 30. Many areas served by IOUs moved to establish public entities designed to qualify as preference customers and be eligible for administrative allocations of power. Because the Project Act provided no clear way of allocating power among preference customers, and because the stakes involved in buying cheap Federal power had become very high, the competition for administrative allocations threatened to produce contentious litigation. *Id*. The uncertainty inherent in the situation greatly complicated the efforts by all BPA customers to plan for their future power needs. *Id*. at 31. In order to avoid the prospect of unproductive and endless litigation regarding access to the Federal power marketed by BPA, Congress enacted the Northwest Power Act in 1980. 16 U.S.C. §839 *et seq*.

The Northwest Power Act expressly reaffirmed the right of BPA's preference customers to first call on Federal power before such power could be offered to BPA's IOU or DSI customers. 16 U.S.C. §839g(c). The Northwest Power Act also established the REP. 16 U.S.C. §839c(c). As noted above, when BPA had insufficient Federal power to meet the needs of IOUs in the 1970s, such utilities developed their own resources, which generally were more costly than Federal hydropower. The REP provides PNW utilities a monetary form of access to low-cost Federal power. Under the program, PNW utilities may sell power to BPA at a rate based on the utility's ASC of its resources. BPA is required to purchase that power and sell, in exchange, an equivalent amount of power to the utility at BPA's PF rate. This is the same rate that applies to BPA's sales of power to its preference customers, although the Northwest Power Act expressly provides that the PF rate for the REP may be higher than the PF rate for preference customers due to the 7(b)(2) rate test described below. 16 U.S.C. §839e(b)(3). Where a utility's ASC is higher than BPA's PF rate, the difference between the rates is multiplied by the utility's jurisdictional residential load to determine an amount of money that is paid to the utility as Residential Exchange benefits. These benefits are passed through directly to the utility's residential consumers through lower retail rates. The cost of providing these benefits to exchanging utilities is borne primarily by BPA's publicly owned utility and DSI customers, subject to the rate ceiling established in section 7(b)(2) of the Northwest Power Act, which, as discussed below, protects preference customers from excessive costs of the REP.

Numerous, complex tradeoffs were necessary in order to resolve the competing claims for BPA's low-cost hydropower in the late 1970s, and in order to solve the electric power planning uncertainties facing the PNW at that time. The provisions of the Northwest Power Act reflect the give and take of those tradeoffs. While the Northwest Power Act established the REP to provide utilities a monetary form of access to low-cost Federal power, this access, or "share in the economic benefits" of Federal power, was expressly limited by a "rate ceiling" for preference customers to ensure that "[c]ustomers of preference utilities will not suffer any adverse economic consequences as a result of this exchange . . ." H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 35 (1980); *see also* H.R. Rep. No. 976, Part I, 96th Cong., 2d Sess. 34 (1980); S. Rep. No. 272, 96th Cong., 1st Sess. 15 (1979).

The preference customer "rate ceiling" was established in section 7(b)(2) of the Northwest Power Act. Section 7(b)(2) provides that after July 1, 1985, the rates charged for firm power sold to public body, cooperative, and Federal agency customers (exclusive of amounts charged those customers for costs specified in section 7(g) of the Northwest Power Act) may not exceed in total, as determined by the Administrator, such customers' power costs for general requirements if specified assumptions are made. In determining public body and cooperative customers' power costs for any rate period after July 1, 1985, and the ensuing four years, the following assumptions are made:

- the public body and cooperative customers' general requirements had included during such five-year period the DSI loads which are: (1) served by the Administrator; and (2) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives;

- public body, cooperative, and Federal agency customers were served, during such five-year period, with FBS resources not obligated to other entities under contracts existing as of the effective date of this Northwest Power Act (during the remaining term of such contracts) excluding obligations to DSI loads included in this paragraph;

- no purchases or sales by the Administrator as provided in section 5(c) were made during such five-year period;

- all resources that would have been required, during such five-year period, to meet remaining general requirements of the public body, cooperative, and Federal agency customers (other than requirements met by the available FBS resources determined under this paragraph) were: (1) purchased from such customers by the Administrator pursuant to section 6; or (2) not committed to load pursuant to section 5(b), and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional resources were obtained at the average cost of all other new resources acquired by the Administrator; and

- the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from: (1) reduced public body and cooperative financing costs as applied to the total amount of resources, other than

> FBS resources, identified under this paragraph; and (2) reserve benefits as a result of the Administrator's actions under this Northwest Power Act were not achieved.

16 U.S.C. §839e(b)(2).

The legislative history of section 7(b)(2) of the Northwest Power Act repeatedly and consistently recognizes that Residential Exchange benefits are subject to elimination or reduction due to the section 7(b)(2) rate ceiling. The report of the House Committee on Interior and Insular Affairs states:

> Section 5(c) of S. 885 contains provisions for a residential power "exchange." Under these provisions, any utility in the region would be entitled to sell to BPA an amount of power equal to the utility's residential and small farm load at the "average system cost" of such power and BPA would be required to sell back to each such utility an equivalent amount of power at a rate identical to what preference customers pay BPA for power to meet their "general requirements" (*subject to a "rate ceiling*").
>
> . . . This exchange will allow the residential and small farm consumers of the region's IOUs to share in the economic benefits of the lower-cost Federal resources marketed by BPA and will provide these consumers wholesale rate parity with residential consumers [of] preference utilities in the region. *Consumers of preference utilities will not suffer any adverse economic consequences as a result of this exchange since, as discussed below, the DSIs of BPA are required to pay the costs of the exchange during its initial years while a "rate ceiling" protects the customers of preference utilities during later years*.

H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 35 (1980) (emphasis added). The report reiterates this point:

> As an added protection against preference utilities and their customers suffering adverse economic consequences as a result of this legislation, section 7(b)(2) establishes a "rate ceiling" which is hypothetically intended to insure that these customers' rates will be no higher than they would have been had the Administrator not been required to participate in power sales or purchase transactions with non-preference customers under this legislation.

Id. at 36. The report emphasizes this point yet again:

> Subsection 7(b)(2) establishes a "rate ceiling" for BPA's preference customers, and specifies the method of calculating this ceiling, in order to insure such customers the cost benefits of their preference rights for sales under this subsection. Amounts not recoverable from preference customers because of this ceiling are to be recovered through supplemental rate charges for all other power sold by BPA under other provisions of section 7, as subsection 7(b)(3) specifies.

Id. at 52.

This intent that the section 7(b)(2) rate ceiling would protect preference customers from certain costs of the Northwest Power Act, including the costs of the REP, is also contained in the report of the House Committee on Interstate and Foreign Commerce. The report states:

> In addition, section 7(b) reserves for preference customers the price benefits for Federal power that they would have enjoyed in the absence of this legislation. This is accomplished by a "rate ceiling" which governs preference customer general requirements rates. Under this provision, the Northwest preference customers could pay less--but not more--for power under the legislation than they would have in any five-year period.

H.R. Rep. No. 976, Part I, 96th Cong., 2d Sess. 34 (1980). The report also notes:

> Section 7(b)(2) establishes a "rate ceiling" for preference customers that seeks to assure these customers that their rates will be no higher than they would have been had the Administrator not been required to participate in power sales or purchase transactions with non-preference customers under this Northwest Power Act. The assumption[s] to be made by the Administrator in establishing this ceiling are specifically set forth. It is through rate ceilings that this Northwest Power Act provides additional protection to public bodies and cooperatives' preference customers as to the price of the sale of power by the Administrator. In the event that this rate ceiling is triggered, then the additional needed revenues must be recovered from BPA's other rate schedules.

Id. at 68-69.

The establishment of a rate ceiling for preference customers is also noted in the report of the Senate Committee on Energy and Natural Resources:

> A rate test is provided in section 7 to insure that the Administrator's power rates for public bodies and cooperatives entitled to preference and priority under the Bonneville Project Act [are] no greater than would occur in the absence of the regional program established in S. 885.

S. Rep. No. 272, 96th Cong., 1st Sess. 20 (1979). The report also states:

> Section 7(b)--This section establishes a rate or rates for electric power sold to meet the general requirements (defined in this section) of public body cooperative and Federal agency customers and utilities under section 5(b)(2); a rate test to limit the charges that may be recovered by such rates applicable to public body, cooperative, and Federal agency customers after July 1, 1985; and a supplemental rate charge to recover any costs not recovered as a result of the rate test, to be applied through rates to all other power sales of the Administrator which are not limited by the rate test . . .

Id. at 32. This is reiterated in the Senate report. *Id*. at 56-59, 61-62. The report expressly recognizes that one item that may cause the rate test to trigger is an increase in the cost of the REP. The report states:

> The rate limit would reinstate the yardstick principle which has traditionally been used to support the multiple kind of utility ownership which exists in the PNW today. Other areas which appear to cause the rate limit to apply are slower preference customer load growth than IOU load growth, lower DSI loads, and *increased IOU exchange power costs.*

Id. at 62 (emphasis added).

In addition to section 7(b)(2) and its legislative history, section 5(c)(4) of the Northwest Power Act establishes that Congress was well aware that section 7(b)(2) could result in reduction or complete elimination of Residential Exchange benefits for utilities participating in the REP. Section 5(c)(4) provides:

> An electric utility may terminate, upon reasonable terms and conditions agreed to by the Administrator and such utility prior to such termination, its purchase and sale under this subsection if the supplemental rate charge provided for in section 7(b)(3) is applied and the cost of electric power sold to such utility under this subsection exceeds, after application of the rate charge, the ASC of power sold by such utility to the Administrator under this subsection.

16 U.S.C. §839c(c)(4). *See* S. Rep. 272, 96th Cong., 1st Sess. 15 (1979). In other words, the Northwest Power Act expressly contemplates that section 7(b)(2) could completely eliminate exchange benefits for utilities whose ASC rate was less than BPA's PF Exchange rate.

Pursuant to section 7(b)(2), BPA was required to implement the rate test for the first time in BPA's 1985 rate case. Prior to the 1985 rate case, on January 23, 1984, BPA published in the Federal Register a notice of a proposed "Legal Interpretation of Section 7(b)(2) of the PNW Electric Power Planning and Conservation Act." 49 Fed. Reg. 2911 (1984). This Legal Interpretation was intended to resolve the basic legal questions involved in the implementation of section 7(b)(2). BPA received comments and reply comments from all customers and interested parties and published a final Legal Interpretation on May 31, 1984. The Legal Interpretation has been used by BPA in every rate case since 1985 and was used in BPA's 2002 rate case.

Because of the importance and complexity of the 7(b)(2) rate test, and in order to provide customers certainty as to how section 7(b)(2) would be applied, BPA conducted a special evidentiary hearing that lasted from February 29, 1984, to August 17, 1984, to establish a Section 7(b)(2) Implementation Methodology. On March 26, 1984, BPA published in the Federal Register a notice of the *Proposed Section 7(b)(2) Implementation Methodology, Public Hearings, and Opportunities for Public Review and Comment*. 49 Fed. Reg. 11,235 (1984). BPA then conducted a formal evidentiary hearing on the methodology pursuant to section 7(i) of the Northwest Power Act. All of BPA's customers (public utilities, IOUs, and DSIs) intervened in the proceeding, in addition to state and Federal agencies and other interested parties. Both written and oral discovery was conducted. Direct and rebuttal testimony were filed by BPA and all parties. The Hearing Officer presided over two days of cross-examination. Parties filed briefs with BPA, and BPA reviewed and responded to the briefs in a draft 7(b)(2) Methodology. Parties then filed reply briefs. BPA issued a ROD including a final 7(b)(2) Methodology on August 17, 1984. *See* Section 7(b)(2) Implementation Methodology, b-2-84-F-02. The 7(b)(2) Methodology prescribes in detail how the 7(b)(2) test is to be conducted. The ROD and the 7(b)(2) Methodology address the major issues involving the implementation of section 7(b)(2), including reserve benefits, financing benefits, natural consequences, and the rate test trigger. The 7(b)(2) Methodology has been used by BPA in every rate case since 1985, when the 7(b)(2) rate test was first run, and was used in the development of BPA's 2002 rate case.

Section 7(b)(3) of the Northwest Power Act governs the allocation of costs in the event the 7(b)(2) rate test triggers. Section 7(b)(3) provides that "[a]ny amounts not charged to public body, cooperative, and Federal agency customers by reason of paragraph (2) of this subsection shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers." 16 U.S.C. §839e(b)(3). In other words, if the rate test triggers (*i.e.*, the rate ceiling for preference customers is exceeded), the costs in excess of the ceiling must be allocated to other power sales, including sales to utilities participating in the REP. These costs increase the PF Exchange rate, which is the rate at which BPA sells power to utilities participating in the Residential Exchange. When the PF Exchange rate increases, the difference between that rate and the utility's ASC rate decreases, resulting in a reduction of Residential Exchange benefits paid to the utility. Because each exchanging utility's ASC rate and residential load are different from those of other utilities, exchange benefits differ by utility. A utility receives no benefits when its ASC rate goes below BPA's PF Exchange rate.

As noted previously, section 7(b)(2) of the Northwest Power Act requires that BPA perform a "rate test" in each rate proceeding or "when setting rates" after July 1, 1985. 16 U.S.C. 839e(b)(2). The rate test ensures that BPA's preference customers' firm power rates applied to their general requirements are no higher than rates calculated using five specific assumptions that remove certain effects of the Northwest Power Act. Kaptur *et al*., WP-02-E-BPA-34, at 2. *See* Implementation ROD. The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements loads of BPA's public body, cooperative, and Federal agency customers (7(b)(2) or preference customers). Kaptur *et al*., WP-02-E-BPA-34, at 2. The two sets of rates are: (1) a set for the rate filing test period (FY 2002-FY 2006) and the ensuing 4 years (FY 2007-FY 2010) assuming that section 7(b)(2) is not in effect (Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (7(b)(2) Case rates). *Id*. The 7(b)(2) Case rates are modeled exactly the same as the Program Case rates except for the five assumptions listed in section 7(b)(2). *Id*. The five assumptions used to model the 7(b)(2) Case are:

1. Within or adjacent DSI loads are transferred to public utilities at the start of the 7(b)(2) rate test period; the remaining DSI loads are transferred to investor-owned utilities (IOUs) as BPA/DSI pre-Northwest Power Act contracts expire.

2. No section 5(c) Residential Exchange Program takes place.

3. Additional resources of three specified types serve the loads of 7(b)(2) customers when Federal Base System (FBS) resources are exhausted.

4. The DSI reserve benefits under provisions of the Northwest Power Act are not available in the 7(b)(2) Case. The 7(b)(2) Case rates will reflect this increased cost to the 7(b)(2) customers.

5. Financing benefits under provisions of the Northwest Power Act are not available in the 7(b)(2) Case. The 7(b)(2) Case rates will reflect this increased resource cost due to the absence of BPA financial backing if additional resources are required to serve 7(b)(2) customers.

Id. at 2-3. There may, however, be additional adjustments to reflect the natural consequences of the five assumptions. *See, e.g.*, Implementation ROD at 19-23. For a discussion of the development of the Program and 7(b)(2) Case rates, *see* Section 7(b)(2) Rate Test Study, WP-02-E-BPA-06, and Documentation, WP-02-E-BPA-06A. After the two sets of rates were developed, certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act were subtracted from the Program Case rates. *Id.* at 3. Next, the nominal rate for each year was discounted to the test year of the relevant rate case, in this case FY 2002. *Id*. The discounted Program Case rates were averaged, as were the 7(b)(2) Case rates. *Id*. Both averages were rounded to the nearest tenth of a mill for comparison. *Id*. Because the average Program Case rate was higher than the average 7(b)(2) Case rate, the rate test triggered, and an adjustment to the preference customers' Priority Firm Power (PF-02) rate was required. *Id*.

In summary, BPA has implemented the 7(b)(2) rate test in the 2002 rate case in the same manner as BPA always has conducted the test. BPA followed the provisions of section 7(b)(2) of the Northwest Power Act and BPA's Legal Interpretation of Section 7(b)(2), which has been in effect since 1984. BPA also has followed the 7(b)(2) Methodology, which provides detailed directions for conducting the rate test and which also has been implemented in the same manner since it was established in 1984. The significant trigger resulting from the rate test in BPA's 2002 rate proposal is the result of running the test with the data used in developing those rates. Clearly, as evidenced by section 5(c)(4) of the Northwest Power Act, the Northwest Power Act made no guarantee of Residential Exchange benefits. By the end of FY 2001, exchange benefits have totaled approximately $3.2 billion, and $240 million more benefits are forecasted to be provided over the next five years under BPA's 2002 proposal. While the 7(b)(2) rate test may result in an increase in the PF Exchange rate and thus, a decrease in the amount of benefits BPA provides utilities participating in the REP, failure to implement the test properly would be contrary to law and would defeat Congress's intent to establish a rate ceiling for BPA's preference customers. Issues regarding the implementation of the 7(b)(2) rate test are addressed below.

13.2 Conservation

Issue 1

Whether, in the calculation of the 7(b)(2) rate test, BPA should define conservation resources as replacements for FBS resources, and whether conservation resources in the section 7(b)(2) resource stack should be selected first to serve 7(b)(2) customer loads.

Parties' Positions

The IOUs argue that the Administrator must treat conservation as an FBS replacement, which would substantially increase Residential Exchange benefits and encourage conservation. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 16–17; IOU Ex. Brief, WP-02-B-AC/GE/IP/MP/PL/PS/EN-01, at 17-21. The IOUs argue that the Administrator should give policy direction to BPA staff responsible for performing the 7(b)(2) rate test to the effect that conservation should be included in the FBS. *Id.* The IOUs also argue that if BPA fails as a policy matter to treat conservation as an FBS replacement, the Residential Exchange benefits would be reduced by millions of dollars per year and future conservation would be discouraged. *Id.* at 19. PGE also argues that conservation should be included in the FBS. PGE Brief, WP-02-B-GE-01, at 7-8.

The PPC supports the BPA staff position that conservation resources in the 7(b)(2) rate test are not FBS resources. PPC Brief, WP-02-B-PP-01, at 72. Additionally, the PPC argues that the IOUs incorrectly argue that conservation resources must be selected from the 7(b)(2) Case resource stack first, and that BPA staff has correctly followed the prescribed treatment of conservation found in the Section 7(b)(2) Implementation Methodology ROD. *Id.*

BPA's Position

Conservation does not constitute an FBS resource. Kaptur *et al.*, WP-02-E-BPA-56, at 13-15. The Implementation ROD directs that conservation is not an FBS resource. *Id.* The Northwest Power Act does not require conservation to be treated as an FBS resource.

Evaluation of Positions

The IOUs argue that the Administrator should direct that conservation be included in the FBS because conservation is defined as a "resource" in the Northwest Power Act, and the term "resource" means "controlled or planned load reduction resulting . . . from a conservation measure." 16 U.S.C. §839a(19). IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 16-17; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 17. First, it is important to note that BPA has reviewed all of BPA's previous rate case RODs regarding the 7(b)(2) rate test since 1985, when the rate test was first performed. *See* 16 U.S.C. §839e(b)(2). In all of those RODs where BPA conducted the 7(b)(2) rate test, not a single party ever argued that conservation should be treated as an FBS resource. As discussed in greater detail below, there are good reasons why such an argument was never proffered.

While BPA agrees that conservation is a resource, during cross-examination BPA's witnesses noted that while conservation is a resource, it is a different kind of resource than actual sources of power. Tr. 1171. BPA's witnesses also affirmed that "conservation is separate and apart from the FBS." Tr. 2223. BPA's witnesses noted that in the 7(b)(2) Case "conservation resources are added to the inventory if the FBS is insufficient." Tr. 2224. Furthermore, conservation and FBS resources are defined separately in the Northwest Power Act. Section 3(3) of the Northwest Power Act defines conservation as "any reduction in electric power consumption as a result of increases in the efficiency of energy use, production, or distribution." 16 U.S.C. §839a(3). Section 3(10) of the Northwest Power Act defines FBS resources as noted in greater detail below. 16 U.S.C. §839a(10).

The Northwest Power Act also directs that the costs of conservation and the costs of the FBS must be allocated to loads differently. Section 7(b)(1) of the Northwest Power Act specifies how the costs of FBS resources are allocated to customer loads. Section 7(b)(1) provides:

> The Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the PNW, and loads of electric utilities under section 5(c). Such rate or rates shall recover the costs of that portion of the *FBS resources* needed to supply such loads until such sales exceed *FBS resources*. Thereafter, such rate or rates shall recover the cost of additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under section 5(c) and then from other resources.

16 U.S.C. §839e(b)(1) (emphasis added). Section 7(g) of the Northwest Power Act specifies how the costs of conservation resources are allocated differently than the costs of FBS resources. Section 7(g) provides:

> Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on the effective date of this Northwest Power Act, or by other provisions of this section, the Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this Northwest Power Act, all costs and benefits not otherwise allocated under this section, including, but not limited to, *conservation*, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under section 6, the cost of credits granted pursuant to section 6, operating services, and the sale or inability to sell excess electric power.

16 U.S.C. §839e(f) (emphasis added).

In addition to the fact that the costs of the FBS and conservation are treated differently under the Northwest Power Act for purposes of cost allocation, conservation and FBS resources are also expressly distinguished from each other in BPA's Section 7(b)(2) Implementation ROD, b-2-84-F-02. In 1984, BPA held a formal evidentiary hearing under section 7(i) of the Northwest Power Act to develop a methodology that would be used in all subsequent BPA rate cases to conduct the 7(b)(2) rate test. At the conclusion of the hearing, BPA issued a formal Section 7(b)(2) Implementation Methodology and an accompanying ROD. In the ROD and the 7(b)(2) Implementation Methodology, conservation resources are included as part of the three types of resources that are to be added if FBS resources are insufficient to meet 7(b)(2) customer loads:

> If FBS resources, after meeting contractual obligations, are insufficient to meet the general requirements of the 7(b)(2) customers, then three types of additional resources can be added to serve those loads. These additional resources are defined in section 7(b)(2) and are: (1) actual and planned resource acquisitions by BPA from 7(b)(2) customers consistent with the program case; (2) existing 7(b)(2) customer resources not currently dedicated to their regional load; and (3) generic resources at the average cost of actual and planned resource acquisitions from non7(b)(2) customers consistent with the program case. *These resources will include <u>any</u> conservation programs undertaken or acquired by BPA.* They will be assumed to come online to meet the remaining general requirements of 7(b)(2) customers *<u>after</u> FBS service* in order of least-cost first. The first two types of resources will come online in discrete increments, reflecting the actual size of the resource or the increment actually acquired by BPA. The third type will be brought online in the exact amount required to meet the 7(b)(2) customers' general requirements, reflecting their generic nature.

Implementation ROD, b-2-84-F-02, at 42 (emphasis added). Because the three types of resources include *any* conservation resources and are to come online *after* the FBS resources are exhausted, conservation resources cannot be FBS resources in the 7(b)(2) rate test.

This distinction between conservation and FBS resources can also be seen in the treatment of their respective costs in the COSA that BPA uses to determine the costs of resource pools and the allocation of those costs to rate pools. Kaptur *et al.*, WP-02-E-BPA-56, at 14. In the COSA06 tables, FBS resource costs are shown on lines 2-11, NR costs are shown on lines 12-17, Residential Exchange resource costs are shown on line 18, and Conservation and Energy Services Business costs are shown on lines 19 and 20. *Id.; see* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 49-53. The costs of conservation and the costs of FBS resources are listed separately in the COSA because the Northwest Power Act prescribes different cost allocation methodologies for each of them. As noted above, section 7(b)(1) of the Northwest Power Act outlines how the costs of FBS resources, Residential Exchange resources, and new resources are allocated to rate pools. 16 U.S.C. §839e(b)(1). Section 7(g) of the Northwest Power Act outlines how other costs, including the costs of conservation, are allocated. 16 U.S.C. §839e(g). Also, as an applicable section 7(g) cost, the cost of conservation is removed from the Program Case PF rates before the calculation of the 7(b)(2) rate test trigger. 16 U.S.C. §839e(b)(2).

The IOUs and PGE argue that the Administrator should direct that conservation be included in the FBS, because the Northwest Power Act, 16 U.S.C. §839d(b) and §839b(e)(1), requires that BPA give conservation first priority when acquiring resources. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01 at 16-17; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 17; PGE Brief, WP-02-B-GE-01, at 7. First, it must be noted that the Northwest Power Act does not simply provide that conservation is automatically a first priority in acquiring resources. BPA's conservation acquisitions are complete if BPA's Administrator determines that such acquisitions are consistent with the Regional Council's Plan. 16 U.S.C. 839d(a)(1). The Northwest Power Act also imposes cost-effectiveness and other standards for conservation acquisitions. 16 U.S.C. 839a(4)(A). If conservation fails these requirements, BPA need not acquire it. The IOUs' argument also does not establish a legal requirement that compels the Administrator to take such action. The Northwest Power Act and legislative history regarding BPA's resource acquisitions make clear that BPA is not required to treat conservation as an FBS replacement. In passing the Northwest Power Act, Congress granted the Administrator the authority to acquire resources. Section 6(a)(2) of the Northwest Power Act provides that:

> In addition to acquiring electric power pursuant to section 5(c), or on a short-term basis pursuant to section 11(b)(6)(i) of the Federal Columbia River Transmission Act (Transmission System Act), the Administrator shall acquire, in accordance with this section, sufficient resources to meet [her] contractual obligations that remain after taking into account planned savings from measures provided in paragraph 1 of this subsection, and to assist in meeting the requirements of section 4(h) of this Northwest Power Act.

16 U.S.C. §839d(a)(2). The definition of FBS resources in the Northwest Power Act recognizes that BPA may acquire resources to replace reductions in capability of the FBS resources. Section 3(10) of the Northwest Power Act defines FBS resources as:

> [T]he FCRPS hydroelectric projects; resources acquired by the Administrator under long-term contracts in force on the effective date of this Northwest Power Act; and resources acquired by the Administrator *in an amount necessary to replace reductions in the capability of the resources referred to in subparagraphs (A) and (B) of this paragraph*.

16 U.S.C. §839a(10) (emphasis added).

The Administrator's acquisition authority is set forth in section 6 of the Northwest Power Act. 16 U.S.C. §839d. Section 6 does not compel the Administrator to use conservation as an FBS replacement. Since implementation of the section 7(b)(2) test began, BPA has never determined that conservation is an appropriate resource for purposes of replacing reductions in the capability of the FBS, and therefore it has not been included for purposes of section 7(b)(2).

Subsection 6(a)(1) of the Northwest Power Act establishes a conditional priority for conservation and renewables to reduce the demand for electric power and thus to lessen the need to acquire power from physical generation resources. 16 U.S.C. §839d(a)(1). Subsection 6(a)(2) expands the Administrator's existing authority to acquire resources after taking into account planned savings from conservation. Subsection 6(b) defines the manner in which the Administrator is to acquire resources, including non-Federal resources to replace FBS resources. Subsection 6(b)(4) provides:

> The Administrator shall acquire any non-Federal resources to replace FBS resources only in accordance with the provisions of this section. The Administrator shall include in the contracts for the acquisition of any such non-Federal replacement resources provisions which enable [her] to ensure that such non-Federal replacement resources are developed and operated in a manner consistent with the considerations specified in section 4(e)(2) of this Northwest Power Act.

16 U.S.C. §839d(b)(4). Resources that replace the FBS are to be acquired consistent with BPA's obligation to take into account the savings or planned savings from conservation.

> For the long-term, section 6 authorizes the BPA to acquire 'resources' to meet these contractual obligations. However, in providing this authority, the Committee was mindful of the concerns by some this authority not provide a 'blank check' to BPA to acquire whatever resources it deems appropriate. The Committee limited that authority and set priorities . . . Further, the Committee amendment provides that BPA must first 'take into account planned savings from conservation and conservation measures.'

Senate Rep. No. 96-976, Part I, 96th Cong., 2d Sess. at 37 (1979).

The definitions of the FBS and other related terms support BPA's determination that resources acquired to replace lost capability of the FBS refers to power generation resources which have output and capability that are "compatible" with the existing regional power system. *See* 16 U.S.C. §839b(e)(2). The statutory predicate for replacing the FBS results from reductions in the capability of the FBS. The term "resource" is defined in section 3(19) of the Northwest Power Act and means: "(A) electric power, including the actual or planned electric power capability of generating facilities, or (B) actual or planned load reduction resulting from direct application of a renewable energy resource by a consumer, or from a conservation measure." 16 U.S.C. §839a(19)(A), (B). Finally, the term "electric power" is defined in section 3(9) to mean "electric peaking capacity, or electric energy, or both." 16 U.S.C. §839a(9). Taken together, these terms demonstrate the linkage between the FBS's capability to produce electric power, and replacement resources that produce electric energy and can replace reductions in the capability of the FBS. On the one hand, BPA is directed to seek reduction in demand for electric power consumption through conservation programs and renewable resources. On the other hand, notwithstanding the efforts to reduce demand through conservation, Congress understood that the FBS is in reality a set of physical generating resources whose reduced capability must be replaced by resources that add to the capability of the FBS.

Senate Report 96-976, Part II, 96th Cong., 2d Sess. (1980), provides further intent on FBS replacement resources. "Paragraph (3), dealing with resources acquired to replace FBS resources, clarifies that BPA will be able to require that such resources be developed and operated consistent with section 4(e)(2) of this legislation. Paragraph (4) requires BPA to continue to acquire and implement conservation measures and conservation resources and certain renewable resources pursuant to section 6(a) regardless of other resource acquisition." *Id.* at 49. Congress did not intend to bar the Administrator from acquiring "conventional" resources.

Rather, Congress struck a balance between reducing demand for electric power consumption, on the one hand, and the need to acquire power from generating resources, on the other. Because Congress specified criteria, the Administrator is compelled to "take a hard look" at non-conventional resources before determining the need to acquire conventional resources. Both the Committee statements and the language of section 6 of the Northwest Power Act acknowledge that when BPA has acquired conservation consistent with the NWPPC's Plan, the Administrator must acquire electric power from other resources. "Section 6(b) requires BPA to acquire sufficient resources to meet its contractual obligations, after taking into account planned savings from measures provided in section 6(a)…." *Id.* at 35. At the same time, the Administrator must not reduce efforts to acquire and implement conservation measures and resources. "Thus, sections 6(a) and 6(b) together require the Administrator to achieve all available conservation and prevent [her] from acquiring non-conservation resources without first taking into account planned savings from conservation." *Id.* at 37. In the context of replacements in the reduction of FBS resources, BPA takes into account BPA's planned savings from conservation and then replaces reductions in the capability of the FBS resources with power producing resources.

The PPC supports BPA's position on conservation. The PPC points out that the IOUs' argument that conservation resources be selected first from the 7(b)(2) resource stack is based upon the Northwest Power Act requirement that conservation be given first priority, found at 16 U.S.C. §839(e)(1). The PPC argues that this citation is misleading, as it addresses BPA's responsibilities with respect to conservation in general, and not the specific treatment of conservation resources in the 7(b)(2) rate test. PPC Brief, WP-02-E-PP-09, at 47, 72. The PPC argues that a more precise authority on treatment of conservation resources in the 7(b)(2) Case of the 7(b)(2) rate test is the Implementation ROD, which addresses this issue directly. *Id.* That document directs BPA to place all resources in the 7(b)(2) resource stack (including conservation programs undertaken or acquired by BPA) in least-cost order. *See* Implementation ROD, b-2-84-F-02, at 42. BPA has treated conservation resources in the 7(b)(2) stack consistent with the directives laid out in the Implementation ROD. *Id.*

The IOUs argue that BPA notes that the Northwest Power Act requires BPA to give conservation first priority when acquiring resources, but the IOUs do not cite any such BPA statement. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 18. As noted previously, BPA established that conservation has a conditional priority in acquiring resources and is not automatically the first resource that must be acquired. The IOUs then argue that BPA argues that there is no legal requirement that "*compels* the Administrator to take such action," citing Draft ROD, WP-02-A-01, at 13-10 to 13-11, and that "BPA is not *required* to treat conservation as an FBS replacement, citing Draft ROD, WP-02-A-01, at 13-11. *Id*. (emphasis added by IOUs). BPA's statements are correct. As explained in greater detail above, the Northwest Power Act and its legislative history viewed as a whole do not require that conservation be used as an FBS replacement. The conditional priority given to conservation acquisitions does not dictate that conservation must be used as an FBS replacement. Just the opposite: BPA acquires sufficient power resources to meet its contractual obligations after taking into account planned savings from measures provided in section 6(a) of the Northwest Power Act.

The IOUs argue that BPA notes that it "may acquire resources to replace reductions in the capability of the FBS resources," citing Draft ROD, WP-02-A-01, at 13-11, and that this authority "is set forth in section 6 of the Northwest Power Act," citing Draft ROD, WP-02-A-01, at 13-11. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 19. The IOUs then argue that BPA states that "section 6 does not compel the Administrator to use conservation as an FBS replacement," even though BPA admits that "Subsection 6(a)(1) of the Northwest Power Act establishes a priority for conservation and renewables," citing Draft ROD, WP-02-A-01, at 13-11. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 19. As noted above, the IOUs confuse the conditional priority of conservation with the issue of whether conservation is properly an FBS replacement resource.

The IOUs argue that BPA argues that the FBS can never include conservation as a replacement resource even though BPA acknowledges that resources include conservation under the Northwest Power Act, and that BPA concludes that "BPA has not disputed that conservation is a resource. Congress did not say, however, that conservation is an FBS resource. This is the pending issue," citing Draft ROD, WP-02-A-01, at 13-21. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 19. Once again, the IOUs make the simplistic argument that if conservation is a resource and has a conditional priority, it must be used as an FBS replacement. As demonstrated by BPA's lengthy legal analysis set forth above, this argument is not persuasive in light of a complete review of the Northwest Power Act and its legislative history, which distinguish conservation from generating resources in the determination of FBS replacement resources.

The IOUs argue that BPA has the issue backward: that unless there is a clear unequivocal Congressional expression of intent to exclude conservation from the FBS in order to protect preference customers and penalize residential consumers of IOUs, conservation should be included as an FBS replacement resource. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 20. BPA disagrees with the IOUs' new and unsupported standard. The true standard is that BPA must review the statute as a whole and its legislative history and determine whether conservation was intended to be an FBS replacement resource. BPA's thorough legal analysis determined that conservation is not an FBS replacement resource. BPA must make its determination based on the law and not based on whether its decision would protect or penalize particular customer groups.

The IOUs and PGE argue that BPA's 7(b)(2) rate test panel believed it did not have discretion to treat conservation as an FBS resource. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 17, and PGE Brief, WP-02-B-GE-01, at 7, both citing Kaptur *et al.*, WP-02-E-BPA-56, at 14-15, and Tr. 2216-19. The IOUs argue that BPA's witnesses viewed this as a policy issue. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 17. The IOUs argue that as a policy issue, the Administrator can direct that conservation be treated as an FBS replacement resource. *Id.* The IOUs have misrepresented BPA's rebuttal testimony. Nowhere in the rebuttal testimony cited by the IOUs does the 7(b)(2) rate test panel state that they viewed the question of including conservation resources in the FBS as a policy issue. *Id.; see* Kaptur *et al.*, WP-02-E-BPA-56, at 14-15. Rather, the rebuttal testimony outlines the BPA panel's understanding of the Northwest Power Act and the Implementation ROD with respect to the treatment of conservation costs in the 7(b)(2) rate test. The Northwest Power Act explicitly distinguishes between how

FBS costs are to be allocated to customer loads and how conservation costs are to be allocated to customer loads. Section 7(b)(1) of the Northwest Power Act outlines how the costs of FBS resources, Residential Exchange resources, and new resources are allocated to rate pools. 16 U.S.C. §839e(b)(1). Section 7(g) outlines how other costs, including the costs of conservation, are to be allocated. 16 U.S.C. §839e(g). In addition, the Implementation ROD expressly distinguishes between how FBS resources are to be used to serve 7(b)(2) customer loads and how conservation resources can be added to the 7(b)(2) Case resource inventory used to serve 7(b)(2) customer loads. The Implementation ROD describes the three types of resources, including any conservation resources, that are available to come online to serve 7(b)(2) customer loads after the FBS resources are exhausted. BPA's rebuttal testimony makes clear that BPA did not have discretion to treat conservation as an FBS resource, because to do so would violate BPA's understanding of the Northwest Power Act and the Implementation ROD. The issue of the treatment of conservation costs in the 7(b)(2) rate test is not a policy issue that is amenable to administrative fiat.

The IOUs have also misrepresented the cross-examination testimony of BPA's 7(b)(2) rate test panel. Nowhere in the cross-examination testimony cited by the IOUs, Tr. 2216-19, does the 7(b)(2) rate test panel state that they viewed the question of including conservation resources in the FBS as a policy issue. The panel repeatedly stated that they did not consider conservation to be an FBS resource. Tr. 2217-18. The panel stated that historical conservation could not be part of the FBS in the 7(b)(2) Case, because the 7(b)(2) Case stack of resources to be used in the event that the FBS is insufficient to serve 7(b)(2) customer loads included programmatic conservation for each year starting in 1981. Tr. 2218-19. Particularly telling is that during cross-examination, counsel for the IOUs described the issue of conservation in the FBS as a legal issue, not a policy issue:

> "Q. Assume we have a debate, just for the purposes of this question, and that conservation is in the FBS already, if you make that assumption, *which is a legal conclusion,* then your sentence in the ROD could be interpreted to mean …"

Tr. 2219 (emphasis added). The IOUs' own statements admit that the issue of whether conservation should be part of the FBS is a legal issue, not a policy issue. BPA's rebuttal testimony and cross-examination testimony, as well as the IOUs' own admissions, all support BPA's position that the question of including conservation resources in the FBS is a legal issue, not a policy issue as the IOUs now contend.

The IOUs argue that nothing in the Northwest Power Act precludes the BPA Administrator from treating conservation as an FBS resource. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 17, citing Tr. 2219. First, BPA's panel was not comprised of lawyers. BPA's witnesses are therefore not able to make legal conclusions. Nevertheless, the 7(b)(2) panel's understanding of the Northwest Power Act is that there is no explicit language prohibiting conservation resources from being treated as FBS resources, nor is there explicit language requiring that conservation resources be treated as FBS resources. Tr. at 2216. Obviously, this does not mean that conservation resources are FBS resources. Upon further legal analysis, as noted above and as discussed in further detail below, there is explicit language in the Northwest Power Act that distinguishes between conservation resources and FBS resources in terms of how they are used to serve loads and how their costs are allocated to customer loads. These explicit distinctions, and more detailed arguments discussed below, establish that conservation resources and FBS resources are not one and the same. Also as stated above, the Implementation ROD and BPA's interpretation of the Northwest Power Act make an explicit distinction between conservation resources and FBS resources used to serve 7(b)(2) customer loads in the 7(b)(2) Case of the 7(b)(2) rate test.

In addition, on pages 4 and 5 of the Implementation ROD, there is a discussion about the concern that three parties had about the possible double-counting of conservation costs in the 7(b)(2) rate test. It was determined in this discussion that, while it may be theoretically possible for some or all conservation costs to be double-counted, it did not occur in all instances:

> This is because billing credits and programmatic conservation are added to the resources used to serve the 7(b)(2) customers only to the extent that they are needed after the FBS is exhausted and only in the event that they are the least-cost resources to be added. If the FBS is sufficient to serve the 7(b)(2) load, or other available additional resources have lower costs, then billing credits and programmatic conservation will not be added to the 7(b)(2) case.

Implementation ROD, b-2-84-F-02, at 5. The clear language in both the Northwest Power Act and the Implementation ROD preclude the Administrator from treating conservation as an FBS resource in the 7(b)(2) rate test.

The IOUs argue that if BPA includes conservation in the FBS, BPA will increase residential benefits and will encourage cost-effective conservation. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 17. The IOUs state that BPA's 7(b)(2) rate test panel agrees that including conservation in the FBS encourages cost-effective conservation. *Id.*, citing Kaptur *et al*.,WP-02-E-BPA-56, at 15. Once again the IOUs have misrepresented BPA's rebuttal testimony. The actual text of the relevant answer is:

> A. BPA agrees with the general theoretical argument that if electric power costs were made to be artificially high in the PNW, conservation would be a comparatively more cost-effective alternative. However, BPA does not believe that higher energy costs are a net benefit to the region.

Kaptur *et al*., WP-02-E-BPA-56, at 15, lines 18-21. This subject was also brought up by the IOUs' attorney during the cross-examination of the BPA's 7(b)(2) rate test panel:

> Q. (Mr. Marshall) You agreed that if other rates went up, electric power costs rates went up, that conservation would become comparatively more cost-effective as an alternative. Right?
>
> A. (Mr. Doubleday) We were answering an IOU argument that seems to have said that since conservation is a good thing, that higher rates in the region would foster more of this good thing so, therefore, higher rates would be a good thing. And I think we said that, however, BPA does not believe that higher energy costs are a net benefit to the region.

Tr. 2220. Whether conservation is a more or a less cost-effective alternative to BPA power sales is not a consideration when performing the 7(b)(2) rate test. BPA staff responsible for conducting the test are directed by their understanding of the Northwest Power Act and the Implementation ROD. The PPC noted that the IOUs suggest that one benefit of treating conservation as they suggest in the 7(b)(2) Case would be to artificially increase rates to BPA's preference customers so as to make conservation relatively more cost-effective. PPC Brief, WP-02-B-PP-01, at 72-73, citing Hoff *et al*., WP-02-E-AC/GE/IP/MP/PL/PS-03, at 28. BPA's witnesses have said that raising cost-based rates while lowering rates to BPA's other customers for the purpose of promoting conservation is not consistent with the purpose of section 7(b)(2) of the Northwest Power Act. PPC Brief, WP-02-B-PP-01, at 73; Tr. 2247-48.

The IOUs argue that Congress did not intend to insulate preference customers from the costs of conservation and that Congress wanted to encourage conservation, but BPA would protect preference customers from conservation costs and discourage conservation by establishing artificially low rates for preference power instead of treating conservation as an FBS replacement and increasing Residential Exchange benefits and encouraging conservation. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 17. BPA disagrees with this argument. First, the preference customers' PF Preference rate is not insulated from the costs of conservation. The PF Preference rate contains such costs. While Congress wanted to encourage conservation, it is still doing so through BPA's many conservation programs and expenditures. Further, BPA is not establishing artificially low rates for preference customers or high rates for exchange customers; instead, BPA is properly not including conservation as an FBS replacement resource. This is a correct decision and its effect on the PF rate or the PF Exchange rate is not the basis for BPA's decision.

The IOUs cite a number of statements made by BPA's general policy witnesses during cross-examination. These witnesses did not do any work regarding BPA's determination that conservation resources are not FBS resources, and are not lawyers and are not qualified to perform legal analyses regarding whether conservation is an FBS resource under the Northwest Power Act. Indeed, counsel for the IOUs expressly admitted that the issue of whether conservation is an FBS resource is a legal issue. Tr. 2219. Throughout their cross-examination regarding the treatment of conservation in the 7(b)(2) rate test, BPA's policy witnesses were asked legal questions and technical questions by the IOUs' attorney that they were not qualified to answer. BPA's policy witnesses testified that while they were not technical experts on the 7(b)(2) rate test, they did know that the test followed a prescribed methodology, including about how conservation was treated. Tr. 133. BPA's policy witnesses testified that their understanding is that the 7(b)(2) panel performing the 7(b)(2) rate test were ". . . not being driven by the dollar amount and/or other factors, but trying to stay true to what the test requires. That's the fundamental thing driving them there." Tr. 137. BPA's policy witnesses testified repeatedly that they were not qualified to determine if conservation had been used or should be used to replace some of the capability of the FBS. One of BPA's policy witnesses testified that "[t]he term 'replacements' I think might carry with it, dare I say, a technical term in that I believe there is some statutory limits to the way and amount of Federal Base System that Bonneville replaces. And I'm not qualified to get into an expansive or probably even a narrow discussion of FBS replacement as it pertains to statute." Tr. 140. BPA's other policy witness testified that "…but once again you're stretching beyond at least my ability to probably give you concise, clear answers about all requirements when it comes to what does or doesn't qualify for ratemaking purposes replacement to the Federal Base System. I think there are some other panels coming up who could get at that." Tr. 139. BPA's policy witnesses recognized that the legal/technical issue of the treatment of conservation in the 7(b)(2) rate test is not a policy issue, and repeatedly stated that as policy witnesses they did not feel qualified to address that issue.

The IOUs argue that BPA's general policy witness said that 724 aMW of conservation have replaced FBS resources in the ordinary sense of the word. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 18-19, citing Tr. 141. As noted previously, BPA's policy witnesses' conceptions of whether conservation has replaced FBS resources, which are made in the absence of knowledge about section 7(b)(2) of the Northwest Power Act, the Section 7(b)(2) Legal Interpretation, or the Section 7(b)(2) Implementation Methodology, do not state and are not used in BPA's determination of that issue, which is guided by legal and technical analyses. The logical meaning of the witness's statement is that if BPA loses power from resources, conservation programs that reduce demand can be generally viewed, even if not technically or legally correct with regard to FBS replacements, as making up for such losses. When viewed by BPA's legal and technical experts who did the actual work on this issue, this simplistic understanding is clearly wrong. The Northwest Power Act plainly establishes that resources do not automatically replace reductions in the capability of the FBS as suggested by the IOUs. BPA must take particular actions in determining whether resources replace such reductions. 16 U.S.C. §839d. The record does not establish that BPA ever took such actions regarding conservation, and therefore conservation has never been an FBS resource. In addition, directly contrary to the IOUs' arguments, BPA's witnesses testified that "BPA has *never* proposed that conservation be used as an FBS replacement." Kaptur *et al*., WP-02-E-BPA-56, at 15 (emphasis added).

The IOUs argue that BPA's witness could offer no policy reason why BPA would not want to define and treat conservation as an FBS replacement. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 19. This issue, however, is not a policy issue. This is a legal and technical issue. BPA's legal and technical reasons for not treating conservation as an FBS replacement are stated at great length in this ROD. These reasons establish that, regardless of whether there is or is not a policy reason to treat conservation as an FBS replacement, legally and technically it is inappropriate to do so.

The IOUs argue that BPA does not address the adverse consequences of not including conservation in the FBS from the perspective of Congressional intent. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 20. The IOUs argue that the adverse effects are reductions in Residential Exchange benefits by tens of millions of dollars per year. *Id*. The IOUs argue that BPA does not argue that Congress intended to penalize residential consumers of IOUs by excluding conservation from the FBS. *Id*. The IOUs argue that the legislative history of the Northwest Power Act shows that conservation was a Congressional priority, and it was to be paid for by all customers. *Id*. The IOUs argue that the effect of not treating conservation as an FBS resource is to protect preference customers from the cost of conservation and create a rate disparity Congress never intended. *Id*. The IOUs argue that BPA provides no compelling reason why it would choose to protect one set of customers from conservation costs that Congress intended all regional customers to share. *Id*. First, BPA has addressed the issue of the consequences of making determinations on section 7(b)(2) issues from the perspective of Congressional intent. As discussed at great length in the introduction to this chapter, the Northwest Power Act expressly contemplates that section 7(b)(2) could completely eliminate exchange benefits for utilities whose ASC was less than BPA's PF Exchange rate. There is no statutory guarantee to any particular level of benefits for exchanging utilities. In addition, BPA previously presented a thorough legal analysis regarding why Congressional intent, as reflected in the Northwest Power Act and its legislative history, support the proposition that conservation was not intended to be an FBS replacement resource. The legislative history of the Northwest Power Act does not provide that conservation was to be an FBS replacement resource. The costs of conservation are paid for by all customers though an allocation under section 7(g) of the Northwest Power Act, not through the treatment of conservation as an FBS resource in the section 7(b)(2) rate test. With regard to the argument that the preference customers' PF Preference rate is insulated from the costs of conservation, to the contrary, the PF Preference rate contains such costs. While Congress wanted to encourage conservation, it is still doing so through BPA's many conservation programs and expenditures. Further, BPA is not establishing artificially low rates for preference customers or high rates for exchange customers; instead, BPA is properly not including conservation as an FBS replacement resource. This is a correct decision, and its effect on the PF rate or the PF Exchange rate is not the basis for BPA's decision. While the IOUs argue that the effects of this decision reduce Residential Exchange benefits by tens of millions of dollars per year, if BPA adopted the erroneous position of the IOUs, this would similarly create adverse effects of tens of millions of dollars per year for BPA's preference customers and deny such customers their statutory rate protection under section 7(b)(2). BPA's decision is made on its merits, not to penalize or reward any particular customer or customer class.

The IOUs argue that BPA's general policy witness acknowledged that conservation was a main goal of BPA and the Northwest Power Act. *Id.*, citing Tr. 134. BPA has never disputed that conservation is a main goal of the Northwest Power Act. This does not mean, however, that BPA should ignore the legal and technical reasons why it is inappropriate to include conservation as an FBS resource. The IOUs also argue that BPA's witness agreed that conservation is defined as a "resource under the 1980 Northwest Power Act." *Id.*, citing Tr. 135-136. While, technically, the definition of conservation in the Northwest Power Act does not define conservation as a resource, 16 U.S.C. §839a(3), the definition of resource in the Northwest Power Act includes conservation, 16 U.S.C. §839a(19). Again, BPA has never disputed this, but this does not mean that BPA should ignore the legal and technical reasons why it is inappropriate to include conservation as an FBS resource.

The IOUs argue that BPA's general policy witness stated that there is "nothing wrong with conservation as a replacement," if BPA loses other FBS resources, *Id.*, citing Tr. 136-137; and that "there are certain priorities given to conservation when it comes to replacement of the FBS." *Id.*, citing Tr. 136-137. Again, as noted above, BPA's policy witnesses did not do any work regarding BPA's determination that conservation resources are not FBS resources, and are not lawyers and are not qualified to perform legal analyses regarding whether conservation is an FBS resource under the Northwest Power Act. Indeed, counsel for the IOUs expressly admitted that the issue of whether conservation is an FBS resource is a legal issue. Tr. 2219. BPA's policy witnesses testified repeatedly that they were not qualified to determine if conservation had been used or should be used to replace some of the capability of the FBS. Tr. 139, 140. BPA's policy witnesses recognized that the legal and technical issue of the treatment of conservation is not a policy issue, and repeatedly stated that as policy witnesses they did not feel qualified to address that issue. When viewed by BPA's legal and technical experts who did the actual work on this issue, however, this simplistic understanding is clearly wrong. As previously noted in great detail, it is inappropriate to treat conservation as an FBS replacement. The IOUs also argue that BPA's policy witness stated that "there are certain priorities given to conservation when it comes to replacement of the FBS." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 18. The immediately foregoing responses apply equally to this argument. BPA's policy witnesses have no knowledge of whether conservation legally can be an FBS replacement. Therefore, they have no knowledge of whether there are priorities regarding conservation in that circumstance. Notably, the BPA witnesses that are experts on the 7(b)(2) rate test and were responsible for the determination of whether conservation should be viewed as an FBS resource filed detailed testimony that disagreed with the admittedly uninformed answers given by BPA's policy witnesses. BPA's policy witnesses admitted extremely limited knowledge about the 7(b)(2) rate test and FBS replacements and deferred to BPA's expert panels that actually conducted the analysis on these issues.

The IOUs argue that BPA's general policy witness testified that from 1980 to now, BPA has acquired 724 aMW of conservation and that if BPA had not acquired that conservation "you would have had to build other resources or find other replacements for that power." *Id.*, citing Tr. 140. The IOUs argue that BPA also testified that since December 5, 1980, the capability of the FBS has decreased by more than 2,600 aMW, and in that period of time BPA added 724 aMW of conservation. *Id.*, citing Tr. 2221; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 17. These arguments mean little. With regard to the argument that absent BPA's conservation efforts, BPA would have had to find power, this does not mean that the power acquisitions would be FBS replacements. In section 7(b)(1), the Northwest Power Act recognizes that BPA can acquire "other" power. In BPA ratemaking, such power constitutes new resources, not FBS resources. Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 38. FBS resources, exchange resources, and new resources are all separately established in the Northwest Power Act. 16 U.S.C. §839e. New resources are allocated differently than FBS resources. *Id.* As noted previously, replacements of reductions in the FBS are not automatic. As BPA noted, BPA previously proposed to replace reductions in the FBS only one time, in 1996, and issued letters as part of a public process to make a determination regarding FBS replacements. Tr. 1163-64. BPA also established that "BPA has never proposed that conservation be used as FBS replacements." Kaptur *et al*., WP-02-E-BPA-56, at 15. This means that the 724 aMW of conservation never became FBS resources. Thus, that reductions in the capability of the FBS comprise over 2,600 aMW and that BPA's conservation efforts have produced 724 aMW of savings does not establish that the latter replaced reductions in the capability of the FBS.

The IOUs argue that BPA's technical panel has taken a tortured and narrow interpretation of an internal implementation decision, to conclude that conservation was not technically a replacement, despite the plain words of the statute and the plain fact that conservation has been acquired and has replaced lost FBS resources. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 19-20, citing Implementation ROD, b-2-84-F-02; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 18, 20-21. The IOUs go on to argue that the BPA panel points to the Implementation ROD, at 42, which, *the IOUs claim*, states that "If FBS resources . . . are insufficient to meet the general requirements of 7(b)(2) customers, then three types of additional *conservation* resources can be added to meet these loads." *Id.*, citing Kaptur *et al*., WP-02-E-BPA-56, at 13. The IOUs argue that but for conservation that is in the FBS, that sentence is simply not applicable, because that sentence addresses only treatment of conservation after the FBS is determined to be insufficient. *Id.* The IOUs argue that the Implementation ROD can be read to assume that the FBS is full and therefore, did not address the addition of conservation to the FBS. *Id.*

Contrary to the IOUs' arguments, BPA has previously established that the plain words of the statute do not show that conservation is an FBS replacement. Quite the opposite, the plain words of the statute and its legislative history establish that conservation was not intended to be an FBS replacement. In addition, contrary to the IOUs' arguments, BPA has established the plain fact that conservation has never been acquired to replace reductions in the capability of FBS resources.

With regard to the IOUs' remaining arguments, the IOUs have once again misrepresented BPA's rebuttal testimony. In this case, the IOUs have gone beyond mere misrepresentation of the BPA panel's rebuttal testimony and have actually fabricated new language for the Implementation ROD. The IOUs then use their fabricated language to support their arguments. BPA's Implementation ROD states:

> If FBS resources, after meeting contractual obligations, are insufficient to meet the general requirements of the 7(b)(2) customers, *then three types of additional resources can be added to serve those loads*. These additional resources are defined in section 7(b)(2) and are: (1) actual and planned resource acquisitions by BPA from 7(b)(2) customers consistent with the program case; (2) existing 7(b)(2) customer resources not currently dedicated to their regional load; and (3) generic resources at the average cost of actual and planned resource acquisitions from non-7(b)(2) customers consistent with the program case. *These resources will include any conservation programs undertaken or acquired by BPA.*

Kaptur *et al*., WP-02-E-BPA-56, at 13, lines 17-22 (emphasis added). As noted above, the actual language of the Implementation ROD, at 42 states: "three types of additional resources can be added to serve those loads." The IOUs, however, do not quote the actual language of the Implementation ROD, but present a quotation of the language amended in a manner that attempts to favor their case. The IOUs' fabricated quotation states: "three types of additional *conservation* resources can be added to meet loads." (Emphasis added.) The IOUs' fabrication attempts to imply that conservation was already a part of the FBS, and that the Implementation ROD was referring to the additional conservation that could be added over and above that which was already in the FBS. The actual language of the Implementation ROD is clear and is contrary to the IOUs' fabrication. The resources available for serving 7(b)(2) customer load after the FBS resources are exhausted include any conservation programs undertaken or acquired by BPA. The resources available for serving 7(b)(2) customer load after the FBS resources are exhausted are shown in the 7(b)(2) Case resource stack. *See* 7(b)(2) Rate Test Study Documentation, WP-02-E-BPA-06A, at 49. The 7(b)(2) Case resource stack shows conservation resources for each year starting in 1982. *Id.* Logically, if all BPA programmatic conservation is included in the resources to be used after FBS resources are exhausted, then the FBS resources cannot contain any of these same BPA programmatic conservation resources.

Incredibly, the IOUs go on to argue that their fabricated Implementation ROD language ("[i]f FBS resources … are insufficient to meet the general requirements of 7(b)(2) customers, then three types of additional conservation resources can be added to meet these loads") can be rephrased with no change in meaning to reflect the inclusion of conservation as an FBS resource:

> If existing FBS *conservation and other* resources … are insufficient to meet the general requirements of the 7(b)(2) customers, then three types of *additional* conservation and other resources can be added to serve those [7(b)(2)] loads …

IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 20. The IOUs' attempt to fabricate language and then to use a paraphrase of that fabrication to support the manner in which they would like to see an issue resolved is extremely disturbing. BPA staff, however, must be directed by the actual language in the Northwest Power Act and the Implementation ROD when conducting the 7(b)(2) rate test. The actual language of the ROD clearly establishes that conservation resources are *not* to be considered to be part of the FBS resources, either in the Program Case or in the 7(b)(2) Case of the 7(b)(2) rate test. The IOUs' argument that their fabricated language can be read in yet a different way to support their position on the treatment of conservation resources in the 7(b)(2) Case is obviously not persuasive.

In their brief on exceptions, the IOUs argue that BPA committed an uncalled-for and specious attack on the IOUs' argument that the term "resources" could be read to mean conservation and other resources. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 18. The IOUs have mischaracterized BPA's criticism. BPA did not criticize the IOUs for making their argument, BPA criticized the IOUs' fabrication of language in BPA's Implementation ROD in an attempt to bolster their argument. BPA's criticism is therefore neither uncalled-for nor specious. Such improper conduct cannot be ignored.

The IOUs argue that BPA's 7(b)(2) rate test panel said the IOUs' foregoing interpretation is one of a "family of interpretations" that could be used. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 20, citing Tr. 2219. Again, the IOUs have misrepresented BPA's cross-examination testimony. A true statement of the question and answer follows:

> Q. (Mr. Marshall) Assume we have a debate, just for the purposes of this question, *and that conservation is in the FBS already, if you make that assumption, which is a legal conclusion,* then your sentence in the ROD could be interpreted to mean that if existing FBS resources are insufficient to meet 7(b)(2) customer loads, additional resources, including three types that you quote on lines 19 through 21 of your testimony, are to be added.

A. (Mr. Keep) Right. As you so amended it, given your caveats, of the family of interpretations that you could then put on it, that may be one of them.

Tr. 2219 (emphasis added). First, as is evident throughout this section of BPA's ROD, conservation resources cannot be used as FBS replacements. BPA's COSA and 7(b)(2) witnesses did not say otherwise. With regard to the IOUs' foregoing argument, BPA's witness was clearly answering a hypothetical question posed by the IOU attorney that specified that conservation was assumed to be in the FBS already, and was not agreeing with the IOUs' fabricated Implementation ROD language cited above.

The IOUs argue that BPA cannot hide behind one of its own ambiguous and vague implementation decisions to deny what Congress intended. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 21. The IOUs argue that Congress expressly defined conservation as a "resource," 16 U.S.C. §839(a)(B). *Id.* The IOUs argue that Congress intended to provide Residential Exchange benefits that are not diminished by the failure to subtract conservation costs in the 7(b)(2) test. *Id.* The IOUs argue that BPA, in an argument so convoluted as to defy understanding, has denied the plain meaning of these Congressional mandates. *Id.* The IOUs argue that the end result is to deny millions of dollars a year of benefits to residential and rural customers of the region and to discourage conservation. *Id.* at 20-21.

The IOUs' argument that BPA cannot hide behind one of its own "ambiguous and vague" implementation decisions to deny what Congress intended is clearly unfounded. First, BPA's Section 7(b)(2) Implementation Methodology is hardly a generic implementation decision. As noted previously, in 1984, BPA held a formal evidentiary hearing under section 7(i) of the Northwest Power Act to develop a methodology that would be used in all subsequent BPA rate cases to conduct the 7(b)(2) rate test. At the conclusion of this extensive and contested hearing, BPA issued a formal Section 7(b)(2) Implementation Methodology and an accompanying ROD. This was no mere implementation decision, this was the establishment of an important methodology that would guide BPA ratemaking for years to come. Furthermore, the IOUs' argument that the Implementation Methodology is "ambiguous and vague" is utterly unsupported. As noted above, the Implementation ROD clearly states that "[i]f FBS resources, after meeting contractual obligations, are insufficient to meet the general requirements of the 7(b)(2) customers, *then three types of additional resources can be added to serve those loads. . . These resources will include any conservation programs undertaken or acquired by BPA.*" Kaptur *et al*., WP-02-E-BPA-56, at 13.

The IOUs argue that Congress expressly defined conservation as a resource. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 21. As noted above, BPA has not disputed that conservation is a resource. Congress did not say, however, that conservation is an FBS resource. This is the pending issue. As for the IOUs' argument that Congress intended to provide Residential Exchange benefits that are not diminished by the failure to subtract conservation costs in the 7(b)(2) rate test, BPA has explained previously that this was not Congress's intent with regard to FBS replacements, as evidenced by the Northwest Power Act and its legislative history. While the IOUs claim that their benefits have been reduced due to BPA's failure to subtract conservation costs, conservation costs are and always have been subtracted from the Program Case rates in the 7(b)(2) rate test, including in the current case.

While the IOUs argue that BPA's argument is "so convoluted as to defy understanding," this *ad hominem* attack is unfounded. As seen from the extensive preceding discussion, BPA's analysis is straightforward and logical. While the IOUs profess not to understand BPA's argument regarding the treatment of conservation in the 7(b)(2) rate test, BPA has followed the very same treatment of conservation costs in all previous rate cases where the test was conducted, going back to 1985. The IOUs have apparently not understood BPA's position despite having the last 15 years to do so. In this rate case, BPA has used the language of the Northwest Power Act, its legislative history, the 7(b)(2) Implementation Methodology ROD, BPA's direct and rebuttal testimony, and BPA's cross-examination testimony to support its longstanding position. The IOUs, on the other hand, have repeatedly misrepresented BPA's testimony and fabricated new language in the Implementation ROD in an attempt to support their position, a position they have never previously taken since the inception of the 7(b)(2) rate test in 1985. While the IOUs argue that the exclusion of conservation from the FBS is arbitrary and capricious and an abuse of discretion and violates Congressional intent, IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 21, BPA's foregoing review of this issue establishes that BPA's position is well-reasoned, consistent with Congressional intent, and supported by the administrative record and the law.

Decision

BPA continues to treat conservation costs in the 7(b)(2) rate test as conservation costs and not FBS costs. Conservation resources are not part of the FBS. As expressly prescribed by the 7(b)(2) Implementation Methodology, conservation resources are placed in the 7(b)(2) resource stack with other available resources in order of least-cost first.

13.3 Costs of Uncontrollable Events

13.3.1 Planned Net Revenues for Risk

Issue 1

Whether BPA's PNRR constitute the costs of uncontrollable events and thus should be excluded from the Program Case.

Parties' Positions

The IOUs argue that the costs of PNRR (over $127 million per year for five years) are costs of uncontrollable events that should be subtracted from the "program case" of the 7(b)(2) rate test. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 23. The IOUs argue that PNRR are by definition a cost for risks of events that cannot be controlled. *Id*. at 24.

PPC argues that PNRR do not constitute a cost of uncontrollable events. PPC notes that PNRR is an element of BPA's risk analysis, which mitigates for a wide yet identified range of uncertainties in factors such as hydro conditions and market prices. PPC Brief, WP-02-B-PP-01, at 70. In addition, PPC notes that "'[u]ncontrollable events' is a statutory term referring to discrete events which differ from the continuum of changing events that occur in nature, business and government." *Id.*, quoting Kaptur *et al.*, WP-02-E-BPA-56, at 11.

BPA's Position

PNRR do not constitute the costs of uncontrollable events. Kaptur *et al*., WP-02-E-BPA-56, at 11-13. PNRR should not be excluded from the Program Case, because BPA has not identified any costs as being costs of uncontrollable events in this rate case. *Id*. at 11. The cost of mitigating a wide range of uncertainties is not the same as the cost of uncontrollable events. *Id*. at 12. PNRR costs are not the costs of uncontrollable events and should not be included in the section 7(g) adjustment in the 7(b)(2) rate test. *Id*. at 13.

Evaluation of Positions

Section 7(b)(2) of the Northwest Power Act provides that:

> After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, *exclusive of amounts charged such customers under subsection (g) for the costs of* conservation, resource and conservation credits, experimental resources and *uncontrollable events*, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator assumes that . . .

16 U.S.C. §839e(b)(2) (emphasis added).

Section 7(g) of the Northwest Power Act provides that:

> Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on the effective date of this Northwest Power Act, or by other provisions of this section, the Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this Northwest Power Act, all costs and benefits not otherwise allocated under this section, including, but not limited to, conservation, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under section 6, the cost of credits granted pursuant to section 6, operating services, and the sale or inability to sell excess electric power.

16 U.S.C. §839e(g). The analysis of whether there are costs of "uncontrollable events" that should be excluded from the Program Case must begin with an interpretation of this statutory term. The IOUs argue that the plain meaning of the word "event" is defined as "something that happens," which is not limited in any manner whatsoever and applies to any occurrence that is beyond BPA's control. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 23, n. 62. The IOUs also argue that BPA is trying to quantify and limit a term in a way that the plain words Congress used does not limit. *Id*. at 23. The IOUs' proposed interpretation, however, makes little sense in the context of the 7(b)(2) rate test. There are millions of "events" that occur daily and which are beyond BPA's control. It is impossible to identify each event that has occurred and which might

have some impact on BPA's costs. Congress could not reasonably have intended to impose such an elusive and impractical standard upon BPA. This is confirmed by a review of the statutory context of this term. BPA must interpret the statute in a manner that is consistent with the context in which it is used, that is, the 7(b)(2) rate test. As noted previously, the 7(b)(2) rate test compares PF rates for preference customers under two scenarios: with and without the specific assumptions of section 7(b)(2). This fact suggests that Congress intended the comparison to be between rates that share the same basic costs but for the specific statutory exceptions. For this reason, uncontrollable events should be construed such that they do not exclude costs from the Program Case that are due to conditions that simply vary over time and which typically are reflected in rates. For this reason, uncontrollable events are not properly viewed as all conceivable events beyond BPA's control, but rather the discrete and significant events beyond BPA's control that differ from the continuum of changing conditions that occur in nature, business, and government and are routinely reflected in rate development.

Section 7(b)(2) of the Northwest Power Act excludes certain applicable section 7(g) costs, including the costs of uncontrollable events, from the Program Case. Section 7(b)(2) refers to "the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, *exclusive of amounts charged such customers under subsection (g) for the costs of . . . uncontrollable events . . .*" 16 U.S.C. §839e(b)(2) (emphasis added). The exclusion of the costs of uncontrollable events from the Program Case is tied expressly to the "amounts *charged* such [preference] customers under subsection (g) for the costs of . . . uncontrollable events." In other words, one must look to the costs of uncontrollable events that actually were "charged" to preference customers in the Program Case, which reflects BPA's rate proposal. This is confirmed by BPA's Legal Interpretation of Section 7(b)(2), which emphasizes that applicable 7(g) costs are only those "chargeable to 7(b)(2) customers." *See* Legal Interpretation of Section 7(b)(2), b2-84-FR-03, at 5. BPA, however, did not identify any particular events as uncontrollable events for which costs were allocated according to section 7(g). Kaptur *et al.*, WP-02-E-BPA-56, at 11-12. Because BPA has not identified any uncontrollable events subject to section 7(g) allocation, it would be inappropriate to select any particular costs to be viewed as uncontrollable events only for the 7(b)(2) rate test. *Id.* Therefore, no adjustment should be made to the Program Case. The IOUs argue that BPA determined that since no costs of uncontrollable events were identified as chargeable to preference customers, there are no uncontrollable events. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 24. The IOUs argue that the costs of PNRR are known and that BPA should acknowledge that the costs of PNRR are the costs of uncontrollable events. *Id*. Simply because the costs of PNRR are known does not mean that they should be treated as the costs of uncontrollable events. The determination of whether the costs of PNRR constitute the costs of uncontrollable events must be made on its merits, as discussed in greater detail in this section.

The IOUs argue that by not characterizing PNRR as the costs of uncontrollable events, "BPA slashed Residential Exchange benefits from $280 million to $37 million." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PL-01, at 22. Contrary to the IOUs' claim, BPA has not "slashed" Residential Exchange benefits by its treatment of this issue. Instead, as discussed in greater detail below, PNRR are clearly not the costs of uncontrollable events. This means that BPA has properly conducted the 7(b)(2) rate test, and the forecasted Residential Exchange benefits are properly determined. If BPA had not treated this issue properly, by excluding the costs of PNRR from section 7(g) costs in the Program Case, then the Residential Exchange benefits to exchanging utilities would have provided an improper windfall that they did not deserve under the implementation of the 7(b)(2) rate test.

The IOUs argue that BPA's section 7(b)(2) witnesses made no independent review of whether any costs of uncontrollable events existed. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PL-01, at 22. In addition, the IOUs assert that when BPA's section 7(b)(2) panel was asked if they made an independent determination of whether any uncontrollable events should be included in the 7(b)(2) test, they responded "[t]hat's not my job." *Id.*, quoting Tr. 2184. These facts, however, support the fact that BPA conducted the 7(b)(2) rate test in the proper manner. The IOUs' suggestion that the BPA panel's witnesses should have made an "independent review" is misplaced, because it is not the role of the 7(b)(2) staff to determine whether events are uncontrollable. The workgroups responsible for accounting decisions make the determination whether any costs within BPA's COSA are the costs of uncontrollable events. Because the revenue requirement workgroup included no costs of "uncontrollable events" in their cost figures, BPA's section 7(b)(2) panel properly included no such costs in the 7(b)(2) rate test. Tr. 2184. In developing rates and performing the 7(b)(2) rate test, the 7(b)(2) panel uses a series of models called the RAM. The RAM is designed to perform the 7(b)(2) rate test and develop the posted rates using the relevant data for the rate test period. Specialists throughout BPA develop the rate test period data inputs used in the calculation of the 7(b)(2) rate test trigger. Kaptur *et al*., WP-02-E-BPA-56, at 7. During the cross-examination of BPA's section 7(b)(2) panel, IOU counsel questioned BPA's witnesses as to who in BPA would make the determination of an uncontrollable event. Tr. 2184. The BPA witness replied that "[i]n particular he was on one of the panels, I believe it was DeWolf, *et al*., I believe that was the Panel." Tr. 2184. In addition, BPA's witness again identified that the revenue requirements experts were responsible for providing information, noting that "We are assuming when our revenue requirements--they'll indicate to us what--if there are any uncontrollable event costs." *Id.*

BPA conducts a regional process for determining the spending levels and program costs for the rate period. In this process there is a comprehensive review of all cost by the regional customers, including parties most affected by the designation of 7(g) costs. Tr. 563. During the cross-examination of BPA's revenue requirements panel, IOU counsel posed questions as to the process BPA uses to develop its revenue requirements.

> Q. (Mr. Marshall) Everything is open in a revenue requirement, all costs, whether it be costs of fiberoptics, costs of having too many employees, costs of going to Congress to talk about things, all those costs are open to debate before the rate is set and before the charges are made tariffs, correct?
>
> A. (Mr. DeWolf) Right.
>
> Q. (Mr. Marshall) But here some aren't and some are, right?
>
> A. (Mr. DeWolf) No, it isn't correct.

Q. (Mr. Marshall) Some are and some aren't, isn't that correct?

A. (Mr. DeWolf) All of the costs included in the revenue requirement have been subject to public review and discussion, and remain so, outside the 7(i) process. In a cost review process, an extensive regional review process and similarly with issues '98', and similarly with fish costs, developing the Fish and Wildlife Funding principles. So exclusion from the 7(i) process, I mean our basic logic is twofold here. That debate has been held, No. 1; and No. 2, the door remains open for continuing discussions outside the rate proceeding on the wisdom and merits of spending levels.

Tr. 563.

BPA's 7(b)(2) panel is responsible for relying on the data provided by the experts in the area of revenue requirements. In addition, these experts have testified that BPA goes through an extensive regional process to determine not only the level of costs but also the nature of those costs. The revenue requirements experts did not identify any costs of uncontrollable events. In addition, it is clear that BPA would include the cost of an "uncontrollable event" as a "line item in the revenue requirements" if such an event occurred. Tr. 2185.

The IOUs acknowledge that BPA argued that the costs of PNRR are not the costs of uncontrollable events because BPA has not identified any costs as being the costs of uncontrollable events in this rate case. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 23. The IOUs also acknowledged that the 7(b)(2) staff had not identified such costs because it was not their role, and that the 7(b)(2) staff said that it was the role of the revenue requirement panel, and such costs had been considered in a public review process. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 23. The IOUs argue that the implication of the Draft ROD was that the revenue requirements panel did not identify any costs of uncontrollable events because no one in the public review process made such an identification. *Id*. The IOUs argue that the Draft ROD does not explain how the public in that comment process would know that it was incumbent upon them to classify a cost as an uncontrollable event. *Id*. The IOUs argue that it appears that no one was responsible for determining whether or not each cost included in the revenue requirement was uncontrollable. *Id*. The IOUs argue that BPA uses a questionable negative inference to bootstrap a positive statement that PNRR is not an uncontrollable event. *Id*. The IOUs have misunderstood the process that was previously described by BPA. BPA did not say that the revenue requirements panel did not identify any costs of uncontrollable events because no one in the public review process made such an identification. BPA noted that BPA's 7(b)(2) panel is responsible for relying on the data provided by the experts in the area of revenue requirements. In addition to the revenue requirements staff's own expert analysis, BPA goes through an extensive regional process to determine not only the level of costs but also the nature of those costs. The revenue requirements experts, through their review, and through participation in the public review process, did not identify any costs of uncontrollable events. While there is no specific statement regarding how the public would be advised to comment on the uncontrollable nature of costs, any general discussion of a particular cost would necessarily describe the nature of the particular cost. This dialogue would inform BPA's revenue requirements experts, who would then determine whether an uncontrollable event occurred and, if so, incorporate the cost of an "uncontrollable event" as a "line item in the revenue requirements." Tr. 2185. While the IOUs argue that it appears that no one was responsible for determining whether or not each cost included in the revenue requirement was uncontrollable, the foregoing discussion has consistently noted that BPA's revenue requirements experts make such determinations. Contrary to the IOUs' allegations, BPA has not used a questionable negative inference to bootstrap a positive statement that PNRR is not an uncontrollable event, but rather has examined the issue carefully and concluded that, based on the record and the law, PNRR do not constitute costs of uncontrollable events.

The IOUs argue that the costs of PNRR (over $127 million a year for five years) are costs of uncontrollable events that should be subtracted from the "program case." IOU Brief, WP-02-B-AC/GE//IP/MP/PL/PS-01, at 23. The IOUs argue that if risks of future events were controllable there would be no need for a risk reserve. *Id*. First, this issue was addressed in part above where BPA explained why uncontrollable events are not properly viewed as all conceivable events beyond BPA's control, but rather the discrete and significant events beyond BPA's control that differ from the continuum of changing conditions that occur in nature, business, and government and are routinely reflected in rate development. In addition, however, BPA's direct testimony states that "the $127 million of PNRR is the amount necessary, together with CRAC and other measures, to *mitigate* the wide uncertainties we face to achieve the 88 percent Treasury Payment Probability standard. PNRR, however, is only one component of the total cash flow for risk." Kaptur *et al.*, WP-02-E-BPA-56, at 12, quoting Lovell *et al*., WP-02-E-BPA-14, at 13 (emphasis added). During cross-examination of the revenue requirements panel, Dr. Lovell added clarification of the nature of the costs included within PNRR:

> In the revenue requirement that we talked about before, for instance, we have some point estimates of various costs that are quite uncertain. The uncertainty around these costs is often brought into the picture in the risk analysis. The plan[ned] net revenue for risk number is calculated during the risk analysis process.
>
> Some of the money that's collected in the -- through the plan[ned] net revenue for risk entry in the revenue requirement is due to the nature or the risks, not to the sort of costs that one usually thinks of as a cost.

Tr. 568. Dr. Lovell also explained that PNRR is impacted by the fish and wildlife program:

> As you know, there is no single fish and wildlife plan at this time. We are faced with uncertainty. In the revenue requirement we have entered deterministic values for some of the financial impacts of the fish and wildlife program because the revenue requirement has to have single point estimate values. The uncertainty over that sort of cost is in the risk analysis, so we do not have a single cost of the fish and wildlife program. So to the extent that the cost can not be captured by a single number, some aspects of the cost are captured only in the risk analysis. In addition, one of the categories of financial impact of the fish and wildlife program is the operational impacts, which are captured in the risk analysis.

Tr. 646.

The point that BPA is making is that the revenue requirement estimates are point value estimates. There is inherent risk in making estimates, which requires a mechanism to buffer the risks so as to ensure an outcome that allows BPA to recover its costs over time. BPA has stated that "[t]he purpose of the plan[ned] net revenues for risk is to increase reserves, but not simply to pay costs, but also to act as a buffer against risks, many of which are uncertainties in costs." Tr. 569. In addition to the costs defined by Dr. Lovell above, BPA defined the range of uncertainties to include: "operating risk – Hydro and thermal generation performance, California market prices, Southwest gas prices, and generating and non-generating public utility load uncertainty." Kaptur *et al*., WP-02-E-BPA-56, at 12. BPA also noted that BPA incurred nonoperating risks, including "fish and wildlife operations and maintenance and capital recovery expenses and other expenses." *Id.*; Revenue Requirement Study, WP-02-E-BPA-02, at 22-23. PPC agrees with BPA that PNRR is an element of BPA's risk analysis, which mitigates for a wide yet identified range of uncertainties in factors such as hydro conditions and market prices. PPC Brief, WP-02-B-PP-01, at 70. PPC notes that "'[u]ncontrollable events' is a statutory term referring to discrete events which differ from the continuum of changing events that occur in nature, business and government." *Id*., quoting Kaptur *et al*., WP-02-E-BPA-56, at 9. PPC notes that there is not sufficient evidence for BPA to treat PNRR as an uncontrollable event in the 7(b)(2) rate test calculation. *Id*.

The IOUs argue that BPA's section 7(b)(2) panel refused to recognize BPA's costs of risk as costs of uncontrollable events, because they were told that in the 1996 rate case the costs of "uncontrollable events" were recognized only if they were "discrete events not routinely reflected in ratemaking." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 23, citing Kaptur *et al*., WP-02-E-BPA-56, at 11-12. The IOUs have once again mischaracterized BPA's testimony. BPA's testimony simply states that "[a]s BPA recognized in its 1996 rate case, 'uncontrollable events' is a statutory term that logically refers to discrete events, which differ from the continuum of changing events that occur in nature, business and government." Kaptur *et al*., WP-02-E-BPA-56, at 11. This testimony does not state that BPA's witnesses refused to identify costs of risks as uncontrollable events because they were told something in 1996. The interpretation of the statutory term "uncontrollable events" is a legal matter. While legal advice is generally consistent, and it would be no surprise if legal advice were consistent through any number of rate cases, BPA counsel continually reviews such advice in each rate case to determine if any events would suggest that original legal advice was in error. Part of this review occurs through the evaluation of the parties' briefs. Having reviewed such briefs, however, BPA believes that its legal interpretation of section 7(b)(2) is correct.

The IOUs argue that the BPA panel did not know whether the cost of an uncontrollable event was intended to indicate the cost of an insurance policy or an insurance reserve to cover the risks of future events--events that could not be controlled. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 23, citing Tr. 2196. BPA has not characterized PNRR as an insurance policy. As stated above, PNRR is a tool to mitigate the risk of a wide range of uncertainty around costs. PNRR is not a mechanism that insures BPA against the cost of potential discrete events that have significant impacts on BPA, such as Mt. Hood erupting and causing severe damage to Bonneville Dam or many other possible events. The development of BPA's risk models does not include the analysis of events that have little likelihood of occurring, such as the high impact, low probability event of a nuclear war. Though the event would be considered large and expensive, the assigned probability would be infinitesimal, leading to an expected cost of virtually zero. However, in the case of PNRR, there is the assumption of risk within the continuum of normal business costs, which are routinely included in ratemaking.

The IOUs note that BPA determined that the cost of mitigating a wide range of uncertainties is not the same as the cost of uncontrollable events. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 24. The IOUs argue that BPA confuses the process of dealing with events that are uncontrollable (mitigation) with the events themselves. *Id*. The IOUs argue that if the events were controllable, they would not need mitigation, they would need payment. *Id*. The IOUs argue that it is only because the event is uncontrollable that a mitigation scheme that deals with the (uncontrollable) uncertainties is needed. *Id*. The IOUs argue that risk mitigation is necessary only if events are beyond one's control. *Id*. Again, the IOUs are confusing the ability to perfectly control a cost item with the ability to perfectly forecast the future outcome of that cost item. Obviously, there are millions of cost-related items over which BPA has less than perfect knowledge or control. The amount of heavy load hour power consumed by a specific customer during a specific day in a specific month of a specific year is an example of something which BPA cannot precisely know or perfectly control. However, BPA can make a point forecast of that load and statistically calculate an amount of PNRR that will help mitigate the uncertainty surrounding that point forecast. To characterize the cost of serving that specific load as the cost of an uncontrollable event would be absurd. If the cost of an item is not perfectly known, that lack of perfect knowledge does not, in itself, mean the item is an uncontrollable event. If the event itself is not an uncontrollable event, mitigating the forecast uncertainty around the event's point estimate cannot be the cost of an uncontrollable event.

As noted previously, the IOUs' proposed interpretation makes little sense in the context of the 7(b)(2) rate test. There are millions of "events" that occur daily and which are beyond BPA's control. It is impossible to identify each event that has occurred and which might have some impact on BPA's costs. Congress could not reasonably have intended to impose such an elusive and impractical standard upon BPA. This is confirmed by a review of the statutory context of this term. BPA must interpret the statute in a manner that is consistent with the context in which it is used, that is, the 7(b)(2) rate test. As noted previously, the 7(b)(2) rate test compares PF rates for preference customers under two scenarios: with and without the specific assumptions of section 7(b)(2). This fact suggests that Congress intended the comparison to be between rates that share the same basic costs but for the specific statutory exceptions. For this reason, uncontrollable events should be construed such that they do not exclude costs from the Program Case that are due to conditions that simply vary over time and which typically are reflected in rates. For this reason, uncontrollable events are not properly viewed as all conceivable events beyond BPA's control or perfect knowledge, but rather the discrete and significant events beyond BPA's control that differ from the continuum of changing conditions that occur in nature, business, and government and are routinely reflected in rate development.

To support the argument that PNRR is not an insurance policy against the cost of an uncontrollable event, BPA's 7(b)(2) panel stated during cross-examination that the cost of an "uncontrollable event" such as Mt. Hood erupting would not be taken out of PNRR.

Q. (Mr. Marshall) Let us assume, going back to your hypothetical that Mt. St. Helens or Mt. Hood blows up tomorrow, and you now have 50 years of extra costs from that billion dollars of uncontrollable events. Would any of that come out of PNRR?

A. (Mr. Keep) My understanding of how we would do that is that once the uncontrollable event occurred, the mountain blows up, we decide how we are going to deal with those costs. Let us continue with the hypothetical that instead of continuing in this rate case, since it happened tomorrow, say, that we would do a supplemental. And if we figured out how we were going to deal with those costs, those costs would actually be projections of costs and be known costs and there would not be any risk around them. And my understanding of the risk analysis is that once you have a known event, it ceases to be something that's taken into account by the risk analysis.

Tr. 2191. As illustrated in this testimony, the cost of an "uncontrollable event" would be considered an event that has been recognized and determined to be an event that necessitates a separate line item within the revenue requirement. In addition, given that the cost is known and measurable, it would have very little risk associated with it. The cost of PNRR would therefore not be affected by this event. PPC notes, in addition, that when asked during cross-examination whether money collected through PNRR would cover the cost of an uncontrollable event, BPA's witnesses were clear that: (1) an uncontrollable event identified before or during a rate proceeding would be separately identified as such in the revenue requirement, Tr. 2182-85; and (2) BPA would not necessarily utilize money collected through PNRR to cover the cost of an uncontrollable event, Tr. 2192-93. PPC Brief, WP-02-B-PP-01, at 70.

The IOUs note that BPA stated that "BPA would not necessarily utilize money collected through PNRR to cover the cost of an uncontrollable event," citing Draft ROD, WP-02-A-01, at 13-28. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 25. The IOUs argue that the only basis for this statement appears to be testimony that the huge costs of a hypothetical event such as Mt. Hood erupting would not be taken out of PNRR, but rather BPA would instead probably file a supplemental rate case to deal with those costs, citing Draft ROD, WP-02-A-01, at 13-27. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 25. The IOUs argue that the necessary implication is that the PNRR would be used to pay for all costs of uncontrollable events except for the most enormously expensive of such costs. *Id*. BPA disagrees. The "necessary implication" inferred by the IOUs, that PNRR would be used to pay for all costs of uncontrollable events except for the most enormously expensive of such costs, indicates a lack of understanding about BPA's ratemaking process. As stated above, PNRR does not represent or pay for the costs of uncontrollable events. PNRR is a mechanism for mitigating a wide range of uncertainty around the normal continuum of business costs. Also as discussed above and in other chapters of this ROD, PNRR has the effect of increasing BPA's cash reserves. These increased cash reserves help to mitigate the uncertainties around many of BPA's forecasted ratemaking point estimates, and help to ensure that BPA can achieve the anticipated TPP. PNRR is not a separate fund used to pay for specific types of costs. PNRR is not an insurance policy that will pay off if certain events occur.

The IOUs argue that the intent of Congress was not to protect preference utilities from the costs of events that would have occurred whether the Northwest Power Act was enacted or not; in other words, Congress did not want the costs of uncontrollable events to cut benefits to Residential Exchange customers. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 24; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 22. The IOUs argue that BPA's witnesses agreed that "an uncontrollable event is by definition something that would have occurred whether the Regional Power Act was enacted or not enacted." *Id*., quoting Tr. 2210. The IOUs argue that BPA's PNRR are by definition a cost for risks of events that cannot be controlled, and these risks would have occurred whether the Northwest Power Act was enacted or not. *Id*. These IOU arguments are unclear. First, the IOUs state that the intent of Congress was not to protect preference customers from the costs of events that would have occurred whether the Northwest Power Act was enacted or not, arguing that BPA's witnesses agreed that an uncontrollable event would occur whether or not the Northwest Power Act was enacted. *Id*. The IOUs, however, provide no citation to authority in support of this argument. The intent of Congress was to protect preference customers' rates from certain costs as described in section 7(b)(2) of the Northwest Power Act. 16 U.S.C. §839e(b)(2). For these costs, the statute prescribes their treatment, and it does not matter if these costs would have occurred whether or not the Northwest Power Act was enacted. What matters is whether, in a particular rate case, BPA has incurred costs from an uncontrollable event and, if so, whether such costs are treated as section 7(g) costs and are deducted from the Program Case. As BPA has established in previous discussion, the costs of PNRR are not the costs of uncontrollable events. In addition, the IOUs' argument is not persuasive because, in the event that BPA incurred costs for uncontrollable events, public agencies would pay rates that included the allocation of those costs under section 7(g), and exchanging utilities would not pay more than public agencies if these costs were also reflected in the PF Exchange rate.

The IOUs argue that BPA criticized the IOUs' failure to cite authority for the proposition that the intent of Congress was not to protect preference customers' rates from the costs of events that would have occurred whether or not the Northwest Power Act was enacted. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 25. The IOUs argue that the intent is clear from the language and structure of the statute. *Id*. The IOUs, however, continue to cite no authority for this proposition except for the allegation that BPA pointed out that preference customers' rates would be no higher than they would have been had the Northwest Power Act not been enacted. *Id*. The IOUs, however, do not cite an actual statement of BPA on this proposition, but rather cite a Senate report related to the Northwest Power Act. *Id*. The Senate report provides, in part, that "[a] rate test is provided in section 7 to insure that the Administrator's power rate for public bodies and cooperatives entitled to preference and priority under the Bonneville Project Act [are] no greater than would occur in the absence of the regional program established in S. 885." *Id*. The IOUs' argument reflects a common error. While some people refer to the Program Case and the 7(b)(2) Case as the "with Act" and "without Act" cases, this generalization is not accurate. If this were the case there are dozens if not hundreds of provisions of the Northwest Power Act that would have to be deleted from the 7(b)(2) Case. Congress did not do so. Instead, there are five assumptions in section 7(b)(2) that must be used in conducting the rate test. It is not whether the costs of the events would have occurred whether or not the Northwest Power Act was enacted, but rather, as in this case, whether a cost is a cost of an uncontrollable event. The IOUs argue that done correctly, the application of 7(g) lowers the Program Case costs, thereby ensuring that the rate test does not trigger when the costs of serving preference customers (exclusive of costs of uncontrollable events) in the Program Case are compared with all costs (including uncontrollable events) in the 7(b)(2) Case. *Id*. The IOUs argue that as a result, uncontrollable events that would have occurred regardless of whether the Northwest Power Act was enacted show up as identical costs in both cases, and therefore the difference between the two is zero. *Id*. The IOUs argue that BPA has effectively negated the impact of the exclusion of the costs of uncontrollable events. *Id*. This argument is not persuasive. BPA has conducted the section 7(b)(2) rate test correctly, and BPA has determined that there are no costs that can be defined as the costs of uncontrollable events in this rate proceeding. The IOUs' overly broad and incorrect definition of uncontrollable events as anything that BPA cannot control or have perfect future knowledge about would result in a section 7(b)(2) rate test that could never trigger. Congress would not have provided the PF Preference ratepayers with a rate protection mechanism that would never provide any rate protection.

The IOUs argue that BPA's statement that it does not matter if these costs would have occurred whether or not the Act was passed suggests a fundamental misunderstanding of the rate test because it is those costs and only those costs that are of importance in the test. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 26. BPA disagrees with the IOU argument that costs that would have occurred whether or not the Act was passed are the only costs that are of importance in the test. Fundamentally, the cost of operating and maintaining the Federal hydropower system does not depend on passage of the Northwest Power Act. However, the Northwest Power Act directs how BPA is to define the costs of the system and how rates are to be set to recover those costs. For these costs, the statute prescribes their treatment, and it does not matter if these costs would have occurred whether or not the Northwest Power Act was enacted. What matters is whether, in a particular rate case, BPA has incurred costs from an uncontrollable event and, if so, whether such costs are treated as section 7(g) costs and are deducted from the Program Case. As BPA has established in previous discussion, the costs of PNRR are not the costs of uncontrollable events.

The IOUs also state that Congress did not want the costs of uncontrollable events to cut benefits to Residential Exchange customers. BPA agrees that as a simple matter, if costs of uncontrollable events are removed from the Program Case as section 7(g) costs, this would reduce the likelihood of a section 7(b)(2) trigger and would likely increase exchange benefits, all else being equal. Again, however, the issue is whether or not a particular cost is a cost of an uncontrollable event. As BPA has established in previous discussion, the costs of PNRR are not the costs of uncontrollable events. As noted above, BPA does not dispute that the amounts charged preference customers for the costs of uncontrollable events are to be removed from the Program Case. BPA's interpretation of the Northwest Power Act, however, provides that it is logical to exclude the costs of uncontrollable events as a protection from the 7(b)(2) rate test triggering, because inclusion of the costs of discrete significant events might otherwise bias the rate test for the rate period. In other words, Congress provided protection from the costs of, for example, an act of nature that destroys or damages a resource as opposed to the cost of mitigating risks of costs that are routinely included in the normal course of business and therefore normally included in the course of ratemaking. The IOUs argue that if Congressional intent had been to remove bias, the adjustment to the test would have worked both ways, since bias can be positive or negative. *Id*. This argument is inconsistent with section 7(b)(2) of the

Northwest Power Act. Section 7(b)(2) of the Act refers to "the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, *exclusive* of the amounts charged such customers under subsection (g) of this section . . ." 16 U.S.C. 839e(b)(2) (emphasis added). The Act provides only for a subtraction of 7(g) costs, not the addition of such costs. Therefore, because Congress knew that it was going to permit only the subtraction of such costs, it is logical that Congress excluded the costs of discrete significant events which might otherwise bias the rate test for the rate period.

In summary, the IOUs argue that Congress created the 7(g) adjustments, which make it less likely for the 7(b)(2) exception to rate parity to trigger. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 27. The costs of uncontrollable events are included in 7(g) adjustments. *Id*. The IOUs argue that section 7(b)(2) makes plain that Congress did not want the benefits of Residential Exchange customers to be cut by the costs of uncontrollable events. *Id*. The IOUs also argue that BPA is violating the intent of Congress by refusing to acknowledge that the identified costs of PNRR are costs for events that are beyond BPA's control. *Id*. In response to these arguments, while the IOUs argue that Congress did not want the benefits of Residential Exchange customers to be cut by the costs of uncontrollable events, the IOUs were not the focus of the section 7(b)(2) rate test. The IOUs fail to recall the background and purpose of the section 7(b)(2) rate test, which is discussed in detail in the introduction to this chapter. The intent of 7(b)(2) is to protect preference customers, not to protect IOUs. Congress recognized that the section 7(b)(2) rate test could reduce or eliminate Residential Exchange benefits. As demonstrated in BPA's thorough analysis, the costs of PNRR are not the costs of uncontrollable events. BPA is properly implementing the intent of Congress. There are millions of "events" that occur daily and which are beyond BPA's control. It is impossible to identify each event that has occurred and which might have some impact on BPA's costs. Congress could not have intended to impose such an elusive and impractical standard upon BPA. This is confirmed by a review of the statutory context of this term. As noted previously, the 7(b)(2) rate test compares PF rates for preference customers under two scenarios: with and without the specific assumptions of section 7(b)(2). This fact suggests that Congress intended the comparison to be between rates that share the same basic costs but for the specific statutory exceptions. For this reason, uncontrollable events should be construed such that they do not exclude costs from the Program Case that are due to conditions that simply vary over time and which typically are reflected in rates. For this reason, uncontrollable events are not properly viewed as all conceivable events beyond BPA's control, but rather the discrete and significant events beyond BPA's control that differ from the continuum of changing conditions that occur in nature, business, and government and are routinely reflected in rate development.

Decision

PNRR are not costs of uncontrollable events and thus should not be excluded from the Program Case.

13.3.2 Terminated Generating Facilities

Issue

Whether the costs associated with terminated generation facilities are uncontrollable events costs to be treated as 7(g) costs in the 7(b)(2) rate test.

Parties' Positions

The IOUs argue that the termination of a generating facility constitutes an uncontrollable event, and as such, the costs of the terminated facility should be treated as 7(g) costs in the 7(b)(2) rate test. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 24-27.

BPA's Position

As noted previously, "uncontrollable events" is a statutory term that logically refers to discrete events that differ from the continuum of changing events that occur in nature, business, and government and that are routinely reflected in ratemaking. Because BPA has not identified any uncontrollable events subject to section 7(g) allocation in its rate proposal, it would be inappropriate to select any particular costs to be viewed as uncontrollable events only for the 7(b)(2) rate test. Kaptur *et al*., WP-02-E-BPA-56, at 11. While it is possible, in the proper circumstances, that the cost of an uncontrollable event could include the cost of a terminated generating facility, a deliberate, reasoned, discretionary decision to terminate a generating facility is not an uncontrollable event. Therefore, the cost of a terminated facility in such circumstances should not be considered a section 7(g) cost for purposes of the 7(b)(2) test, and no amount should be excluded from the Program Case for the cost of uncontrollable events.

Evaluation of Positions

First, it is significant that the IOUs did not file any testimony in this hearing supporting a proposal to treat the costs of terminated plants as the costs of uncontrollable events. Therefore, there is very little evidence in the record to support their proposal. The IOUs argue that while BPA noted that no witnesses from the IOUs testified whether the costs of terminated generating facilities should be included as costs of uncontrollable events, there was no need for such testimony because BPA documents clearly admitted the proposition. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 27. While the IOUs claim that there was no need for such testimony, the IOUs' failure to even mention this issue in their testimony has severely limited any record support for their arguments.

Similarly, BPA has reviewed its previous rate case RODs and no party has ever, in the history of implementation of the 7(b)(2) rate test, argued that the costs of terminated plants are costs of uncontrollable events. The IOUs cite BPA's cross-examination testimony for the proposition that including the costs of terminated nuclear plants as an uncontrollable event would greatly reduce the 7(b)(2) rate test trigger. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 25. These statements, of course, prove little. The issue is whether a particular termination of a generating facility is an uncontrollable event, not whether any event, regardless of what it is, would have an effect on the section 7(b)(2) rate trigger.

The IOUs argue that BPA has admitted in its own general contract provisions that the costs of terminated generating plants are required to be defined as costs of "uncontrollable events." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 25-26. The IOUs cite section J of the 1981 General Contract Provisions (GCPs) entitled "Allocation of certain section 7(g) Costs." Actually this is section 8(j) of the GCPs, which falls under section 8 of the GCPs, entitled "Equitable Adjustment of Rates." Most of BPA's power sales contracts were executed in 1981 and included the GCPs as an exhibit. The 1981 power sales contracts terminate on July 1, 2001. This date precedes the effective date of BPA's 2002 wholesale power rates, which will go into effect on October 1, 2001. Section 8 of the GCPs, including section 8(j), governs only the development of rates that will be in effect during the term of the 1981 power sales contracts, that is, the rates that would apply to the sales made under those contracts. Those sales terminate on July 1, 2001. Clearly, the rates being developed in the proceeding will not be in effect during the term of the 1981 contracts, and section 8 of the GCPs does not apply. To interpret this provision otherwise would preclude BPA from revising its rates until the current rates expired, leaving BPA no time to conduct a hearing to establish new rates before the new contract period had begun and requiring that BPA have no rates in effect until the hearing was completed. This would truly be an absurd result. Even assuming, *arguendo*, that the provisions were to be applicable, section 8(j) does not establish that all terminated generating facility costs are costs of uncontrollable events. GCP section 8(j) states:

> (j) Allocation of Certain Section 7(g) Costs. Costs of uncontrollable events, including but not limited to costs of a terminated generating facility and costs of experimental resources, in excess of the cost of cost effective resources, shall be allocated pursuant to section 7(g) of PL-96-501 and shall be allocated among Customers on a uniform per kW or kWh basis . . .

Cross-Examination Exh. WP-02-E-PL-16, at 136. The quoted language refers to "*[c]osts of uncontrollable events*, including but not limited to costs of a terminated generating facility . . ." The first requirement of this provision is that the event be an "uncontrollable event." BPA does not dispute that, during the time when this provision was actually in effect, it was possible for the costs of a terminated generating facility to be included in the costs of an uncontrollable event. This would occur where the termination of the facility was a result of an uncontrollable event. This is the statutory requirement of section 7(g) of the Northwest Power Act. 16 U.S.C. §839e(g). This requires review of the particular terminated generating facility to determine if its termination was a reasoned discretionary decision or if it was the result of an uncontrollable event, such as an earthquake, a flood, a terrorist act, and so on. The IOUs presented no evidence in the rate hearing that the termination of the cited nuclear projects was the result of an uncontrollable event. Clearly, the termination of a generating facility that is the result of a reasoned decisionmaking process that has taken place over a period of time, and where the decision could have been decided either way, cannot be considered an uncontrollable event. In deciding whether to terminate a generating facility, the owner must receive and analyze information about many factors relating to termination. How much would it cost? Is there a market for the power above cost? What would be the decommissioning costs? These many questions must be weighed by the decisionmaker. The decision that is informed by such analyses where there is not a required termination, but rather a discretionary decision to do so, is not uncontrollable. Uncontrollable events can cause the termination of a generating facility. The termination of a generating facility, however, is not an uncontrollable event unless the termination is caused by an uncontrollable event.

The IOUs note BPA's position that a provision of the 1981 GCPs which permitted terminated generating plants to be uncontrollable events in the proper circumstances is not dispositive, because the GCPs will expire on July 1, 2001, before the new rates take effect. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 29. The IOUs argue that this does not provide a rational basis for BPA's change in position. *Id*. The IOUs' argument, however, is not persuasive, because BPA has not changed its position on this issue. The quoted language refers to "*[c]osts of uncontrollable events*, including but not limited to costs of a terminated generating facility . . ." The first requirement of this provision is that the event be an "uncontrollable event." As noted above, BPA does not dispute that, during the time when this provision was actually in effect, as well as currently, it was possible for the costs of a terminated generating facility to be included in the costs of an uncontrollable event. This would occur where the termination of the facility was a result of an uncontrollable event.

The DSIs argue that BPA stated that GCP 8(j) is irrelevant to the meaning of uncontrollable forces in section 7(b)(2) of the Northwest Power Act. DSI Brief, WP-02-R-DS-01, at 27. This is incorrect. BPA did not say that GCP section 8(j) was irrelevant, rather that it did not govern the development of BPA's current rates. The DSIs argue that section 8 of the GCPs largely reflects the contemporaneous understanding of the Northwest parties, including BPA, that had recently completed negotiations regarding how the section 7 rate directives would be applied. *Id*. The DSIs, however, did not address this proposition in testimony and have cited no record support for this proposition. Nevertheless, as noted previously, the provision provides that the costs of a terminated generating facility can be included as the costs of an uncontrollable event where the termination of the facility was a result of an uncontrollable event. The DSIs argue that regional parties at that time feared the termination of one or more nuclear plants prior to completion. *Id*. Again, the DSIs did not address this proposition in testimony and have cited no record support for this proposition. The DSIs argue that they believe that GCP section 8(j) demonstrates that parties to the GCPs expected the costs of plants terminated prior to commercial operations were to be treated as costs of uncontrollable events under the rate directives. *Id*. This argument proves too much. If as the DSIs assert, regional parties feared the termination of one or more nuclear plants, treating the costs of such plants as the costs of uncontrollable events would have made the section 7(b)(2) rate test meaningless. BPA's preference customers, who are entitled to rate protection under section 7(b)(2), certainly would not have agreed to such a provision. The DSIs argue that they do not believe that GCP section 8(j) was intended to address the retirement of operating power plants, so the costs of Trojan and Hanford would be costs of uncontrollable events only if their premature retirement were caused by uncontrollable events. *Id*. at 28. In summary, the DSIs argue that it would be incorrect to suggest that GCP section 8(j) would become irrelevant when all the 1981 contracts have expired. *Id*. As noted above, BPA does not believe that GCP section 8(j) is irrelevant, but it does not apply to current rate development and, in any event, would support the proposition that the costs of a terminated generating facility can be included as the costs of an uncontrollable event where the termination of the facility was a result of an uncontrollable event, as BPA has previously defined.

The IOUs argue that BPA's panel testified that there have been terminated generating facilities, referring to the termination of "Trojan, Hanford, WNP-1, and WNP-3." *Id*. at 26, citing Tr. 2202. The IOUs argue that a BPA witness then said he did not know if Trojan and Hanford were terminated; "They're just shut down," Tr. 2202. In actuality, the witness stated:

> Q. Have there been any nuclear plant terminations in which BPA has had an interest?
>
> A. (Mr. Keep) My understanding is that there has been.
>
> Q. Which ones are those?
>
> A. Trojan, Hanford, WNP-1 and WNP-3, I believe – wait a minute. I do not know if Hanford and Trojan were terminated. They are just shut down. I am not sure what you mean by terminated, I guess.

In addition, the BPA witness stated:

> Q. Without further definition of terminated generating facilities, you started to identify several nuclear plants that you believe had been terminated and which BPA has an interest, including WNP-1 and WNP-3, is that right?
>
> A. (Mr. Keep) It is correct that I identified--I started to identify those plants. I am still not sure, particularly, if terminated in terms of–since I gave those four plants, two of them were actually up and operating. If terminated would mean the same thing under that case versus 2, that never–if you had never, ever said that--maybe you can not terminate something until it actually gets fired up and actually produces. So I am confused about the term "terminated," and I will end my answer with that statement of my confusion.

Tr. 2204.

In their initial brief, the IOUs argue that the cost of just two of the terminated generating facilities, WNP-1 and WNP-3, is $943,933,000 for FY 2002-2006, as shown in Cross-Examination Exhibit WP-02-E-PS-11. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 24. The cross-examination exhibit referenced was prepared by the IOUs, not prepared by BPA. The document was not presented by the IOUs in their direct testimony, where all other parties would have had an opportunity to review and respond to the document, including cross-examination of the witnesses sponsoring the document. While the IOUs cite the transcript as support for this proposition, Tr. 2205, this citation does not support their claim. The BPA witnesses did not say that the IOUs' figures were accurate. Tr. 2205. The IOUs then argue that the only reason the BPA panel could give for failing to include these costs was that "it didn't fit our perception--you have to understand our perception of an uncontrollable event is a volcano going off." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 26, citing Tr. 2206. Once again, the IOUs have mischaracterized BPA's testimony. The IOUs imply that the only type of uncontrollable event in BPA's eyes is a volcano. This, of course, is absurd. As noted previously, uncontrollable events is a statutory term that logically refers to discrete events which differ from the continuum of changing events that occur in nature, business, and government and are routinely reflected in ratemaking. This encompasses many, many events other than "a volcano going off." With regard to the foregoing issues, the IOUs have been quite selective in their use of BPA's cross-examination testimony. The questions and answers during cross-examination demonstrate the actual exchange that took place:

> Q. Now, turn to Cross-Examination Exhibit WP-02-E-PS-11, the last page. That's a different stack.
>
> A. (Mr. Keep) Okay. We did divide the piles into two piles. Yes, I have it.
>
> Q. Do you see that chart there? It is labeled costs of terminated facilities, included in BPA's proposal [reference is to table prepared by PSE, not BPA].
>
> A. (Mr. Keep) Well, I do not really agree with the term – like I said, I am not sure.
>
> Q. I am just asking if you see it.
>
> A. (Mr. Keep) I see it.
>
> Q. Very good. Now, look at the line that has a large bracket around it, with the figure 943 million – 943,933,000. Do you see that?
>
> A. (Mr. Keep) Yes.
>
> Q. Now, have you reviewed this document before today?
>
> A. (Mr. Keep) I have seen this table before today.
>
> Q. And you have reviewed it?
>
> A. (Mr. Keep) In my opinion, I have reviewed it, yes.
>
> Q. Did you talk to anybody about it?
>
> A. (Mr. Keep) I talked to Mr. Doubleday and Mr. Kaptur about it.
>
> Q. What did you talk about?
>
> A. (Mr. Keep) That we thought it was a very nice-looking table.

A. (Mr. Doubleday) And also part of the conversation was the fact that in our understanding the termination of facilities was at the administrator's discretion, and it was hard for us, personally, and with our understanding of what an uncontrollable event was, that a recent decision that took place over time and could have gone either way, could be described as an uncontrollable event.

A. (Mr. Keep) Could not be described.

A. (Mr. Doubleday) Well, yeah. That describing a decision that was made over time and could have gone either way could be--it did not fit our perception--you have to understand our perception of an uncontrollable event is a volcano going off. The administrator's decision to terminate a generating facility just didn't rise to that level to us.

A. (Mr. Keep) Especially when there is regional debate on whether it should be terminated. Seems to me that given the outcome of that debate on any one of those particular projects, they may or may not have been terminated.

Tr. at 2205-06. From the testimony above, it is clear that the 7(b)(2) rate test panel's understanding of what constituted an uncontrollable event did not include a regional debate and discretionary administrative decision that resulted in the termination of a generating facility.

The IOUs argue that there is no reason to believe Congress limited the costs of uncontrollable events to a volcano going off. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 27. As discussed above, the IOUs have mischaracterized BPA's testimony. BPA did not say that Congress limited uncontrollable events to a volcano going off. A volcano was a single example of many, many events that could comprise uncontrollable events. The IOUs argue that Congress intended to encompass the costs of all uncontrollable events. *Id.* This is not true. The analysis of whether there are costs of "uncontrollable events" that should be excluded from the Program Case must begin with an interpretation of this statutory term. The IOUs argue that the word "event" is defined as "something that happens," which is not limited in any manner whatsoever and applies to any occurrence that is beyond BPA's control. IOU Brief, WP-02-B-AC/GE/IP/MP//PL/PS-01, at 23, n. 62. This interpretation makes little sense in the context of the 7(b)(2) rate test. There are millions of "events" that occur daily and which are beyond BPA's control. It is impossible to identify each event that has occurred and which might have some impact on BPA's costs. Congress could not reasonably have intended to impose such an elusive and impractical standard upon BPA. This is confirmed by a review of the statutory context of this term. BPA must interpret the statute in a manner that is consistent with the context in which it is used, that is, the 7(b)(2) rate test. As noted previously, the 7(b)(2) rate test compares PF rates for preference customers under two scenarios: with and without the specific assumptions of section 7(b)(2). This fact suggests that Congress intended the comparison to be between rates that share the same basic costs but for the specific statutory exceptions. For this reason, uncontrollable events should be construed such that it does not exclude costs from the Program Case that are due to conditions that simply vary over time and which typically are reflected in rates. For this reason, uncontrollable events are not properly viewed as all conceivable events beyond BPA's control, but rather the discrete and significant events beyond BPA's control that differ from the continuum of changing conditions that occur in nature, business, and government and are routinely reflected in rate development. The decision whether to terminate a generating resource, where the decision could go either way, cannot be defined as uncontrollable. Therefore, there is every reason to believe that Congress would not define such a discretionary, deliberative decisionmaking process as an "uncontrollable event."

The termination of WNP-1 and WNP-3 provide evidence that a reasoned process of deliberation leading to the discretionary termination of a generating facility is not an uncontrollable event. BPA issued a ROD regarding the termination of WNP-1 and WNP-3 ("WNP-1 and WNP-3 ROD"). In that ROD, BPA conducted a thorough analysis of numerous factors relating to the discretionary decision of whether the plants should be terminated. *Id*. BPA listed a number of decision factors. *Id*. at 6. These factors included how completing WNP-1 and WNP-3 would affect BPA's competitiveness, *id.* at 6-7; BPA's need for additional resources, *id*. at 7-8; how WNP-1 and WNP-3 compare to BPA's other resource alternatives, *id*. at 8-10; and the advantages and risks of WNP-1 and WNP–3 and their alternatives, *id*. at 11-13. BPA also reviewed the alternate uses of WNP-1 and WNP–3. *Id*. at 13-14. In summary, the Administrator stated:

> On balance, it is my determination that based on the totality of factors, on the assumptions regarding the future of the plants, and on other circumstances, neither the long-term continued preservation of WNP-1 and -3 or the ultimate completion of the projects under the terms of the existing agreements is in the best interest of BPA and the region's ratepayers. Consistent with this determination, I find that the plants are not capable of producing energy consistent with prudent utility practice.

Id. at 14. Clearly, the decision to terminate WNP-1 and WNP–3 was a carefully reasoned discretionary decision in which the Administrator clearly explained the reasons for that discretionary decision. A decision of this nature is not an uncontrollable event. Indeed, this decision would be best characterized as a controllable event: a discretionary decision made by the Administrator.

The termination of PGE's Trojan Nuclear Power Plant also provides evidence that a reasoned process of deliberation leading to the termination of a generating facility is not an uncontrollable event. Within in its rate filing (UE-88) before the OPUC, PGE proved that the closure of Trojan was a "Least Cost Decision." OPUC Order No. 95-322. The company cited that "during its least-cost planning process in 1992, PGE weighed Trojan's continued viability. Among other things, PGE considered the cost of replacing the four steam generators in 1996, the loss of generation that would occur until they were replaced, and the replacement power costs such a loss would entail. In its 1992 Least-Cost Plan (LCP), PGE decided to close Trojan in 1996." *Id.* at 25. PGE proposed an earlier closure date in PGE's February 1993 update to its LCP. The foregoing shows PGE's reasoned analysis for the discretionary termination of the plant.

With regard to Hanford, there is no evidence in the record demonstrating that DOE's decision regarding its plutonium reactor was an uncontrollable event. Therefore, BPA has also concluded that this was a discretionary decision.

The IOUs note BPA's argument that terminating a generating facility is an uncontrollable event only if the termination is caused by an uncontrollable event such as an earthquake, flood, terrorist act, or other such events. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 29. Similarly, BPA noted that the shutdown of several plants in Washington was a planned controlled event that was part of a deliberative process which is characterized by or results from consideration of relevant factors. *Id*. The IOUs argue that this distinction is not rational and depends on drawing an arbitrary temporal line between cause and effect. *Id*. The IOUs argue that once the plants lost billions of dollars, contrary to everyone's intentions and expectations, BPA decided it was prudent to mothball the projects. *Id*. The IOUs, however, filed no testimony on these issues and have cited no record support for these factual allegations. The IOUs argue that the fact that BPA engaged in a deliberative process regarding how to address these uncontrollable events once they occurred does not change the fact that the costs were the result of uncontrollable events. *Id*. The IOUs, however, have not established that such costs were the costs of uncontrollable events. Where a decision to terminate a plant can go either way, the termination is clearly not an uncontrollable event. The IOUs argue that BPA would engage in the same deliberative processes following damage to a generating facility caused by earthquake, flood, or terrorist act to determine whether to terminate or try to repair or replace the facility and plan a course of action for implementing such decisions, yet BPA agrees that in such a case, if it decided to terminate a facility it would be considered the cost of an uncontrollable event. *Id*. This argument is not persuasive, because the IOUs focus solely on the conduct of a deliberative process as BPA's basis for concluding that certain costs were not the costs of uncontrollable events. It is not simply the conduct of a deliberative process but the circumstance in which a decision to terminate could go either way. Where a decisionmaker has alternative courses of action that do not require termination, termination is not an uncontrollable event, it is a controllable event.

As the IOUs describe above, deliberative processes can be associated with uncontrollable events. *Id*. However, BPA makes a distinction between a deliberative process that is associated with an uncontrollable event and a deliberative process that is not associated with an uncontrollable event. On the one hand, a deliberative process can be used to assess possible actions following an uncontrollable event, such as damage to a generating facility caused by earthquake, flood, or terrorist act. This damage is the cost of an uncontrollable event. On the other hand, a deliberative process can be used to assess the continuum of changing conditions that occur in nature, business, and government and are routinely reflected in rate development. In the first example, an individual uncontrollable event precipitated the deliberative process. In the second example, typical business review resulted in a decision to take a particular direction. Clearly, the termination of WNP-1 and -3 were one option among other viable options, and the Administrator's discretionary decision was not an uncontrollable event.

The IOUs argue that Congress certainly had no intent to protect preference utilities from the costs of terminated nuclear plants. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 7; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 30. The IOUs argue that Congress did not intend to single out residential customers of IOUs to bear the costs of these terminated nuclear plants--which would have happened even without the Northwest Power Act. *Id*. These arguments are misplaced. Preference customers are not protected from the costs of terminated generating plants. Assuming that WNP-1 and WNP-3 are terminated generating plants, the costs of such plants are defined under the Northwest Power Act, 16 U.S.C. §839a(10), and in the rate case as FBS costs. As such, these costs are used in the calculation of rates in both the Program Case and the 7(b)(2) Case of the 7(b)(2) rate test. Since these costs are in both the Program and 7(b)(2) cases of the rate test, preference customers are not protected from these costs. Since these costs are in both the Program and 7(b)(2) cases of the rate test, residential customers of IOUs are not singled out to bear these costs. The IOUs' arguments regarding Congressional intent are flawed for additional reasons. Using the overly broad IOU definition of "uncontrollable events," where the costs of every imaginable event that BPA cannot control are considered costs of uncontrollable events, would render the 7(b)(2) rate test superfluous.

The IOUs argue that no one planned for WNP-1 and WNP-3 to fail, and it was an uncontrollable event. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 30. The IOUs, however, have not established that WNP-1 and WNP-3 "failed," or that the alleged "failure" of WNP-1 and WNP-3 was an uncontrollable event. Indeed, the IOUs filed no testimony on this issue. Contrary to the IOUs' claims, as established above, it was a circumstance in which the Administrator had viable options to continue or terminate the plants and made a discretionary decision to terminate. This was hardly uncontrollable. Furthermore, there was no discrete event that caused the termination of WNP-1 and WNP-3. The IOUs argue that treatment of these costs as though they were not due to uncontrollable events is arbitrary and capricious. *Id*. To the contrary, as demonstrated by the discussion in this section, this treatment is reasonable and supported by the record and applicable law.

Congress recognized that there were ratemaking conditions when the 7(b)(2) rate test would likely trigger. Report of Senate Committee on Energy and Natural Resources, S. Rep. No. 96-272, 96th Cong., 1st Sess. 62 (1980). One of these conditions is when DSI loads are reduced relative to preference loads. *Id*. This happened first in the 1996 rate case and continues in this rate case. Another condition that makes the 7(b)(2) rate test more likely to trigger is when IOU exchange power costs become more expensive relative to BPA power costs. *Id*. This happened first in the 1996 rate case and continues in this rate case. Congress would not have defined "uncontrollable events" so broadly that ratemaking conditions that Congress itself expected to result in preference customer rate protection do not provide that protection.

In summary, the IOUs argue that including terminated plant costs as uncontrollable events would greatly reduce the section 7(b)(2) trigger amount and increase Residential Exchange benefits. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 27; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 28. This, however, is not the test that BPA must apply in conducting the 7(b)(2) rate test. BPA must determine whether specific terminated plant costs are the costs intended by Congress to constitute the costs of uncontrollable events. The terminated plant costs cited by the IOUs do not pass this test. While the IOUs argue that excluding these costs from the 7(b)(2) test is arbitrary, capricious, and a violation of law, the foregoing discussion establishes that BPA's decisions are well reasoned, supported by the record and legal analysis, and are consistent with the law.

Decision

The costs of the cited terminated generating resources are not costs of uncontrollable events and thus are not treated as 7(g) costs in the 7(b)(2) rate test.

13.4 <u>7(b)(2) Resources</u>

13.4.1 <u>FBS Resources</u>

Issue

Whether BPA has sufficient FBS resources in the 7(b)(2) Case to meet 7(b)(2) customer loads.

Parties' Positions

The DSIs argue that BPA initially stated that in the 7(b)(2) Case that "[a]dditional resources [beyond FBS] were needed to serve the 7(b)(2) customers' loads from the start of the test period." DSI Brief, WP-02-B-DS-01, at 69, citing Kaptur *et al*., WP-02-E-BPA-34, at 12. The DSIs state that BPA subsequently revised this position due to further review of BPA's 7(b)(2) Rate Test Study Documentation, concluding that FBS resources exceed the 7(b)(2) customers' loads in all years. DSI Brief, WP-02-B-DS-01, at 69.

BPA's Position

BPA agrees with the DSIs that additional resources in excess of the FBS are not needed in the 7(b)(2) Case because the FBS is sufficient to meet 7(b)(2) customers' loads. Kaptur *et al*., WP-02-E-BPA-56, at 18.

Evaluation of Positions

The DSIs argue that, in the 7(b)(2) Case, BPA must assume that the 7(b)(2) customers' loads "were served during such five-year period, with Federal base system ["FBS"] resources not obligated to other entities under contracts . . ." DSI Brief, WP-02-B-DS-01, at 69, citing section 7(b)(2)of the Northwest Power Act, 16 U.S.C. §839e(b)(2). The DSIs argue that if these FBS resources were insufficient to meet the 7(b)(2) customers' loads, then BPA may include the costs of certain, statutorily specified resources in the 7(b)(2) Case costs. DSI Brief, WP-02-B-DS-01, at 69. The DSIs argued in their direct case that additional resources in excess of FBS resources are not needed to serve 7(b)(2) customers' loads from the start of the test period, as evidenced by the size of the FBS (8,766 aMW), which exceeds the 7(b)(2) loads (from 5,423 aMW to 7,191 aMW). Schoenbeck *et al*., WP-02-E-DS/AL/VN-04(E1), at 11. BPA agrees that additional resources are not needed, because the FBS is sufficient to meet the loads of 7(b)(2) customers in the 7(b)(2) case. Kaptur *et al*., WP-02-E-BPA-56, at 18.

Decision

FBS resources are sufficient to meet the loads of 7(b)(2) customers in the 7(b)(2) Case, and BPA will not need additional resources to meet such loads.

13.4.2 7(b)(2) Case Load/Resource Balance

Issue

Whether BPA should establish a new load/resource balance in the 7(b)(2) Case to reflect the fact that resources from the 7(b)(2) resource stack are not needed to serve 7(b)(2) customers' loads and cannot be used to serve FPS contract loads.

Parties' Positions

PPC notes that BPA used the same size FBS in modeling the 7(b)(2) Case as was used to model the Program Case. PPC Brief, WP-02-B-PP-01, at 73-74. PPC notes that there are increased industrial loads in the 7(b)(2) Case. *Id.* PPC notes that in the 7(b)(2) Case, the FBS is sufficient to serve 7(b)(2) customers' (public body and cooperative customers') loads. *Id.* PPC also notes that in the 7(b)(2) Case, the FBS is not sufficient to serve all of the FPS sales served in the Program Case. *Id.* Therefore, it is appropriate to serve surplus sales in a particular order. *Id.*

BPA's Position

BPA agrees with PPC that in the 7(b)(2) Case, the FBS is not sufficient to serve all of the FPS sales served in the Program Case. Therefore, BPA must determine which FPS sales served in the Program Case will also be served in the 7(b)(2) Case. PPC Cross-Examination Exhibit, WP-02-E-PP-41. This determination requires that a separate loads and resources balance be performed in the 7(b)(2) Case.

Evaluation of Positions

The PPC states that BPA concluded that the FBS is sufficient to serve 7(b)(2) customers' loads, largely because pre-existing contracts are returning. PPC Brief, WP-02-B-PP-01, at 74. Thereafter, BPA proposed to serve surplus sales and to do so in a particular order, as provided in a BPA data response that describes an approach for determining which surplus power sales served in the Program Case would be served in the 7(b)(2) Case. *Id.*; PPC Cross-Examination Exhibit, WP-02-E-PP-41. The methodology outlined in Exhibit WP-02-E-PP-41 is a guide for modeling FPS sales in the 7(b)(2) Case, as described below.

> [T]he following is an approach for determining which FPS sales served in the Program Case would be served in the 7(b)(2) Case.
>
> The Program Case includes revenues associated with four types of FPS sales. BPA has existing contracts for three types of FPS sales: (1) FPS pre-Subscription contracts in the PNW; (2) FPS contracts at other than fully allocated cost in the PNW; and (3) FPS contracts at other than fully allocated cost in the Pacific

> Southwest. The fourth type is a forecasted sale of FPS power to an as yet undetermined set of buyers.
>
> When determining which FPS sales to model in the 7(b)(2) Case, BPA would consider Program Case FPS sales with existing contracts to be served first. In addition, within those FPS sales with existing contracts, sales to the PNW would be served first. Using these criteria, FPS sales served in the 7(b)(2) Case would be chosen in the following order: (1) FPS pre-subscription contracts in the PNW; (2) FPS contracts at other than fully allocated cost in the PNW; (3) FPS contracts at other than fully allocated cost in the PSW (including Excess Federal Power); and (4) forecasted sales of FPS power to an as yet undetermined set of buyers.
>
> Although no analysis has been performed, BPA believes all of the first two types of Program Case FPS sales mentioned above would be served in the 7(b)(2) Case. Also, a portion of the third type and none of the fourth type would be served. The reasons for this likely outcome include: (1) the DSI load is proposed to be about 819 aMW greater in the final 7(b)(2) Case than in the 7(b)(2) Case, *see* Kaptur *et al*., WP-02-E-BPA-56, at 18, line 8; (2) the size of the FBS resource is the same in both the Program and 7(b)(2) Cases because contractual obligations that might have reduced the size of the 7(b)(2) Case FBS no longer exist, *see* Section 7(b)(2) Implementation Methodology ROD, b-2-84-F-02, at 42; and (3) resources from the 7(b)(2) Case resource stack would not be used to serve FPS sales, *see* Kaptur, *et al*., WP-02-E-BPA-56, at 21, lines 13-15.
>
> The 7(b)(2) Implementation Methodology directs BPA to use ratemaking methodologies and input data in the out-years of the 7(b)(2) rate test period (FY 2007-FY 2010) that are consistent with those used for the rate case period (FY 2002-FY 2006). *See* 7(b)(2) Implementation Methodology ROD, b-2-84-F-02, at 39-40. Accordingly, FPS contracted-for sales that are in force in the first year of the 7(b)(2) Case would continue to be in force for the entire rate test period, unless the contract itself expires before that time. Also, FPS contracted-for sales that are not in force in the first year of the 7(b)(2) Case, due to insufficient FBS resources to serve them, would not be used for any year of the rate test period.
>
> The 7(b)(2) Implementation Methodology anticipated that the Surplus Firm and Nonfirm sales could be considerably different in the Program and 7(b)(2) Cases. *See* 7(b)(2) Implementation Methodology ROD, b-2-84-F-02, at 43 and 44. Any additional firm surplus in the 2002 7(b)(2) Case would be sold at a market price.

PPC Cross-Examination Exhibit, WP-02-E-PP-41.

In implementing this methodology, BPA determined that, obviously, first year FPS sales do not ensure sales for the five-year rate period. Therefore, the FPS contracts in force during each of the first five years of the 7(b)(2) rate test period will remain in force during the entire nine-year rate test period, and those contracts not served by BPA power during each of the first five years, due to insufficient FBS resources to serve them, will also not be served in the last four years of the nine-year rate test period. The first two types of FPS contracted-for sales mentioned above are fully served, along with the EFP portion of the third type of sales. EFP sales are subject to seven years' notice for termination. None of the fourth type of FPS sales is served in the 7(b)(2) Case.

Decision

For the final proposal BPA is utilizing the methodology in PPC Cross-Examination Exhibit WP-02-E-PP-41, as described above, to model FPS load in the 7(b)(2) Case and establish a new load/resource balance for the 7(b)(2) Case.

13.5 Mid-Columbia Resources

Issue

Whether BPA should include Mid-Columbia resources in the 7(b)(2) Case resource stack.

Parties' Positions

The DSIs argue that BPA cannot lawfully include Mid-Columbia resources serving regional loads in the 7(b)(2) Case resource stack. DSI Brief, WP-02-B-DS-01, at 72-75. The DSIs argue that they do not contest BPA's conclusion that the Mid-Columbia issue is moot in this case if BPA does not use resources from the resource stack to serve 7(b)(2) customers' loads. DSI Ex. Brief, WP-02-R-DS-01, at 28. The IOUs argue that BPA relied on BPA's 1996 rate case as precedent for purposes of the Mid-Columbia resources and that such use is prohibited because of a "no precedent" clause in a settlement agreement. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 102-103. The PPC argues that the Northwest Power Act permits BPA to include the Mid-Columbia resources in the 7(b)(2) Case resource stack and that BPA has properly priced such resources. PPC Brief, WP-02-B-PP-01, at 71-72.

BPA's Position

BPA believes that the Northwest Power Act permits BPA to include the Mid-Columbia resources in the 7(b)(2) Case resource stack. Kaptur *et al*., WP-02-E-BPA-34, at 13-15; Kaptur *et al*., WP-02-E-BPA-56, at 22-27. BPA believes that the Mid-Columbia resources have been properly included in the resource stack and that BPA has properly priced such resources. *Id.*

Evaluation of Positions

In the initial proposal, BPA proposed to use resources from the resource stack in the 7(b)(2) Case, which included Mid-Columbia resources, to meet specified loads. Kaptur *et al*., WP-02-E-BPA-34, at 12. In BPA's rebuttal testimony, however, BPA recognized that additional resources in excess of the FBS were not needed to meet 7(b)(2) customers' loads; therefore, it was unnecessary to use any resources from the 7(b)(2) Case resource stack in conducting the 7(b)(2) rate test. Kaptur *et al*., WP-02-E-BPA-56, at 18-19. Because BPA did not propose to use resources from the 7(b)(2) Case resource stack, including the Mid-Columbia resources, in conducting the 7(b)(2) rate test, this issue would not affect the development of BPA's wholesale power rates in this proceeding and need not be addressed at this time.

Decision

The issue of whether BPA should include Mid-Columbia resources in the 7(b)(2) Case resource stack is moot, because BPA will not use any resources from the resource stack, including Mid-C resources, to meet 7(b)(2) customers' loads.

13.6 Demand Elasticity

Issue

Whether BPA should increase the amount of "within and adjacent" DSI loads above what was included in the initial proposal 7(b)(2) Case.

Parties' Positions

The IOUs urged BPA to increase the "within and adjacent" loads in the 7(b)(2) Case above the amount in BPA's initial proposal, based upon the theory that DSI loads would naturally increase in the 7(b)(2) Case as a result of elasticity of demand, which they argue is a "natural consequence" of the statutory assumptions. Hoff *et al.*, WP-02-E-AC/GE/IP/MP/PL/PS-03, at 28-29.

The DSIs argued that section 7(b)(2)(A) of the Northwest Power Act is not intended to augment the 7(b)(2) public and cooperative loads by arbitrarily transferring to utilities in the 7(b)(2) Case DSI loads that are in existence but not served by BPA in the Program Case. DSI Brief, WP-02-B-DS-01, at 69-72; DSI Ex. Brief, WP-02-R-DS-01, at 28-30.

BPA's Position

BPA agrees with the IOUs that the "within and adjacent" DSI loads in the 7(b)(2) Case should be increased beyond the amount used in BPA's proposal. Kaptur *et al*., WP-02-E-BPA-56, at 17-18.

Evaluation of Positions

During the hearing, the IOUs asked BPA to increase the "within and adjacent" loads in the 7(b)(2) Case above the amount in BPA's proposal, arguing that DSI loads would naturally increase in the 7(b)(2) Case as a result of elasticity of demand, which is a "natural consequence of the Northwest Power Act's section 7(b)(2) assumptions." Hoff *et al*., WP-02-E-AC/GE/IP/MP/PL/PS-03, at 28-29. In its rebuttal testimony, BPA staff agreed with the IOUs, noting that because the Implementation Methodology recognizes elasticity of demand as one of the natural consequences of the five section 7(b)(2) assumptions, BPA would increase the DSI within or adjacent load above the 847 aMW used in the proposal. Kaptur *et al*, WP-02-E-BPA-56, at 17. *See also* Section 7(b)(2) Implementation Methodology, b-2-84-F-02, at 19-29; and BPA's Legal Interpretation of Section 7(b)(2), b2-84-FR-03, at 7-8. BPA staff then calculated the difference between the 1,947 aMW of DSI load that BPA is forecasting it will serve in FY 2001 and the 990 aMW that BPA proposed to serve in the Program Case, and multiplied the difference by .856 (the within or adjacent factor). Kaptur *et al*, WP-02-E-BPA-56, at 18. BPA staff concluded that 819 aMW of additional DSI load should be treated as part of the general requirements of 7(b)(2) customers for purposes of the 7(b)(2) Case. *Id.*

The DSIs argue that section 7(b)(2)(A) is not intended to augment the 7(b)(2) customers' loads by arbitrarily transferring to utilities in the 7(b)(2) Case DSI loads that are in existence but not served by BPA in the Program Case. DSI Brief, WP-02-B-DS-01, at 70-71. This, however, is not what BPA has done. BPA has not arbitrarily transferred DSI loads to utilities in the 7(b)(2) Case. Instead, BPA has determined, as discussed in greater detail below, that the power cost differences in the Program and 7(b)(2) Cases alone are sufficient to make the forecasted differences in DSI loads reasonable. The DSIs argue that elasticity addresses price-induced load growth, and the additional amount of DSI load proposed to be added has nothing to do with elasticity of demand. *Id.* To the contrary, again as discussed below, the DSI load proposed to be added is price-induced load growth.

The DSIs argue that the only way BPA would serve the additional load in the 7(b)(2) Case is if BPA were to change its policy on service to the DSIs. *Id.* at 71. The DSIs argue that a change in policy, to serve load in the 7(b)(2) Case that BPA refuses to serve itself and expects to be served by other entities in the Program Case, is not a permitted change in assumptions. *Id.* BPA disagrees with the DSIs' argument that a policy change is necessary for a separate 7(b)(2) Case DSI load forecast. As discussed in more detail below, it is the power cost differences in the Program and 7(b)(2) cases alone that are sufficient to make the forecasted differences in DSI loads reasonable. No change in BPA policy is needed.

The DSIs argue that only if BPA can conclude, based on the record, that changes to its rates cause an increase in DSI load is the natural consequence of elasticity of demand relevant at all. DSI Brief, WP-02-B-DS-01, at 71. As explained below, however, BPA has demonstrated that, based on the record, changes to its rates cause an increase in DSI load. The DSIs argue that there is no relationship between differences in power costs in the Program Case and the 7(b)(2) Case and the additional 819 aMW of DSI load. *Id.* BPA disagrees with the DSIs. The rate case record demonstrates, as discussed in more detail below, that a separate DSI load forecast for the 7(b)(2) Case, with additional DSI load served by the public and cooperative utilities, is reasonable.

The DSIs argue that BPA plainly does not intend to serve the additional 819 aMW at an IP rate, and because the proposed NR rate is sufficiently above the expected market price of power, BPA does not expect to serve the load at NR. *Id.* Therefore, the DSIs argue that the additional load is not "served by the Administrator" as required by section 7(b)(2)(A) of the Northwest Power Act. *Id.* BPA agrees that the 819 aMW is not served by BPA in the Program Case. However, the rate case record shows that a large portion of the 819 aMW would likely be idle capacity in the Program Case, as discussed in greater detail below, and can be defined as price-induced load growth in the 7(b)(2) Case. In addition, the substantial rate difference between the Program Case

IP rate and the 7(b)(2) Case PF rate indicates that the 990 aMW that is "served by the Administrator" in the Program Case would likely increase due to elasticity of demand in the 7(b)(2) Case. BPA has used the 819 aMW as a reasonable proxy for the added DSI load in the 7(b)(2) Case. This increase is caused by the assumed idle capacity in the Program Case coming on-line in the 7(b)(2) Case, as well as price-induced increases to the DSI load "served by the Administrator" in the Program Case.

BPA's forecast of service to the DSIs in FY 2001 is 1,947 aMW. Kaptur *et al.*, WP-02-E-BPA-56, at 18. BPA's Program Case forecast of service to the DSIs in FY 2002 is 990 aMW. *Id.* at 18. The DSIs will have access to 1,947 aMW of BPA power at the IP rate on September 30, 2001, and a day later they will have access to 990 aMW of BPA power at the IP rate, according to the assumptions in the Rate Design Step of the RAM. The DSI load no longer served at the IP rate in the Program Case on October 1, 2001, is 957 aMW, the difference between the September 30, 2001, amount of 1,947 aMW and the 990 aMW. This former BPA IP rate load could only be served by expensive market purchases or resources. Therefore, BPA assumes that a large portion of the 957 aMW of DSI load not served at the IP rate in the Program Case will become idle capacity due to high cost of non-IP rate power in the Program Case.

To estimate the cost of power facing the DSI load that is not being served by BPA in the Program Case, BPA first considered its own market price forecast for five-year flat-block purchases, 28.1 mills/kWh. Oliver *et al.*, WP-02-E-BPA-20, at 4. However, 28.1 mills is the expected average price for a limited amount of purchases, 1,562 aMW. *Id.* at 5. Purchases were assumed to be made in 250 aMW blocks, the first of which are expected to be less expensive than the 28.1 mill average, while later 250 aMW blocks are expected to approach the 32.2 mill MCA marginal cost. *Id.* at 4. If an additional 957 aMW of market purchases were assumed to be made by the DSIs in the Program Case, over and above those already made by BPA, the average price of the DSI purchases would exceed BPA's forecasted 28.1 mills and would likely approach the 32.2 mill MCA marginal cost. Power costs this high would put smelter loads at risk. Alcoa *et al*. argue that even at a 28 mill market price, 68 percent of smelter loads are at risk. Speer *et al.*, WP-02-E-AL/VN/EG-01, at 5. As noted above, later purchases will approach the 32.2 mill level. Oliver *et al.*, WP-02-E-BPA-20, at 4. The likely 30 to 32 mill market price for the last few 250 aMW blocks would certainly put a far larger percentage than 68 percent of DSI smelter loads at risk.

On October 1, 2001, the within and adjacent portions of the 990 aMW DSI load served in the Program Case will be served by public and cooperative utilities in the 7(b)(2) Case. A large percentage, certainly greater than 68 percent, of the within and adjacent portions of the 957 aMW that is considered to be idle capacity due to high market prices in the Program Case can be served by public and cooperative utilities in the 7(b)(2) Case at the 7(b)(2) Case PF rate. The undelivered 7(b)(2) Case PF rate in FY 2002 is 15.88 mills/kWh. Section 7(b)(2) Rate Test Study Documentation, WP-02-E-BPA-06A, at 74. The idle DSI capacity assumed to be induced by high power cost (30-32 mills/kWh) in the Program Case can be served as load growth assumed to be induced by low power cost (15.9 mills/kWh) in the 7(b)(2) Case.

The rate case record shows that the undelivered IP rate in the Program Case in FY 2002 is 20.98 mills/kWh. *Id.* at 40. The over five mills/kWh difference between the rates under which the DSIs can purchase power in the Program Case, 20.98 mill/kWh, and under which they can purchase power in the 7(b)(2) Case, 15.9 mills/kWh, would induce elasticity of demand load growth in the 7(b)(2) Case DSI load. BPA has used the rate case record to forecast an additional 819 aMW of DSI load placed on the public and cooperative utilities in the 7(b)(2) Case, over and above the 990 aMW of DSI load in the Program Case. This increase is caused by the assumed idle capacity in the Program Case coming online in the 7(b)(2) Case, as well as price-induced increases to the DSI load "served by the Administrator" in the Program Case.

The DSIs argue that the 7(b)(2) rate test directs the Administrator to calculate 7(b)(2) Case costs as if the general requirements of preference customers "had included during such five-year period the direct service industrial customer loads which are – *served by the Administrator* and located within or adjacent to the geographic boundaries of such [customers]" (emphasis added). DSI Ex. Brief, WP-02-R-DS-01, at 29. The DSIs argue that the Draft ROD acknowledged that according to the assumptions in the Rate Design Step of the RAM, BPA's policy decision to serve no more than 990 aMW of DSI load at statutory rates after September 30, 2001, means that the Program Case forecast of service to the DSIs in FY 2002 is 990 aMW. *Id*., citing Draft ROD, WP-02-A-01, at 13-41. The DSIs note the Draft ROD declares a large portion of the remaining DSI load (the load assumed not to be served by the Administrator in the Program Case) will stand idle due to the high cost of non-IP rate power in the Program Case, citing Draft ROD, WP-02-A-01, at 13-42. *Id*. The DSIs argue that whether or not load served by the Administrator in the Program Case might operate differently depending on the power price such load might have to bear, it remains load not served by the Administrator in the Program Case. *Id*. The DSIs argue that BPA's load obligations to the DSIs in this case are established by policy and contract, and therefore the price elasticity of that portion of the DSI load that BPA is not proposing to serve in the Program Case is irrelevant; it is not load served by the Administrator, and BPA cannot assume that it is transferred to public utilities and offered at below-market rates. *Id*. The DSIs note that the entire DSI load served by the Administrator is served under take-or-pay contracts, and thus the 990 aMW served by the Administrator in the Program Case cannot change even if the IP rate in the Program Case and the 7(b)(2) costs in the 7(b)(2) Case differed substantially. *Id*. at 30.

BPA disagrees with the DSIs' argument that additional DSI load cannot be added to the 7(b)(2) Case. While BPA's Implementation Methodology recognizes that the within and adjacent portion of the DSI load served by the Administrator in the Program Case will be included in the 7(b)(2) customer load in the 7(b)(2) Case, the Implementation Methodology expressly recognized elasticity of demand as one of the natural consequences of the five section 7(b)(2) assumptions. Implementation Methodology, at 19-29. The Implementation Methodology describes the concept of natural consequences:

> Natural consequences, also referred to as secondary effects, result from the relationship of the 7(b)(2) case to the program case: the two cases will be modeled using the same underlying premises and ratemaking procedures. Implementing the five assumptions listed in section 7(b)(2) in the 7(b)(2) case may produce results different from those in the program case when using the same underlying premises and ratemaking procedures used in the program case. These differing results are the natural consequences of the 7(b)(2) assumptions. *See* BPA Legal

> Interpretation, 49 Fed. Reg. 23998, 2400-2401 (1984), which contains a full discussion of the legal basis for the recognition of such secondary effects.

Implementation Methodology, at 19. BPA's Legal Interpretation of Section 7(b)(2), 49 Fed. Reg. 23,998 (1984), provides further definition of these natural consequences:

> The Administrator will exercise [her] discretionary authority in the following manner. Except for the assumptions specified in section 7(b)(2), all underlying premises will remain constant between the program case and the 7(b)(2) case. Assumptions not specified by the statute will not be considered. The natural consequences, however, of the 7(b)(2) assumptions will be given full recognition in the modeling of the 7(b)(2) customers' power costs in the 7(b)(2) case. This general approach will allow the 7(b)(2) case to be modeled under the same accepted ratemaking techniques used in the program case. This approach will also avoid the modeling of a hypothetical world that attempts to reflect in extreme detail what would have occurred had the Northwest Power Act not been enacted.
>
> . . .
>
> Legislative history also supports including the natural consequences or unavoidable secondary effects of the assumptions listed in the Northwest Power Act. In particular, in addressing reserve benefits, Appendix B to the Report of the Senate Committee on Energy and Natural Resources provides that in addition to costs specifically described in sections 7(b)(2)(B) and (D), the Administrator is to consider "any other general system operating costs, including reserves . . ." Appendix B at 58.
>
> As an illustration of the natural consequences referred to above, BPA has identified three secondary effects of the five assumptions found in section 7(b)(2). These effects involve demand elasticities, surplus levels and nonfirm energy markets. The secondary effects must be included in section 7(b)(2) methodologies as natural consequences of the five assumptions in section 7(b)(2) on the results of underlying premises that are held constant between the program case and the 7(b)(2) case. For example, implicit in the function of section 7(b)(2) is the possibility that electricity prices may be different under the assumptions contained in section 7(b)(2). Therefore, it could be appropriate to reflect the effects of different price projections in load forecasts used for the two cases. Ignoring these price effects would require adopting a new assumption, not specified in the statute, that the price elasticity of electricity demand for the 7(b)(2) customers is zero (in effect, adding something like this to the statute: "costs calculated pursuant to subsection (A)-(E) of this paragraph shall give only partial effect to the assumptions in those subsections"). An assumption of this nature is theoretically and empirically unjustified and would be inconsistent with the structure of the models used to develop load forecasts for the relevant rate case.

BPA's Legal Interpretation of Section 7(b)(2), at 7-8 (footnotes omitted). More notably, however, the Implementation Methodology expressly addresses the issue raised by the DSIs, noting that DSI loads not in operation due to economic conditions under the Program Case can be in operation in the 7(b)(2) Case. The Implementation Methodology provides:

> DSI loads will be input to the rate test model on a plant-by-plant basis. The plants will be flagged to indicate whether they are within or adjacent to the service area of any 7(b)(2) customer based on the list contained in Appendix B. If a DSI leaves the region or is no longer served by BPA, its loads will not be assumed to transfer from BPA service to utility service. Any DSI served by a utility other than BPA in the program case will continue to be served by that utility in the 7(b)(2) case. *However, if a DSI plant is forecast not to operate due to economic conditions under the program case, but projected electric rates are low enough under the 7(b)(2) case to allow a forecasted level of operation, then the load associated with that level of plant operation may be included in the 7(b)(2) case load forecast.*

Implementation Methodology, at 41 (emphasis added). Therefore, BPA can increase the DSI within or adjacent load above the 847 aMW used in the initial proposal. Kaptur *et al*, WP-02-E-BPA-56, at 17. *See* Section 7(b)(2) Implementation Methodology, b-2-84-F-02, at 19-29; and BPA's Legal Interpretation of Section 7(b)(2), b-2-84-FR-03, at 7-8. A separate load forecast can be performed for the 7(b)(2) Case if the monetary amounts in the Program Case and 7(b)(2) Case differ significantly. *See* Section 7(b)(2) Implementation Methodology, b-2-84-F-02, at 23. As one of the natural consequences of the five section 7(b)(2) assumptions and for the reasons discussed above, elasticity of demand can reasonably be assumed to produce a DSI forecast for the 7(b)(2) Case that is larger than the amount of DSI load served by the Administrator in the Program Case. In addition, those DSI loads not served by the Administrator in the Program Case can reasonably be assumed to be idle. In the 7(b)(2) Case world, with its low wholesale rates to public body utilities, that idle capacity would be induced to become active again.

The DSIs argue that often the stated factual basis for resolving one issue is directly contradictory to the factual finding made to resolve other issues. DSI Ex. Brief, WP-02-R-DS-01, at 2. The DSIs also argue that the Draft ROD, for example, justifies the manner in which one sub-issue relating to the 7(b)(2) rate test was modeled by declaring that most DSI plant load not served by BPA will become idle due to the high cost of market-priced power, but justifies the adequacy of the Variable (cost-based indexed IP) rate for DSIs on the ground that at expected aluminum prices, DSI plants face no threat to their operation. *Id.* BPA disagrees with the DSIs' argument that the factual findings concerning DSI plant operations in the 7(b)(2) rate test and the cost-based indexed IP rate for DSIs are contradictory. The two findings occur in very different worlds. The DSI cost-based indexed IP rate is a Subscription Strategy rate and is analyzed from the perspective of BPA's expectations about actual Subscription sales to the DSIs. The section 7(b)(2) rate test 7(b)(2) Case DSI load forecast is analyzed from the perspective of the Rate Design Step in the RAM, which does not contemplate the Subscription Strategy. In addition, while the DSI cost-based indexed IP rate will actually be offered to DSI customers, the

7(b)(2) Case is an artificial world that is modeled following specific directives in the Northwest Power Act.

In the section 7(b)(2) rate test world, the 7(b)(2) Case DSI load forecast assumes a 70 cents/lb. aluminum price. This price is the mid-point between the minimum price of 66 cents/lb. and the maximum price of 74 cents/lb. Miller *et al.*,WP-02-E-BPA-46, at 6. In the section 7(b)(2) rate test Program Case, the DSIs can purchase 990 aMW of BPA power at 25.35 mills/kWh. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 82. As discussed above, purchases beyond the 990 aMW are likely to be purchased at 30-32 mills/kWh. Oliver *et al*., WP-02-E-BPA-20, at 4. In addition, the RAM modeling does not model the effects of a cost-based indexed IP DSI rate. The moderate aluminum price combined with a relatively high 7(b)(2) rate test cost of electricity resulted in the assumption that a large amount of DSI load in the section 7(b)(2) rate test Program Case would be idled.

On the other hand, the cost-based indexed IP rate analysis assumed a 74 cent/lb. aluminum price mid-point. The analysis also assumed DSI power purchases from BPA of as much as 1,300 aMW at 23.5 mills/kWh, Miller *et al*., WP-02-E-BPA-21, at 4; with additional purchases at 28.1 mills/kWh, Oliver *et al*., WP-02-E-BPA-20, at 7. The higher aluminum price and the lower average cost of purchased power results in an assumption that there is little threat to DSI operations. In summary, where the DSIs saw a contradiction, BPA actually was consistent. The assumptions used in the 7(b)(2) rate test world were reasonable for that world. The assumptions in the DSI Variable rate analysis were reasonable for that purpose. In these examples, low aluminum prices and high energy prices produced a different result than did high aluminum prices and low energy prices. These are not contradictory results as the DSIs allege. They are just two different results.

Decision

BPA has increased the amount of "within and adjacent" DSI loads above what was included in the initial proposal 7(b)(2) Case. BPA's forecast of an additional 819 aMW of price-induced DSI load in the 7(b)(2) Case is reasonable and supported by the record.

13.7 BPA's Rate Development Process

Issue 1

Whether BPA's rate development process is cohesive and produces an end result that properly implements BPA's policy goals and provides residential and small farm customers proper benefits.

Parties' Positions

PGE argues that no one within BPA has exerted overall control in the rate development process to ensure that the end result of that process achieves the agency's policy goals. PGE Brief, WP-02-B-GE-01, at 2-3. PGE argues that BPA must measure its proposal against BPA's Subscription Strategy goals. *Id*. at 1. PGE argues that BPA's rate development process has produced an end result that does not implement BPA's Subscription Strategy goal of spreading the benefits of the FCRPS widely. *Id.*

<u>BPA's Position</u>

BPA reviewed BPA's policy goals during the rate development process. BPA's proposed rates properly implement the Subscription Strategy goal of spreading the benefits of the FCRPS widely. *See* Burns *et al.,* WP-02-E-BPA-08, at 7.

<u>Evaluation of Positions</u>

Without citation to authority, PGE argues that no one within BPA has exerted overall control in the rate development process to ensure that the end result of that process achieves the agency's policy goals. PGE Brief, WP-02-B-GE-01, at 2-3. As discussed in greater detail below, there are certain staff functions, *i.e*., load and resource forecasts, that are technical tasks that reflect the expert analysis of BPA's specialists in those areas. Policy guidance is reflected generally by previous BPA administrative decisions that are reflected in the initial assumptions for an analysis; however, policy guidance is generally unnecessary in performing such studies. While certain BPA employees may not review the end result of the overall process, this does not mean that there are not BPA employees who do review BPA's proposed rates to compare those rates to BPA's policy goals. This is a general review that does not dictate that staff change their technical analyses, but rather compares the results of BPA's proposed rates to BPA's policies. BPA determined that BPA's proposed rates satisfy its policy goals. Ultimately, this is an evaluation made by the Administrator after review of the administrative record.

PGE argues that BPA's rate development process is fragmented and argues that BPA workgroups operated to a considerable extent in isolation from each other, and inputs and assumptions were not measured against BPA's policy goals along the way. PGE Brief, WP-02-B-GE-01, at 2-3. As noted above, it is not necessary to compare each extremely technical analysis performed by expert BPA staff with BPA's policy goals. BPA believes that PGE's argument may be premised on a misunderstanding of the manner in which BPA develops rates. BPA's ratemaking process is complex and uses highly technical studies and data. The various workgroups that produce the technical studies that are part of the rate case record are made up of skilled specialists. When developing, for example, load and resource information, BPA develops the information in the proper technical manner. BPA, at that point, has no need to refer to policy guidance. These are simply technical analyses. The 7(b)(2) rate test workgroup, and the workgroup responsible for calculating posted rates for this rate case, properly relied on many other workgroups in BPA to furnish studies and data. Kaptur *et al.*, WP-02-E-BPA-56, at 7-8. The 7(b)(2) and rates workgroups had neither the knowledge nor the inclination to second guess the actual experts in their fields that provided their technical information to the section 7(b)(2) and rates workgroups, nor alter the data they received from other specialists in order to arrive at some predetermined or biased outcome. The 7(b)(2) and rates workgroups used the data provided by other experts within BPA and did their analyses by following their understanding of the Northwest Power Act and the Section 7(b)(2) Implementation Methodology ROD. Tr. 2163.

BPA's rate analyses are technical matters that produce technical results and are not policy issues. BPA managers have not directed these groups to produce specific predetermined results. Tr. 125. This is the proper way to develop rates. To suggest that each technical issue addressed by BPA must be compared to BPA policy makes little sense. Nevertheless, a review of BPA's 2002 power rates demonstrates that BPA has achieved its policy goals. With regard to the goal of spreading the benefits of the FCRPS as broadly as possible, with special attention given to the residential and rural customers of the region, BPA has achieved this goal, in part, by proposing to offer settlements of the REP (which include a proposed 1,800 [1900] aMW of benefits in power and money) for which BPA has proposed the RL and PF Exchange Subscription rates. Furthermore, BPA's forecasted Residential Exchange benefits to the IOUs total approximately $37 million per year during the rate period. Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 91. In providing special attention to residential and rural customers of the IOUs and giving them an additional option in access to Federal benefits, BPA forecasted Exchange settlement benefits to the IOUs that total approximately $140 million per year during the rate period. Tr. 122. To suggest that BPA is not giving special attention to the region's residential and rural customers of IOUs is simply incorrect.

Similarly, with regard to the goal of avoiding rate increases through a creative and business-like response to markets and additional aggressive cost reductions, BPA proposed rates to PF Preference customers that have avoided a rate increase and thereby provided rate stability. With regard to allowing BPA to fulfill its fish and wildlife obligations while assuring a high probability of U.S. Treasury payment, BPA proposed rates that allow for the recovery of the costs of BPA's fish and wildlife obligations and which achieve an 88 percent TPP. With regard to providing market incentives for the development of conservation and renewables as part of a broader BPA leadership role in the regional effort to capture the value of these and other emerging technologies, BPA proposed the C&R Discount and the acquisition of additional conservation. Therefore, BPA is aware of its policy goals in designing rates and believes that the 2002 power rates satisfy those goals.

<u>Decision</u>

BPA's rate development process is cohesive, and the 2002 power rates implement BPA's Subscription Strategy goals.

<u>Issue 2</u>

Whether BPA used proper inputs and assumptions in its conduct of the 7(b)(2) rate test and whether those assumptions were tied to those used in BPA's 1996 rate case.

<u>Parties' Positions</u>

PGE argues that BPA incorrectly used the inputs and assumptions borrowed from the 1996 rate case to perform the 7(b)(2) rate test, and that correcting these inputs and assumptions would yield higher Residential Exchange benefits. PGE Brief, WP-02-B-GE-01, at 4-5. The IOUs argue that in 1996, BPA changed various 7(b)(2) rate test assumptions in order to cut rates to DSI customers and keep them from leaving BPA. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 16. The IOUs argue that because BPA's 7(b)(2) panel did not go back and correct the assumptions BPA made in the 1996 7(b)(2) rate test to cut rates to the DSIs, the end result is reduced REP benefits. *Id.* The DSIs argue that the IOUs' claim that the 7(b)(2) rate test was manipulated to pay for a lower rate for the DSIs is baseless. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-06, at 14-15.

<u>BPA's Position</u>

The 7(b)(2) rate test in 1996 was properly conducted by BPA. Boling and Doubleday, WP-02-E-BPA-53, at 12-13. BPA is not relying on BPA's 1996 rate case decisions as binding and has evaluated all 7(b)(2) issues in the current proceeding. If certain positions are similar to previous rate cases, going back to 1985, it is because BPA believes that such positions are correct. *Id*. at 14. BPA did not change various 7(b)(2) rate test assumptions in 1996 in order to cut rates to DSI customers and keep them from leaving BPA. Kaptur *et al*., WP-02-E-BPA-56, at 2-5. Residential Exchange benefits are calculated by comparing a utility's ASC with BPA's PF Exchange Program rate. *See, e.g*., Boling and Doubleday, WP-02-E-BPA-30, at 2.

<u>Evaluation of Positions</u>

PGE argues that the workgroup that performed the 7(b)(2) rate test performed no calculation of the amount of Residential Exchange benefits the residential and small farm customers of the IOUs would receive, compared to the benefits provided to BPA's other residential customers through access to power at the PF Preference rate. PGE Brief, WP-02-B-GE-01, at 4-5, citing Tr. 2111. PGE has misrepresented BPA's cross-examination testimony. The cited testimony concerning possible calculations performed by the 7(b)(2) panel consists of one question and answer:

> Q. (Mr. Marshall) Have you done any calculations of the percentages of benefits to the residential rural customers of Northwest IOUs under BPA's settlement proposal?
>
> A. (Mr. Keep) No, I have not.

Tr. 2111.

PGE's argument above refers to benefits under the traditional REP, while the cited question and answer above refers to benefits under BPA's settlement proposal. The calculations done by the 7(b)(2) panel result in the determination of the 7(b)(2) rate test trigger amount. That trigger amount has some impact on the level of the PF Exchange Program rate. The level of the PF Exchange Program rate has some impact on the amount of benefits under the traditional REP. However, the calculations done by the 7(b)(2) panel have no impact on the level of BPA's settlement proposal benefits. The 7(b)(2) panel would not, as a normal part of their duties, calculate traditional REP benefits, nor would they compare those benefits with the benefits enjoyed by other customer groups.

PGE argues that the 7(b)(2) panel did not independently consider the objectives of the Northwest Power Act with regard to benefits under the REP, and did not examine the end result produced by their calculations of the 7(b)(2) test. PGE Brief, WP-02-B-GE-01, at 5. The IOUs fail to recognize, however, that the determination of the objectives of the Northwest Power Act is a legal matter. Because the 7(b)(2) witnesses are not lawyers, they would not be expected to provide a legal analysis of the objectives of the Northwest Power Act. The witnesses, however, do have their own understanding of the Northwest Power Act. As noted below, BPA believes that BPA's implementation of the 7(b)(2) rate test in the current rate case, the end result of the rate case, and BPA's 2002 power rates are perfectly consistent with the Northwest Power Act and the legislative history of the Northwest Power Act. In addition, as discussed in ROD chapter 14, there is no end results test that is applicable to BPA's ratemaking. Furthermore, BPA has been developing rates under the Northwest Power Act for nearly 20 years. In each rate case BPA has conducted, BPA has implemented the same statutory rate directives as in the previous rate case, and subject to the changes in the rate directives beginning in 1985. In addition, BPA reviewed the Northwest Power Act and its legislative history in developing BPA's Legal Interpretation of Section 7(b)(2) in 1984, b-2-84-FR-03. BPA also reviewed the Northwest Power Act and its legislative history in developing BPA's Section 7(b)(2) Implementation Methodology in 1984, b-2-84-F-02. BPA also has conducted the 7(b)(2) rate test in every rate case since 1985, except in the cases where the rate case was settled and the test was not performed. In summary, BPA is extremely familiar with the 7(b)(2) rate test and the Congressional intent behind the test. This makes a comparison of the results of the rate test with Congressional intent an inherent part of the rate test. BPA's extensive review of the legislative intent of the 7(b)(2) rate test is found throughout this chapter of the ROD. After reviewing BPA's implementation of the 7(b)(2) rate test in the current rate case, the end result of the rate case and BPA's 2002 power rates are perfectly consistent with the Northwest Power Act, the legislative history of the Northwest Power Act, and other applicable rules.

PGE and the IOUs argue that BPA's 7(b)(2) panel felt constrained to calculate the 7(b)(2) rate test in the same manner that the test was performed in the 1996 rate case. PGE Brief, WP-02-B-GE-01, at 5; IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 16. BPA disagrees. In making this argument, the IOUs cite Kaptur *et al*., WP-02-E-BPA-56, at 5, 7-8. *Id*. In BPA's review of page 5 of the cited testimony, BPA can find no statement that BPA's witnesses felt constrained by manner that the test was performed in the 1996 rate case. In reviewing pages 7 and 8 of the cited testimony, BPA also can find no statement that BPA's witnesses felt so constrained. Indeed, pages 7 and 8 do not even reference 1996. While BPA clearly did not feel constrained to follow BPA's 1996 rate test, in conducting the rate test it is likely that BPA's positions on many issues will be the same as in BPA's previous rate cases, not because BPA is relying on 1996 decisions or assumptions, but rather because the same issues arise in each rate case and BPA has been conducting the 7(b)(2) rate test since 1985. BPA has implemented consistent interpretations of section 7(b)(2), the Section 7(b)(2) Implementation Methodology, and BPA's Legal Interpretation of Section 7(b)(2). BPA's understanding of the Northwest Power Act, the Section 7(b)(2) Implementation Methodology ROD, and BPA's Legal Interpretation of Section 7(b)(2) can be traced back to rate cases in the mid-1980s, not BPA's 1996 rate case. Tr. 2149-50; Tr. 2218. BPA still conducts independent evaluations of each issue, however, as reflected in BPA's studies, documentation and testimony filed in this rate case. This information is specific to this rate case, and is not relying on any previous rate case.

Because these issues are analyzed for each rate case, BPA's studies, documentation and testimony ensure that BPA's determinations are accurate. There are many specific rules that BPA must follow in developing rates. These rules leave little room for discretion on BPA's part. The results of the 7(b)(2) rate test reflect BPA's best determination of the issues that comprise the rate test. As noted in BPA's testimony, "[e]ach issue regarding the 7(b)(2) rate test is considered and determined on its merits. Similarly, other rate case issues must be determined on their merits." Boling and Doubleday, WP-02-E-BPA-53, at 18.

PGE and the IOUs argue that BPA made several adjustments to the 1996 7(b)(2) test to ensure that BPA's rates were sufficiently competitive to retain its DSI customers. PGE Brief, WP-02-B-GE-01, at 5; IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 16. PGE argues that even though in the current rate case BPA does not face these same competitive pressures, BPA has not corrected the adjustments made to the 7(b)(2) test in 1996. PGE Brief, WP-02-B-GE-01, at 5. The IOUs also argue that because BPA's 7(b)(2) panel did not go back and correct the assumptions BPA made in the 1996 7(b)(2) rate test to cut rates to the DSIs, the end result is reduced REP benefits. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 16. BPA disagrees with these arguments. PGE and the IOUs first allude to major changes made in BPA's 1996 7(b)(2) rate test assumptions, while explicitly mentioning only three changes they contend that BPA should make in the current case. PGE Brief, WP-02-B-GE-01, at 5-11; IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 14-29. First, as noted previously, BPA did not make adjustments to the 1996 7(b)(2) rate test in order to retain its DSI customers. Upon further review, however, the adjustments alleged by the IOUs to have occurred in 1996 were not made again in the current rate case. The first change proposed by the IOUs is to treat conservation costs as FBS resource costs. After review of BPA's previous rate case RODs, BPA knows it has never treated conservation costs as FBS costs, not in BPA's 1996 rate case or any other previous rate case. Similarly, parties to previous rate cases have never even proposed that conservation should be treated as an FBS resource. Obviously, this cannot be an adjustment that BPA is continuing. The second change proposed by the IOUs is to define the term "uncontrollable events" to include PNRR and the termination of generating facilities. As with the previous discussion of conservation costs, after review of BPA's previous rate case RODs, BPA knows that it has never defined PNRR or the costs of terminated thermal generating plants as the costs of "uncontrollable events," not in the 1996 rate case or any other previous rate case. Similarly, parties in previous rate cases have never proposed that PNRR or the costs of terminated thermal generating plants be defined as the costs of "uncontrollable events." Since these changes being proposed by the IOUs are not associated with the way the 1996 7(b)(2) rate test was conducted, BPA cannot be continuing any alleged adjustment on these issues. The third change proposed by the IOUs involves the way in which the DSI net margin is calculated. This proposed change is not a section 7(b)(2) issue and is addressed in ROD chapter 15. In any event, the effect of the DSI margin assumption on the 7(b)(2) rate test trigger is minor, at most 0.2 mills/kWh, based on the IOUs' own testimony. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-06, at 14-15, citing Hoff *et al.*, WP-02-E-AC/GE/IP/MP/PL/PS-03, at 13, 19.

The IOUs also alleged elsewhere that BPA improperly continued a list of past mistakes in conducting the section 7(b)(2) rate test. Hoff *et al.*, WP-02-E-AC/GE/IP/MP/PL/PS-03, at 6-7. The first of these issues concerns BPA's ASC Methodology, which was developed in a separate administrative proceeding in 1984 and is not established in BPA's rate cases. This procedural issue is addressed in detail in the current proceeding. *See* ROD section 11.2. Because it is not a substantive rate case issue, it is not a continuing rate case "mistake." Another issue mentioned by the IOUs is BPA's 1996 alleged failure to equalize cash reserve accumulations in the Program Case and 7(b)(2) Case. The IOUs did not raise this issue in BPA's current rate case. Because they have not raised the issue in the current proceeding, and it is not a contested issue, it is inappropriate to refer to it as a continuing mistake. Another issue mentioned by the IOUs is BPA's 1996 alleged failure to limit the cash reserve accumulation. This is a revenue requirement issue and again, the IOUs did not raise this issue in BPA's current rate case. Because they have not raised the issue, and it is not a contested issue, it is inappropriate to refer to it as a continuing mistake. Another issue referenced by the IOUs is BPA's alleged failure to include the proper amount of section 7(g) costs as uncontrollable events in the 7(b)(2) rate test. This issue is being addressed in BPA's current rate case. The issues regarding uncontrollable events in the current case, however, are *different* issues from those addressed in BPA' 1996 rate case. As noted above, the current case involves PNRR and the costs of terminated generating facilities, arguments that were not raised by any party in BPA's 1996 rate case. Draft ROD, WP-02-A-01, section 13.3. Therefore, these issues cannot be continuing mistakes, as they are new issues. Another issue identified by the IOUs is the issue of calculating Mid-C resource availability and costs. This issue did not affect the development of BPA's rates in 1996 in any manner whatsoever, because the circumstances for implementing this issue did not arise. In addition, this issue is moot in the current rate case. Draft ROD, WP-02-A-01, section 13.5. It is inappropriate to refer to this issue as a continuing mistake when it did not affect BPA's 1996 rates and the issue is moot in the current rate case. Another issue referenced by the IOUs is the inclusion of a 7(b)(2) industrial adjustment in a 7(c)(2) delta calculation. This is a COSA issue and not a section 7(b)(2) rate test issue. More importantly, however, the IOUs did not raise this issue in BPA's current rate case. Because they have not raised the issue, and it is not a contested issue, it is inappropriate to refer to it as a continuing mistake. In summary, the IOUs' argument that BPA has continued mistakes from its 1996 rate case has little merit. The foregoing changes proposed by the IOUs (excluding the DSI margin), are addressed separately in greater detail in this chapter of the ROD.

As noted above, the IOUs and PGE argue that BPA misapplied the 7(b)(2) rate test in the 1996 rate case to arrive at a predetermined outcome, which was to keep DSI customers from leaving BPA. PGE Brief, WP-02-B-GE-01, at 5; IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 16. BPA disagrees with PGE's and the IOUs' argument, just as BPA disagreed with this argument in BPA's 1996 rate case. Boling and Doubleday, WP-02-E-BPA-53, at 12-13. In its WP-02 rebuttal testimony, BPA attached its 1996 rebuttal testimony responding to the testimony the IOUs attached to their WP-02 direct testimony. *Id.*, Attachment 1, Testimony of Marshall and Burns, WP-96-E-BPA-44. All such issues regarding BPA's 1996 rate case were addressed in BPA's 1996 ROD, WP-96-A-02. Boling and Doubleday, WP-02-E-BPA-53, at 13, Attachment 2. FERC granted final approval of BPA's rates, and the only petition for review filed with the United States Court of Appeals for the Ninth Circuit was voluntarily dismissed. Boling and Doubleday, WP-02-E-BPA-53, at 13. BPA's 1996 rates are final. *Id.*

Furthermore, triggering the 7(b)(2) rate test is not an effective tool to lower the cost of power sold to the DSIs. Kaptur *et al.*, WP-02-E-BPA-56, at 3. When the 7(b)(2) rate test triggers positively, it allocates PF Preference protection costs to the DSI rate class. *Id.* Those costs remain even after the section 7(c)(2) adjustment links the IP rate to the now lower PF Preference rate. In BPA's 1996 final rate proposal, the 7(b)(2) rate test triggered by 3.2 mills, providing $621.4 million in rate protection to the PF Preference rate class over five years. *Id.*; *see* 1996 Wholesale Power Rate Development Study Documentation, WP-96-FS-BPA-05A, page 195, Table RDS 30, line 3. Before the rate test triggered, the costs allocated to the DSI rate class were $1,556.6 million for five years. Kaptur *et al.*, WP-02-E-BPA-56, at 4. After the rate test triggered by 3.2 mills and the IP-PF link was reestablished, the costs allocated to the DSI rate class were $1,539.3 for five years, a reduction of about a 1 percent, or just $3.5 million per year. *Id.; see* 1996 Wholesale Power Rate Development Study Documentation, WP-96-FS-BPA-05A, page 197, Table RDS 33. The alleged massive reallocation of benefits from residential customers of IOUs to the DSIs did not happen in BPA's 1996 rate case. *Id.*

The Joint DSIs also established that the IOUs' claim that the 7(b)(2) rate test was manipulated to pay for a lower rate for the DSIs is baseless. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-06, at 14-15. The Joint DSIs note that while decisions on DSI issues can affect the 7(b)(2) rate test, the accusation that the 7(b)(2) rate test provided benefits for the DSIs is completely unsupportable. *Id.* The Joint DSIs note that issues regarding the 7(c)(2) floor rate test and the industrial margin have a small impact on the 7(b)(2) rate test, and to implicate these decisions as the cause of a large change in the rate test trigger is unfounded. *Id.* In the rate case, the combined effect of changing the floor rate and margin to the IOUs' position, ignoring that they are completely in error on the value of reserves exclusion from the floor rate, is at most 0.2 mills/kWh, based on the IOUs' own testimony. *Id.* The Joint DSIs also note that in BPA's 1996 rate case, the IP-96 rate was allocated $240,994,000 of the costs of providing the 7(b)(2) protection to the preference customers. *Id.* Then, $258,250,000 was restored to the IP rate through linkage of the IP rate to the PF Preference rate. *Id.* The difference, $17,256,000 spread over five years, was the total benefit realized by the DSIs in the IP rate through the 7(b)(2) rate test. *Id.* This equals 0.07 mills/kWh benefit. *Id.* To accuse BPA of manipulating the rate test in order to provide less than one-tenth of a mill benefit to the DSIs is simply not credible. *Id.*

Decision

The 7(b)(2) rate test was properly conducted in BPA's 1996 rate case. BPA does not rely on BPA's 1996 rate case decisions as binding and has evaluated all 7(b)(2) issues in the current proceeding. If certain positions are similar to previous rate cases, going back to 1985, it is because BPA believes that such positions are correct. BPA uses proper inputs and assumptions in its conduct of the 7(b)(2) rate test. The 7(b)(2) rate test has been performed properly in the current rate case.

14.0 INVESTOR-OWNED UTILITY (IOU) BENEFITS AND SETTLEMENTS

14.1 Benefits to Regional IOUs

Issue 1

Whether BPA has provided appropriate attention and benefits to residential and rural customers of regional IOUs, and whether an "end results test" applies to BPA's ratemaking.

Parties' Positions

The IOUs argue that BPA should apply an "end results test" to its proposed rates to determine whether the effect of the rates would be fair to the residential consumers of regional IOUs. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 6-7. The IOUs argue that BPA's initial proposal does not meet BPA's policy goals. *Id.* at 7-9. The IOUs argue that BPA's initial proposal frustrates the intent of Congress. *Id.* at 9-13. The IOUs' arguments are reiterated in their brief on exceptions. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 5-13. On the other hand, NRU argues that the IOUs' recommendation of an end results test has no foundation in the Northwest Power Act. NRU Brief, WP-02-B-NI-02, at 30. NRU also argues that the IOUs ignore that Residential Exchange benefits are provided only if the exchanging utility's ASC is greater than BPA's PF Exchange rate, and benefits are also limited by the 7(b)(2) rate test and BPA's right to sell in-lieu power to exchanging utilities. *Id.*

BPA's Position

Neither the Northwest Power Act nor any other statute or case law establishes an "end results test" regarding BPA ratemaking. *See* 16 U.S.C. §839e. Even if such a test were applicable, BPA's rates would satisfy such a test. BPA's initial proposal satisfies BPA's policy goals. BPA's initial proposal does not frustrate the intent of Congress.

Evaluation of Positions

The IOUs argue that BPA should apply an "end results test" to its proposed rates, which would provide that "[i]f the total effect of the rate order cannot be said to be unreasonable, judicial inquiry is at an end," and "[t]he fact that the method employed to reach the result may contain infirmities is not then important and the question is whether the order "viewed in its entirety" meets the requirements under applicable law. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 6-7, quoting *FPC v. Hope Natural Gas Co*., 320 U.S. 591 (1944). First, it is clear that *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), is inapposite. That case involved a proceeding under the Natural Gas Act. *Id.* at 602. The Court specifically reached its conclusions under a "statutory standard" and considered whether the Commission's order "meets the requirements of the Act." *Id.* The Natural Gas Act does not apply to BPA ratemaking. 15 U.S.C. §717(b). Later decisions have applied the end results test to the Federal Power Act, because that Act also requires that rates be "just and reasonable." *See Jersey Central Power & Light Co. v. FERC*, 810 F.2d 1168, 1175 (D.C. Cir. 1987). Again, however, the Federal Power Act does not apply to the development of BPA's wholesale power rates. 16 U.S.C. §824(f); 16 U.S.C. §832a(a). *See Central Lincoln PUD v. Johnson,* 735 F.2d 1101, 1113 n.6 (9th Cir. 1984); *Village of Bergen v. FERC*, 33 F.3d 1385, 1390 (D.C. Cir. 1994). The Northwest Power Act does not apply a just and reasonable test to BPA's wholesale power rates. 16 U.S.C. §839e.

In addition, later cases have allowed greater judicial inquiry into the details of the ratemaking process. *See Permian Basin Area Rate Cases*, 390 U.S. 747, 791 (1968). Other courts have recognized that "[e]xperience has taught that a determination of whether the result is just and reasonable requires an examination of the method employed in reaching that result." *City of Charlottesville v. FERC*, 661 F.2d 945, 950 (D.C. Cir. 1981). *See Shell Oil Co. v. FPC*, 520 F.2d 1061, 1071 (5th Cir,. 1975); *Jersey Central Power & Light Co. v. FERC*, 810 F.2d 1168, 1178 (D.C. Cir. 1987); *City of Brookings Municipal Telephone Co. v. FCC*, 822 F.2d 1153, 1164 (D.C. Cir. 1987). Furthermore, even if one assumed, *arguendo,* that an end results test were applicable, BPA's proposed wholesale power rates, as discussed in greater detail below, pass that test.

The IOUs note that BPA established that: (1) neither the Northwest Power Act nor any other statute or case law establishes an end results test for BPA ratemaking; (2) that the Northwest Power Act does not apply a just and reasonable test to BPA's wholesale power rates; and (3) so long as each individual issue is considered and determined on its merits, there is no overall end results test required. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 8. In support of the third proposition cited by the IOUs, they refer to the Draft ROD, WP-02-A-01, at 14-8. BPA found no such discussion at that location. The IOUs argue that BPA admits in the Draft ROD that "[n]evertheless, we are required to reject BPA's constructions of a statute that are inconsistent with the statutes or frustrate the policy Congress sought to implement. *Southern Cal. Edison Co. v. FERC*, 770 F.2d 779, 782 (9th Cir. 1985)." *Id*. Obviously this was not BPA's statement but rather a statement of the United States Court of Appeals for the Ninth Circuit cited by BPA. BPA does not contest the court's statement as a matter of law, but finds it inapplicable to BPA's statutory interpretations in this proceeding. In addition, the IOUs have failed to present the other side of the coin recognized by the court. Immediately preceding the portion of the court's statement cited by the IOUs, the court states:

> We must affirm BPA's action unless it is arbitrary, capricious, an abuse of discretion, or in excess of statutory authority. 16 U.S.C. §839f(e)(2); 5 U.S.C. §707; *CEC*, 831 F.2d, at 1472. This standard of review is deferential to and presumes that agency action to be valid. *Citizens to Preserve Overton Park v. Volpe*, 401 U.S. 402, 415, 91 S.Ct. 814, 823, 28 L.Ed. 2d 136 (1971). Because BPA drafted the Northwest Power Act, its interpretation of the Northwest Power Act is to be given "great weight" and should be upheld if reasonable. *Aluminum Co. of America v. Central Lincoln Peoples' Util. Dist.*, 467 U.S. 380, 389-90, 104 S. Ct. 2472, 2479-80, 81 L.Ed. 301 (1981) (ALCOA I); *Aluminum Co. of America v. Bonneville Power Admin.*, 891 F.2d 748, 752 (9th Cir. 1989) (ALCOA II).

California Energy Comm'n v. Bonneville Power Admin., 909 F.2d 1298, 1306 (9th Cir. 1990).

The IOUs argue that BPA's actions should not frustrate the intent of Congress. IOU Ex. Brief, WP-02-B-AC/GE/IP/MP/PL/PS/EN-01, at 9. Also, the IOUs argue that BPA cannot argue that each individual decision was reasonable if it does not add up to a reasonable result. *Id*. As explained in great detail in BPA's discussion of the issues in this ROD, BPA's actions are consistent with Congressional intent, and BPA's decisions produce reasonable results. These results may not produce what a particular customer class would like, but the Northwest Power Act does not prescribe specific amounts of benefits for each customer class. For example, Residential Exchange benefits for the IOUs and other exchanging utilities may be limited by section 7(b)(2) of the Northwest Power Act, which Congress designed to establish a rate ceiling for BPA's preference customers. *See* 16 U.S.C. §839e(b)(2).

The IOUs also argue that BPA is incorrect in saying that "wholesale rate parity" means exactly what it says--parity of wholesale rates charged by BPA to its preference and exchange customers (subject to the section 7(b)(2) rate test). IOU Ex. Brief, WP-02-B-AC/GE/IP/MP/PL/PS/EN-01, at 9, n. 26. Instead, the IOUs argue that it means parity between an IOUs' average cost of power and BPA's wholesale rate for power to public agencies and cooperatives. The IOUs' argument is unclear. If the IOUs' reference is to the IOUs' ASCs, then their argument is incorrect. If wholesale rate parity occurred where a utility's ASC is equal to the PF Exchange rate, this would result in the payment of *no* REP benefits to the IOU on behalf of its residential consumers. Such a concept of wholesale rate parity would eliminate the REP. If the IOUs' argument is that wholesale rate parity occurs where a utility's ASC is equal to the PF Preference rate, this would also make no sense. Because in this rate case, for example, the PF Preference rate is lower than the PF Exchange rate, this approach also would result in the payment of *no* REP benefits to the IOU on behalf of its residential consumers. This concept of wholesale rate parity also would eliminate the REP. BPA's interpretation of wholesale rate parity is correct.

The IOUs cite *Jersey Central Power & Light Co. v. FERC*, 810 F.2d 1168, 1178 D.C. Cir. (1987) for the proposition that an order cannot be justified simply by showing that each of the choices underlying it was reasonable, but that those choices must add up to a reasonable result. IOU Ex. Brief, WP-02-B-AC/GE/IP/MP/PL/PS/EN-01, at 10. *Jersey Central*, which is based on review under the Federal Power Act, is inapposite. As noted in greater detail above, neither the Natural Gas Act nor the Federal Power Act apply to BPA's wholesale power ratemaking and do not impose an end results test on BPA.

The IOUs also argue that BPA's rates are subject to the Administrative Procedure Act standards of review. IOU Ex. Brief, WP-02-B-AC/GE/IP/MP/PL/PS/EN-01, at 10. As demonstrated by the comprehensive discussion of the issues in this case, BPA's decisions are in accordance with law and with applicable standards for judicial review. The merits of each issue are addressed in the section of this ROD discussing that issue and in other relevant sections. The IOUs also argue that BPA's rate proposal creates such an unjustifiable disparity that it would violate the Fifth Amendment of the U.S. Constitution by denying equal protection and due process to the residential and small farm consumers of the Northwest utilities. IOU Ex. Brief, WP-02-B-AC/GE/IP/MP/PL/PS/EN-01, at 10. However, the IOUs' constitutional arguments consist of a single sentence that generally asserts these alleged violations. *Id.* Other than this bare assertion, the IOUs make no demonstration of how rate disparity rises to the level of a constitutional violation. Similarly, the IOUs do not demonstrate how applicable standards that pertain to establishing equal protection and due process violations have been met. Nevertheless, it is clear their arguments are without merit. First, the relevant due process issue under the Fifth Amendment of the U.S. Constitution would be *procedural* due process, not substantive due process. Given the lengthy procedural schedule in this case, the extensive opportunities for discovery, the filing of direct testimony, the filing of rebuttal testimony, the extensive opportunity for cross-examination, the opportunity for initial briefs and briefs on exceptions, the opportunity for oral argument, and the other procedural features of this proceeding, BPA's rate proposal does not deny the residential customers of exchanging utilities procedural due process. Second, with respect to the IOUs' equal protection claim, exchanging utilities are a class of customers defined in the Northwest Power Act. Preference customers are a class of customers defined in the Northwest Power Act. DSI customers are a class of potential customers defined in the Northwest Power Act. The Northwest Power Act prescribes the manner in which such classes have access to the benefits of the Federal system. As noted previously, the benefits provided to the IOUs and preference utilities under the REP are subject to change based upon the utilities' ASCs and the level of BPA's PF Exchange rate. The Act establishes the section 7(b)(2) rate test for preference customers to protect such customers from, among other things, the costs of the REP. If the rate test triggers, BPA must allocate costs to other non-preference rates, including the PF Exchange rate. When the PF Exchange rate increases, REP benefits decrease because the gap between the utility's ASC and BPA's PF Exchange rate grows smaller. Changes in REP benefits due to these statutory requirements are not denials of the IOUs' rights.

The IOUs argue that BPA's policy witness said the first of BPA's four goals was to "spread the benefits of the FCRPS as broadly as possible with special attention given to residential and rural customers of the region." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 7. The IOUs argue that BPA's witness agreed that BPA's goal of providing "special attention to the residential and rural customers" was required by statute. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 7. Tr. 119-20. This statement requires clarification. IOU counsel asked whether "BPA is required by statute to emphasize residential and rural customers." Tr. 119. This is a legal issue. BPA's witness Mr. Burns replied by noting the existence of the REP. *Id.* BPA does not dispute that the REP provides benefits to regional residential consumers. BPA's witness, Mr. Burns, however, is not a lawyer and is not able to address issues regarding the law. His testimony on this matter must therefore, be given little weight. Whether BPA is required by law to emphasize residential and rural customers must be found in the Northwest Power Act or other applicable legislation. BPA's review of applicable law has not located a provision that states what the IOUs allege. The Bonneville Project Act states that BPA's rate schedules "shall be fixed and established with a view to encouraging the widest possible diversified use of electric energy." 16 U.S.C. §832e. This provision, however, does not state that "special attention [be] given to residential and rural customers of the region." The Bonneville Project Act also provides that:

> In order to insure that the facilities for the generation of electric energy at the Bonneville Project shall be operated for the benefit of the general public, and particularly of domestic and rural consumers, the administrator shall at all times give preference and priority to public bodies and cooperatives.

16 U.S.C. §832c(a). Again, this provision does not require special attention for the residential and rural consumers of IOUs, but rather of BPA's preference customers.

The IOUs argue that under BPA's initial proposal, the dollar benefits to residential and rural customers of the IOUs would be approximately $140 million a year. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 8; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 5-6. The IOUs argue that this means that 60 percent of the residential and small farm customers of the region will receive less than 23 percent of the benefits of the Federal hydropower system. *Id.* The IOUs argue that if BPA benefits reach $1 to $2 billion per year, it would mean that the IOUs' residential consumers would receive only 7 to 14 percent of total benefits to the region. *Id.* This argument must be viewed in the context of the statutory framework that provides benefits to all of BPA's customers. The primary law establishing these obligations is the Northwest Power Act. Implementation of the directives of the Northwest Power Act results in benefits of the Federal power system that flow to BPA's customers and, where applicable, to retail consumers of those customers. One of the most fundamental requirements of the Northwest Power Act is that public bodies and cooperatives have preference and priority to the purchase of Federal power to meet their net requirements. 16 U.S.C. §832(a); 16 U.S.C. §839c(a). This power is used to serve all requirements loads of such preference customers, including residential, commercial, and industrial loads. Preference customers also pay the PF Preference rate for their power purchases. BPA's rate directives establish the manner in which BPA must allocate costs in establishing the PF rate, which applies to BPA's preference customers and utilities participating in the REP. 16 U.S.C. §839e(b)(1). The PF rate for utilities participating in the REP is subject to adjustment pursuant to 7(b)(2) of the Northwest Power Act, 16 U.S.C. §839e(b)(2), which is discussed in greater detail in ROD chapter 13. Due to the cost allocation directives of section 7 of the Northwest Power Act, and the fact that FBS power can be priced well below other sources of power, the PF Preference rate is currently BPA's lowest rate for firm power requirements service. Therefore, under the law, BPA's preference customers receive substantial benefits from the Federal power system by being able to purchase their net requirements at the PF Preference rate.

IOUs may benefit in a number of ways from the Northwest Power Act. First, like BPA's preference customers, IOUs may place their net requirements load on BPA. 16 U.S.C. §839c(b)(1). The rate directives for IOUs' requirements power, unlike those for BPA's preference customers, are contained in section 7(f) of the Northwest Power Act, which generally results in NR rates that are higher than the PF Preference rate. Due to the level of the NR rate, BPA has forecasted few requirements sales under the NR rate to IOUs for the rate period. (A discussion of requirements sales to IOUs as part of a settlement of the REP is discussed later in this section.) A second way in which IOUs benefit from the Northwest Power Act is the REP. 16 U.S.C. §839c(c). Under the REP, BPA "purchases" power from each participating utility at that utility's ASC. Boling and Doubleday, WP-02-E-BPA-30, at 2. The Administrator then offers, in exchange, to "sell" an equivalent amount of electric power to the utility at BPA's PF Exchange power rate. *Id.* The amount of power purchased and sold is the qualifying residential and small farm load of each utility participating in the REP. *Id.* The Northwest Power Act requires that the net benefits of the REP be passed through directly to the residential and small farm customers of the participating utilities. *Id.* Under the normal implementation of the REP, no actual power is transferred either to or from BPA. *Id.* The "exchange" has been referred to as a "paper" transaction, where BPA provides the participating utility cash payments that represent the difference between the power "purchased" by BPA and the less expensive power "sold" to the participating utility. *Id.*

As noted above, under the REP, IOUs pay the PF Exchange rate for power purchased from BPA. This rate, however, may not be the same level as the PF Preference rate. The Northwest Power Act established what is called the 7(b)(2) rate test, which is discussed in greater detail in ROD chapter 13. 16 U.S.C. §839e(b)(2). This test is designed to protect preference customers from certain costs incurred under the Northwest Power Act, including Residential Exchange costs. If the 7(b)(2) rate test does not trigger, the PF Preference rate and the PF Exchange rate are equal. If the 7(b)(2) rate test triggers, however, the PF Exchange rate is subject to a surcharge and is higher than the PF Preference rate. The lower the PF Exchange rate, the higher the exchange benefits. The higher the PF Exchange rate, the lower the exchange benefits. This is the manner in which rates must be established by BPA under the Northwest Power Act. Where, as in the current rate case, the 7(b)(2) rate test triggers, it is not at all surprising that consumers of preference customers would receive greater "benefits" than the IOUs' residential consumers. This is the way that the Northwest Power Act works. In years when the 7(b)(2) rate test did not trigger, as has occurred periodically over the last 15 years, the IOUs receive greater benefits. In years when the 7(b)(2) rate test triggers, the IOUs receive lesser benefits. In summary, while different customer classes may receive greater or lesser benefits of the Federal system in any particular rate period, this is a result of the implementation of the directives of the Northwest Power Act. While it is unfortunate that some customer classes may receive greater benefits than other customer classes, BPA cannot unilaterally change the law. *See* NRU Brief, WP-02-B-NI-02, at 30.

The IOUs argue that BPA witness Burns stated that he did not know if anyone at BPA compared the end result of the rate test to Congressional intent. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 8. The IOUs argue that as BPA's senior policy witness in this case, it was up to Mr. Burns to examine the end result. *Id.* at 8-9. The IOUs fail to recognize, however, that the determination of Congressional intent is a legal matter. As noted previously, because Mr. Burns is not a lawyer, he would not be able to provide a legal judgment regarding such intent. In addition, as previously noted, there is no end results test applicable to BPA's ratemaking. Furthermore, BPA has been developing rates under the Northwest Power Act for nearly 20 years. In each rate case BPA has conducted, BPA has implemented the same statutory rate directives as in the previous rate case, subject to the changes in the rate directives beginning in 1985. In addition, BPA reviewed the Northwest Power Act and its legislative history in developing BPA's Legal Interpretation of 7(b)(2) in 1984, b-2-84-FR-03. BPA also reviewed the Northwest Power Act and its legislative history in developing BPA's 7(b)(2) Implementation Methodology in 1984, b-2-84-F-02. BPA also has conducted the 7(b)(2) rate test in every rate case since 1985, except in the few cases where the rate case was settled and the test was not performed. In summary, BPA is extremely familiar with the 7(b)(2) rate test and the Congressional intent behind the test. This makes a comparison of the results of the rate test with Congressional intent an inherent part of the rate test. BPA's extensive review of the legislative intent of the 7(b)(2) rate test is found elsewhere in this ROD. After reviewing BPA's implementation of the 7(b)(2) rate test in the current rate case, the end result of the rate case and BPA's proposed rates are perfectly consistent with the Northwest Power Act, the legislative history of the Northwest Power Act, and other applicable rules.

The IOUs' basic premise, however, is troubling. BPA develops its rates in accordance with the Northwest Power Act, other applicable legislation and other rules (*e.g.*, the 7(b)(2)

Implementation Methodology). As BPA noted, "[e]ach issue regarding the 7(b)(2) rate test is considered and determined on its merits. Similarly, other rate case issues must be determined on their merits." Boling and Doubleday, WP-02-E-BPA-53, at 17. The IOUs' argument appears to be that instead of considering and determining each issue on its merits, BPA should make a subjective judgment regarding whether any party is receiving a level of benefits from BPA that is somehow appropriate. The IOUs apparently argue that if a party is not receiving benefits that are somehow appropriate, BPA should not consider and determine each issue on its merits, but instead should make decisions it does not believe are correct in order to favor the parties that are allegedly not receiving enough benefits. This approach is simply wrong and contrary to the Northwest Power Act. 16 U.S.C. §839e.

The IOUs argue that, "in a striking admission," BPA's policy witness acknowledged that BPA's initial proposal would produce lower benefits to residential and rural consumers of IOUs than to the commercial and industrial customers of government-owned utilities and co-ops. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 9. Tr. 132. However, the IOUs' transcript citation presents substantial ambiguity. The transcript states:

> Q. So I take it then, based upon what you have just said, that BPA's initial proposal will produce lower rates and benefits to residential and rural customers of IOUs than to the commercial and industrial customers of government-owned utilities and co-ops?
>
> A. (Mr. Burns) Basically, on a per person basis or average, yes. Yes.

Tr. 132.

The first ambiguity is in the question asked by counsel for the IOUs. The question asks whether BPA's initial proposal will produce "lower rates and benefits" to residential and rural customers of IOUs. *Id.* This is an oxymoron. If the initial proposal produces lower rates for residential and rural customers, *i.e.*, a lower PF Exchange Program rate, there would be greater benefits for residential and rural customers because there would be a larger gap between the exchanging utility's ASC and the PF Exchange Program rate. In addition, BPA does not establish rates for the residential consumers of IOUs, but rather, rates for the IOUs that implement the REP. BPA also does not establish rates for commercial and industrial customers of government-owned utilities and co-ops, but rather, rates for the publicly owned utilities that serve the companies. Thus, the question asked is unclear. In addition, the witness's answer is ambiguous because, while asked about rates and benefits to residential and rural consumers, *i.e.*, people, compared to commercial and industrial customers, *i.e.*, companies, the witness answered only with regard to a "per person" basis or average. *Id.* Even assuming, *arguendo*, that the IOUs' characterization of this exchange were correct, this is hardly a "striking" admission.

Under the law, BPA is required to offer power first to public bodies and cooperatives, known as preference customers. 16 U.S.C. §832(a); 16 U.S.C. §839c(a). This power is provided to serve all requirements loads of such preference customers, including residential, commercial, and industrial loads. Preference customers pay the PF Preference rate for their power purchases. Commercial and industrial customers of publicly owned utilities benefit indirectly from the sales to their publicly owned utilities at the PF Preference rate. This rate is currently BPA's lowest firm power requirements rate. IOUs, however, participate in the REP. Under that program, IOUs pay the PF Exchange rate for power purchased from BPA, which is compared with the utility's ASC to determine exchange benefits. Because there are IOUs with ASCs lower than BPA's PF Exchange Program rate (sometimes due to a utility's own cheap hydro resources), consumers of such IOUs receive no exchange benefits. Thus, a commercial or industrial customer of a publicly owned utility, because it benefits indirectly from the PF Preference power purchased by its publicly owned utility, would benefit more than consumers of IOUs with ASCs below the PF Exchange rate. Even for IOUs with ASCs above the PF Exchange rate, the PF Exchange rate may be higher than the PF Preference rate due to the 7(b)(2) rate test. The higher the PF Exchange rate, the lower the exchange benefits. This is the manner in which rates must be established and the program implemented by BPA under the Northwest Power Act. Where, as in the current rate case, the 7(b)(2) rate test triggers, commercial and industrial customers of preference customers would receive benefits from their publicly owned utility's PF Preference power purchases. The IOUs' residential consumers would receive benefits based on the relationship of their utility's ASC to the PF Exchange Program rate. There is no analysis in the record to compare the benefits for any particular commercial or industrial customer of a publicly owned utility with a particular residential consumer of an exchanging utility. However, there would likely be differences. This is the way that the Northwest Power Act works. In years when the 7(b)(2) rate test did not trigger, as has occurred in past years, the IOUs received greater benefits. In years where the 7(b)(2) rate test does trigger, the IOUs receive lesser benefits.

The IOUs discuss Congressional intent in establishing the REP. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 9-13; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 11-12. BPA discusses the background of the REP in ROD chapters 11 and 13. Much of BPA's description is consistent with the IOUs' description. There are, however, a number of clarifications of the IOUs' arguments that should be noted. First, omitted from this discussion in the IOUs' brief is a discussion of Congressional intent in establishing the 7(b)(2) rate test. As noted in BPA's discussion of the background of the 7(b)(2) rate test, there are direct connections between these two features of the Northwest Power Act. BPA discusses this subject in ROD chapter 13. In addition, the IOUs cite no provision that establishes a particular level of Residential Exchange benefits. Instead, there are general statements in legislative history that the Northwest Power Act would provide "a share in the economic benefits of the lower-cost Federal system for the residential consumers of the non-preference customers," and would "extend the benefits of low-cost federal power to consumers served by investor-owned utilities." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 10-12. These statements, however, establish no particular amount of benefits or test for benefits. Instead of relying on the Northwest Power Act, where no particular level of benefits is guaranteed, the IOUs quote a policy specialist from the Washington Utilities and Transportation Commission, an entity, like all regional state public utility commissions, that shares the IOUs' interest in receiving as much money as possible from the Federal Government under the REP. *Id.* at 12. While the policy person stated her opinion that the residential consumers of IOUs are "provided equal access to the benefits of the Federal hydropower system through an exchange program," this statement is clearly inconsistent with the Northwest Power Act itself, which nowhere specifies that the IOU benefits provided under the REP would be equal to the benefits provided to BPA's preference customers. Furthermore, after the detailed statutory and legislative history analysis in the introduction to chapter 13, BPA concluded that the Northwest Power Act expressly contemplates that section 7(b)(2) could completely eliminate exchange benefits for utilities whose ASC rate was less than BPA's PF Exchange rate.

Similar arguments based on this witness's testimony were refuted during the hearing. An IOU, citing this witness's testimony regarding Appendix B of the Report of the Senate Committee on Energy and Natural Resources, S. Rep. 272, 96th Cong., 1st Sess. (1979), claimed that the Northwest Power Act intended that IOUs' residential consumers should receive greater monetary benefits under the REP than proposed by BPA. Gaines, WP-02-E-PS-01, at 7-8. The Joint DSIs noted that this argument was unfounded. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-06, at 15-16. The witness cited by the IOUs selected only elements of forecasts performed 20 years ago of events that were then 15 years in the future. *Id.* The witness compared those selected elements to events that actually occurred. *Id.* The witness's testimony ignored the faulty underlying assumptions that have rendered moot the forecasts done in 1979 during Congressional consideration of the Northwest Power Act. *Id.* To argue that there is some significance to the fact that the 1979 forecasts predicted that the Residential Exchange benefits would be higher than actually occurred and that the DSI rates were forecasted to be higher than actually determined, without exploring all of the assumptions that went into that forecast, is disingenuous. *Id.* Among the expectations in 1979 are: preference customer loads on BPA that were forecasted to be more than twice the 1997 loads, IOU loads were forecasted to be 25 percent higher, 40 percent of IOU loads were assumed to be served with BPA power, DSI loads on BPA were expected to be 250 percent of the actual 1997 loads, the FBS was forecasted to cost 60 percent of its actual cost in 1997 and to be 20 percent larger in size, BPA was forecasted to acquire 9,800 MW more new resources than the 230 MW BPA actually acquired, the actual cost of the new resources was 60 percent of the 1979 forecast, and Residential Exchange loads were about one-half of forecasted loads. *Id.* Actually, about the only significant forecast from 1979 that proved correct was the cost of exchange resources: the forecasted cost was 33.7 mills/kWh, while the actual cost was 33.3 mills. *Id.* These changes radically affected BPA's rates. *Id.* The difference between the forecast of DSI rates in 1979 and the actual rates in 1996 is directly attributed to the vast difference in the assumptions used to make these forecasts and actual developments. *Id.* None of these reasons relates to the 7(b)(2) rate test, but rather the amount of load growth in the Northwest and the resource acquisitions made by BPA to serve the load growth. *Id.* Furthermore, Appendix B, which was relied on by the witness, was incorporated in the Senate Report with reservations. *Central Lincoln PUD v. Johnson*, 735 F.2d 1101, 1123 (9th Cir. 1984).

The IOUs also cite *Public Utility Commissioner of Oregon v. Bonneville Power Admin.*, 767 F.2d 622, 624 (9th Cir. 1985) for the proposition that "[o]ne of the goals of the Northwest Power Act is to ensure that residential customers served by Northwest IOU's have wholesale rate parity with residential customers served by publicly owned utilities and public cooperatives, BPA's preference customers." This case did not involve a substantive ruling on the REP. Instead, the court merely held that it lacked jurisdiction to review the case because the action was required to be final before it was reviewable. *Id.* at 628. More important, however, is that the term "wholesale rate parity" means exactly what it says: parity of wholesale rates charged by BPA to its preference and exchange customers. This is achieved in the Northwest Power Act by providing that the wholesale power rates for BPA's sales to its preference customers and the wholesale power rates for BPA's sales to IOUs for the REP will be at the same rate, that is, the PF rate. This basic point, however, is not always true, because the Northwest Power Act also includes section 7(b)(2), which can result in an allocation of costs such that the PF rate paid by exchanging utilities is higher than the PF rate paid by preference customers.

The IOUs argue that providing 60 percent of the region's citizens with less than 23 percent of the Federal power benefits has led to increased pressure to form government-owned utilities to take over areas served by IOUs. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 12. Federal power benefits are provided to IOUs in large part through the REP. Boling and Doubleday, WP-02-E-BPA-53, at 21. REP benefits are determined by comparing an exchanging utility's ASC with BPA's PF Exchange Program rate. *Id.* The PF Exchange Program rate level is determined in large part by incorporating the results of the 7(b)(2) rate test. *Id.; see* 7(b)(2) Rate Test Study, WP-02-E-BPA-06; Kaptur *et al.*, WP-02-E-BPA-34; and Kaptur *et al.*, WP-02-E-BPA-56. Each issue regarding the 7(b)(2) rate test is considered and determined on its merits. Boling and Doubleday, WP-02-E-BPA-53, at 21. It is not BPA's intent to create pressure to form government-owned utilities or to reignite battles between public and private power. *Id.* The IOUs argue that Congress had the right remedy in the REP: rate parity. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 13. Wholesale rate parity, however, as noted above, is something that is already implemented by BPA in each rate case. If there is no 7(b)(2) trigger, there is parity in wholesale rates. If there is a 7(b)(2) trigger, there is not exact rate parity. This is required by section 7(b)(3) of the Northwest Power Act. 16 U.S.C. §839e(b)(3).

The IOUs argue that BPA's initial rate proposal fails to meet the goal of spreading the benefits of the FCRPS as broadly as possible, with special attention given to the region's residential and rural customers. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 13; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 13. In addition to the points noted above, however, BPA is meeting its aforementioned goal. BPA's rate proposal, as explained throughout this ROD, provides benefits of the Federal power system to all of BPA's customer groups and other interest groups. As reflected in their briefs, the customer groups disagree with each other on the benefits being provided to each other customer group. The IOUs believe that they are not receiving enough benefits and ardently oppose elements of BPA's proposed rates for the DSIs and preference customers. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01. Alcoa and Vanalco, two DSIs, believe they are not receiving enough power or proper rates and that BPA should not sell power to the IOUs at the RL rate. Alcoa/Vanalco Brief, WP-02-E-B-AL/VN-01. The preference utilities argue that they are being treated unfairly in BPA's proposed rates, and some preference groups oppose power sales to the IOUs at the RL rate. WPAG Brief, WP-02-B-WA-01. While benefits are being spread to each customer group, it is difficult to ensure that any or all of such groups will be happy with the benefits they receive.

BPA established its Subscription Strategy with a number of goals: to spread the benefits of the FCRPS as broadly as possible, with special attention given to the residential and rural customers of the region; to avoid rate increases through a creative and business-like response to markets and additional aggressive cost reductions; to allow BPA to fulfill its fish and wildlife obligations while assuring a high probability of U.S. Treasury payment; and to provide market incentives for the development of conservation and renewables as part of a broader BPA leadership role in the regional effort to capture the value of these and other emerging technologies. *See* Subscription Strategy, at 3-4. BPA believes that its proposed rates achieve these goals. BPA's goal of spreading the benefits of the FCRPS as broadly as possible, with special attention given to the residential and rural customers of the region, is implemented in the Subscription Strategy by BPA's proposed settlements of the REP with regional IOUs. *Id.* at 8-10, 16-17. BPA's rate case has proposed rates that would implement these proposed settlements. Furthermore, BPA's forecasted Residential Exchange benefits to the IOUs comprise approximately $37 million per year during the rate period. Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 91. In providing special attention to residential and rural customers of the IOUs and giving them an additional option in access to Federal benefits, BPA forecasted exchange settlement benefits to the IOUs that total approximately $140 million per year during the rate period. Tr. 122. To suggest that BPA is not giving special attention to the region's residential and rural customers of IOUs is simply incorrect.

Decision

Neither the Northwest Power Act nor any other statute or case law establishes an "end results test" regarding BPA ratemaking. See 16 U.S.C. §839e. Even if such a test were applicable, BPA's rates would satisfy such a test. BPA is providing special attention to residential and rural customers and providing benefits in a manner consistent with law. BPA is properly providing benefits of the Federal system to IOUs through implementation of the REP and through proposed Subscription settlements of that Program. BPA's decisions comply with statutory standards for ratemaking and statutory standards for judicial review.

14.2 Residential Load Firm Power (RL) Rate

Issue

Whether BPA is required to establish an RL rate that is of general applicability and that is approximately equal to the PF Preference rate.

Parties' Positions

The IOUs argue that the Subscription ROD states that BPA would develop rates for power products that are approximately equal for all customer groups. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 61-63. They also argue that this is consistent with BPA's obligation under section 7(b) of the Northwest Power Act to establish rates of general applicability. *Id.* The IOUs argue that BPA has not complied with these conditions because there is a significant difference in the products offered to different customer groups at those rates. *Id.* The IOUs reiterate these issues in their brief on exceptions. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 44-46.

BPA's Position

BPA's Subscription Strategy did not make any final rate decisions regarding rates being approximately equal for all customer groups. BPA's rates satisfy the Northwest Power Act's requirements regarding the establishment of rates of general applicability. The power product available for the IOU REP settlements is described in BPA's Subscription Strategy, and the rate for that product is the same rate that would be paid for that product by a preference customer.

Evaluation of Positions

The IOUs argue that the Subscription ROD states that BPA would develop rates for power products that are approximately equal for all customer groups. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 61. BPA's Subscription ROD, however, does not state that BPA *would* develop approximately equal rates, but rather that BPA *proposed* to develop such rates. Subscription ROD, at 8. Discussions of rates in the Subscription Strategy and ROD consistently note that BPA is not making any final rate decisions in the Subscription Strategy. BPA's Subscription Strategy did not state that the IOU settlement sales would be charged a "PF-equivalent" rate, but rather, BPA's expectation was that "[t]hese sales [to IOUs] will be at a rate approximately equal to the PF Preference rate, *subject to establishment in BPA's rate case and consistent with BPA's rate directives*." *Id.;* Subscription Strategy, at 16 (emphasis added). The Subscription ROD also notes that:

> Subscription power sales (*i.e.,* power contracts signed during the Subscription window) to public agency customers will be at the PF rate. Subscription sales to IOUs and DSIs would be at *applicable* rates, which are *expected* to be approximately equivalent to the PF rate, *subject to a section 7(i) hearing and BPA meeting its statutory rate directives*.

Subscription ROD, at 9 (emphasis added).

BPA's statements in the Subscription Strategy and ROD were not final rate decisions. Final rate decisions can be made only in a section 7(i) hearing process. 16 U.S.C. §839e(i). BPA's discussions on rate issues in the Subscription process were limited to discussions of what might be included in BPA's initial proposal and then might be subject to change in the formal hearing. In any event, in BPA's initial proposal, as discussed in greater detail below, rates for relevant firm power sales are approximately equal for all customer groups.

The IOUs argue that the concept that BPA would develop rates for power products that are approximately equal for all customer groups is consistent with BPA's obligation under section 7(b) of the Northwest Power Act to establish rates of general applicability for power sold to meet the requirements loads of government-owned and cooperative customers and part of the residential loads of IOUs. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 61-62. BPA disagrees with the IOUs' argument that BPA's obligation to establish rates of general applicability necessarily obligates BPA to make these rates approximately equal for all customer groups. section7(b)(1) of the Northwest Power Act provides that "[t]he Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest, and loads of electric utilities under section 839c(c) of this title . . . " 16 U.S.C. §839e(b)(1). This provision relates only to the establishment of rates that apply to BPA's net requirements sales to preference customers, at the PF Preference rate, and BPA's sales to utilities under the REP, at the PF Exchange rate. Under the REP, IOUs pay the PF Exchange rate for power purchased from BPA. This rate, however, may not be the same level as the PF Preference rate. The Northwest Power Act established what is called the 7(b)(2) rate test, which is discussed in greater detail in ROD chapter 13. 16 U.S.C. §839e(b)(2). This test is designed to protect preference customers from certain costs incurred under the Northwest Power Act, including Residential Exchange costs. If the 7(b)(2) rate test does not trigger, the PF Preference rate and the PF Exchange rate are equal. If the 7(b)(2) rate test triggers, however, the PF Exchange rate is subject to a surcharge and is higher than the PF Preference rate. Even though the PF Preference and PF Exchange rates differ, they are rates of general applicability for the relevant sales to BPA's customer classes. Therefore, the fact that BPA develops rates of general application for sales to preference customers and sales to exchanging utilities, respectively, does not mean that those rates will be approximately equal.

The IOUs argue that BPA has not complied with the above-noted alleged conditions because there is a significant difference in the products offered to different customer groups at those rates. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 62. First, to the extent the IOUs are arguing that BPA's rates for power products should be approximately equal for all customer groups, it should be noted that the base rates for BPA's customer groups for primary Subscription sales are approximately equal. That is, the level of the PF Preference rate is approximately equal to the rate for the Subscription product proposed for the IOUs in BPA's Subscription Strategy, and both of these are approximately equal to the rate BPA is charging for the first 990 aMW of Subscription sales to the DSIs. In BPA's initial proposal, the monthly diurnal energy rates for the PF Preference and RL rates are equal. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 101. The monthly diurnal energy IP rates calculated for the initial IP load of 990 aMW are only 1.82 mills/kWh higher than the corresponding PF Preference and RL rates. *Id.* The IP energy rates are higher due to the implementation of the "floor rate test" as prescribed by section 7(c)(2) of the Northwest Power Act. *Id.*; 16 U.S.C. §829e(c)(2). The monthly demand charges are the same for all major firm power rates: PF Preference, RL, and IP. *Id.*

To the extent that the IOUs are arguing that the requirement of general applicability in section 7(b)(1) of the Northwest Power Act somehow requires that the PF Preference rate and the RL rate must be approximately equal, such an argument is misplaced. First, as noted above, section 7(b)(1) applies only to sales to preference customers under the PF Preference rate and sales to exchanging utilities at the PF Exchange rate. It does not apply to the RL rate. The RL rate is a special firm net requirements rate that applies only to sales from BPA offered as part of a settlement of the REP. The RL rate is established under section 7(f) of the Northwest Power Act, not section 7(b)(1). *See* 16 U.S.C. §839e(f); 16 U.S.C. §839e(f). Rates of general application established under section 7(b)(1) of the Northwest Power Act do not include rates such as the RL rate, which is established under section 7(f) of the Northwest Power Act.

The IOUs also argue that BPA's initial proposal offers a 24-hour flat-block power product at the RL rate to the IOUs and offers shaped power (including a flat-block power product with some shape) to preference customers at the PF Preference rate. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 62. First, it must be noted that BPA's proposed Subscription settlement sales to IOUs were consistently described in BPA's Subscription Strategy. BPA's Subscription Strategy notes that:

> In Subscription, BPA proposes a settlement [of the REP] in which residential and small farm loads of the IOUs would be assured access to the equivalent of 1,800 aMW of Federal power for the 2002-2006 period. Of this amount, at least 1,000 aMW will be met with actual BPA power deliveries. The remainder may be provided through either a financial arrangement or additional power deliveries, depending on which approach is more cost-effective for BPA.
>
> BPA and each IOU will negotiate the physical and financial components of the Subscription amount, by year, in the negotiated subscription settlement contracts. Any cash payments will reflect the difference between the market price of power forecasted in BPA's rate case and the rate used to make such Subscription sales. The actual power deliveries for these loads will be in equal hourly amounts over the period . . .

Subscription Strategy at 9. The Subscription Strategy also states that:

> BPA is also making an offer to the IOUs for settlement of the REP comprised of a specified amount of power and monetary payments. The terms and conditions of the settlement proposal are prescribed in order to establish what BPA feels is an appropriate value for the settlement of the REP. Thus, most of the service alternatives available to preference customers continue to be available to the IOUs under traditional requirements contracts and rate schedules. The Subscription settlement power sales, however, are available only under the prescribed conditions.

Id. at 45.

The Subscription Strategy then notes that "the actual power deliveries for the residential and small farm loads of IOUs will be in equal hourly amounts over the contract period." *Id.* In addition, the Subscription Strategy states:

> Some parties argue that BPA should show flexibility in the shape of the sales to the IOUs for their residential and small farm consumers. In determining the shape of sales to the IOUs, however, BPA must view the shape of all BPA sales to customers and the impact of the shape of such sales on BPA's system. BPA anticipates meeting substantial loads of preference customers which have shaping needs throughout the year. BPA cannot operate as economically or efficiently as desired if all loads have changing load shapes. There are operational benefits to BPA of customers taking energy around the clock, all year, without a significant

> amount of variation. Because BPA desires to operate its system efficiently, BPA is making this shape available to the IOUs. This will enable BPA to make direct power sales to the IOUs for their residential and small farm consumers while at the same time meeting the operational need of selling a significant flat-block of energy to regional loads. Further, BPA observes that its service to residential and small farm loads will be only a portion of the utility's total load, and such loads have baseload needs that BPA would be able to serve in this manner. It is important to note that the IOUs may request shaping services or other power products from BPA under the applicable rate schedule.

Id. at 46.

It is therefore clear that a 24-hour flat-block sale was precisely the type of product that the Subscription Strategy envisioned would be offered to IOUs in the proposed Residential Exchange settlements. BPA should therefore charge a price that applies to such a sale. This is what BPA has done. BPA's HLH and LLH energy rates (for both the RL and PF Preference rates) were derived by adjusting the monthly and diurnal energy prices from the Marginal Cost Analysis Study, WP-02-E-BPA-04, to assure that only the revenue requirement is collected. This is done because forecasted market energy prices would over-collect BPA's revenue requirement. Monthly HLH and LLH energy rates from the Marginal Cost Analysis Study, WP-02-E-BPA-04, were reduced proportionately until estimated revenues from energy charges equaled the balance of BPA's revenue requirement. Keep *et al.*, WP-02-E-BPA-17, at 14. During this process, the RL rate and the revenues forecasted under the RL rate were calculated assuming a flat annual load. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 94.

The IOUs argue that the shaped block offered to preference customers is a more valuable product than the 24-hour flat-block product offered to the IOUs. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 62. The IOUs argue that the 24-hour flat-block product has the lowest risk and lowest cost of service of all BPA products, while the shaped product follows load by the hour and the minute and has the highest risk and highest cost of service of any of the core Subscription products. *Id.* The IOUs argue that the 24-hour flat-block product is BPA's least expensive and most predictable product, because it has no hourly difference across the period of delivery. *Id.* They argue that, by contrast, shaped products present unpredictable variations in service obligations and subject BPA to market price exposure. *Id.* While BPA agrees that the way a customer takes power affects the value of that power, BPA disagrees with the IOUs' argument that the PF Preference and RL rates are dissimilar because of the products available under each. Providing shaped requirements service, *i.e.*, full and partial requirements service, does cost more to serve than a flat block. Keep *et al.*, WP-02-E-BPA-43, at 6. Nevertheless, the combination of the demand charge and the product-specific billing determinant equitably recovers the costs for these services. *Id.* A flat block and a shaped load pay different effective rates that reflect the different costs to serve. *Id.*

The IOUs argue that the PF and RL rates are based on the same demand and energy charges despite the fact that customers receiving flat-block power under the RL rate must incur additional costs to meet actual load. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 63. As stated above, lower-valued products purchased from BPA have lower costs than higher-valued products purchased from BPA. Any customer, whether an IOU or preference customer, taking a flat-block product would incur the same additional costs to meet actual load. In addition, as noted previously, the Subscription Strategy described the product that would apply to settlements of the REP with IOUs. This is a specific product with a specific rate for a specific settlement. As noted in BPA's testimony, the rate level for the settlement sales supports the proposed value of the settlement of the REP with regional IOUs. *See* Doubleday *et al*., WP-02-E-BPA-44, at 13.

In summary, the IOUs argue that the PF and RL rates are not approximately equal rates because the values of the products are not approximately equal. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 63. As noted above, a flat-block product purchased under the RL rate would cost an IOU exactly the same, on average, as a flat-block product purchased under the PF rate by a preference customer. The preference customer has the option to buy PF products of higher value, but only at a higher average price. BPA's rates are cost-based, however, and BPA's rate design philosophy is based on receiving revenues that are commensurate with the value of the product being sold. The IOUs also argue that the PF and RL rates do not satisfy BPA's statutory obligation to establish rates of general application for requirements loads of both preference and IOU customers and the residential exchange for IOUs. *Id.* As discussed in greater detail above, BPA has established rates of general application for BPA's requirements sales to preference customers at the PF Preference rate and for sales to exchanging utilities at the PF Exchange Program rate under section 7(b)(1) of the Northwest Power Act. Also as noted above, section 7(b)(1) of the Northwest Power Act does not relate to requirements sales to IOUs under section 5(b)(1) of the Northwest Power Act at rates established under section 7(f) of the Northwest Power Act, such as the RL rate. 16 U.S.C. §839c(f); 16 U.S.C. §839e(f). Finally, the price and product for the RL sales comprise the proper consideration for BPA's proposed settlements of the REP with the IOUs.

<u>Decision</u>

The PF and RL rates are approximately equal rates, because one must look at the nature of the product in establishing the rate. The 24-hour flat-block sale that is the basis of the Subscription settlement proposal with the IOUs is priced at the same rate that would be paid by a preference customer purchasing the same 24-hour flat-block service. BPA's rates satisfy BPA's statutory obligation to establish rates of general application for sales to requirements loads of preference customers and for sales to exchanging utilities.

14.3 <u>Proposed Subscription Settlements with Regional IOUs</u>

<u>Issue 1</u>

Whether the proposed Subscription settlements with IOUs waive the requirements of the Northwest Power Act.

Parties' Positions

PPC argues that the Northwest Power Act established the REP, and the statutory requirements may not be waived or otherwise administratively pardoned. PPC Brief, WP-02-B-PP-01, at 64. Alcoa/Vanalco argue that although the Administrator has discretion to enter into settlements, this discretion does not extend to changing the Northwest Power Act. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 92.

BPA's Position

The proposed IOU Subscription settlements have not yet been offered or executed. Such settlements are developed through a negotiation process and are not established in ratemaking proceedings conducted under section 7(i) of the Northwest Power Act. For ratemaking purposes, the general principles of the proposed settlements are consistent with the Northwest Power Act.

Evaluation of Positions

The PPC argues that the Northwest Power Act established the REP and, just as that right cannot be removed by administrative action, the statutory requirements may not be waived or otherwise administratively pardoned. PPC Brief, WP-02-B-PP-01, at 64. The PPC's specific arguments regarding the qualification of exchanging utilities for the proposed settlements are addressed in separate sections below. Alcoa/Vanalco argue that although the Administrator has discretion to enter into settlements, this discretion does not extend to changing the Northwest Power Act, citing *Morton v. Ruiz*, 415 U.S. 199, 237 (1974). Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 92. Alcoa/Vanalco correctly note that BPA has discretion to enter into settlements. Section 2(f) of the Bonneville Project Act provides that:

> Subject only to the provisions of this chapter, the Administrator is authorized to enter into such contracts, agreements, and arrangements, including the amendment, modification, adjustment, or cancellation thereof and the compromise or final settlement of any claim arising thereunder, and to make such expenditures, upon such terms and conditions and in such manner as [she] may deem necessary.

16 U.S.C. §832a(f). This authority was affirmed under section 9(a) of the Northwest Power Act. 16 U.S.C. §839f(a). *See Utility Reform Project v. Bonneville Power Admin.*, 869 F.2d 437, 442-443 (9th Cir. 1989).

It is important to note, however, that while the PPC and Alcoa/Vanalco claim that the proposed settlements are inconsistent with the Northwest Power Act, BPA has not yet offered or executed any of the proposed IOU Subscription settlements. Indeed, the proposed settlements are *not* being established in the current proceeding. This proceeding is only for the establishment of rates that apply to BPA's power sales for the next five-year rate period, beginning in FY 2002, and not the contracts that implement such sales. In developing rates over the past two decades, BPA has been able to rely on existing 20-year power sales contracts developed in 1981 to forecast its sales to customers for the next rate period. This is not the case in the current proceeding. BPA's existing power sales contracts will expire before the next rate period. Therefore, because existing contracts do not define BPA's future power sales obligations, BPA must forecast its power sales to customers for the upcoming rate period.

The proposed IOU Subscription settlements were first conceived in BPA's Power Subscription Strategy. The Subscription Strategy identified a number of basic proposed elements of the proposed settlements, but did not establish any settlements. These settlements are being negotiated with the interested IOUs, and then there will be a 30-day public comment period for all interested parties to advise BPA regarding the propriety of the proposed settlements, including the elements of the proposed settlements that PPC and Alcoa/Vanalco have identified in this rate case. After reviewing the parties' comments, the Administrator will determine whether it is appropriate to enter into the proposed settlement agreements. In developing rates, BPA must forecast sales to customers using the best information available. Because BPA has proposed to offer the IOU Subscription settlements but has not yet offered such settlements, BPA must forecast whether sales to IOUs would likely be made under those settlements. BPA's assumptions regarding the proposed settlement sales are reflected elsewhere in this ROD. While this is not the forum in which BPA will finally determine whether the proposed settlements comply with law, and a separate public process is being held to address such issues, BPA believes that the proposed settlements comply with law and will address the parties' claims.

With regard to Alcoa/Vanalco's argument that although the Administrator has discretion to enter into settlements, this discretion does not extend to changing the Northwest Power Act, *see* Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 92; BPA does not believe that a conflict exists. The proposed settlements do not change the Northwest Power Act. Further, *Morton v. Ruiz* dealt with the issue of whether an agency's statutory interpretation was consistent with Congressional intent. *Id.* In the present case, BPA is not proposing any interpretation of the Northwest Power Act that is inconsistent with the intent of Congress in establishing the REP. BPA is simply proposing to offer settlements of that program as it has done over the last two decades. As noted in BPA's testimony, "[b]eginning in 1981, BPA and exchanging utilities executed RPSAs for 20-year terms. Between 1981 and today, all of these RPSAs have been settled except for one, which is between BPA and a utility in deemer status." Leathley *et al.*, WP-02-E-BPA-19, at 10-11. Again, the agency's final determination of whether any actual settlements are consistent with law will be made in a separate forum.

Alcoa/Vanalco argue that there is nothing in the Northwest Power Act that indicates that the REP will terminate or that the IOUs have the authority to settle the benefits of the REP on behalf of their residential consumers, especially in a way that would reduce or end those benefits. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 92. BPA's settlement proposal does not propose to terminate the REP. The proposal simply settles the implementation of the program for participating utilities for a limited amount of time in return for appropriate consideration. The REP continues to exist for those that do not execute settlements and may continue to be implemented in its traditional form at the time any settlements expire. Contrary to the IOUs settling participation in the exchange in a way that would reduce or end those benefits, the proposed settlements are forecasted to provided greater benefits than the traditional implementation of the Exchange (compare Tr. 122 with Wholesale Power Rate Development

Study Documentation, WP-02-E-BPA-05A, at 91), although BPA has acknowledged that there are variables that could increase exchange benefits during the rate period.

With regard to whether the IOUs have the authority to settle the benefits of the REP for a limited period on behalf of their residential consumers, this is supported, as noted above, by the fact that some 21 exchanging utilities, all but one, have executed settlements over the past two decades. Leathley *et al.*, WP-02-E-BPA-19, at 10-11. In addition, the Northwest Power Act provides that the REP is implemented through contractual agreements between BPA and its utility customers. 16 U.S.C. §839c(c)(1). While benefits are passed through to residential consumers, the contractual relationship that enables the program is between BPA and the utility. The utility is a sophisticated entity with greater knowledge of the implementation of the exchange than the general public. In addition, state public utility commissions regulate IOUs. These commissions are directly involved in the REP because they establish the rate credit for the REP that is incorporated in a utility's retail rates. IOUs cannot simply discard benefits that must flow to its consumers as expressly required by law, 16 U.S.C. §839c(c)(3), particularly given the tremendous interest that state commissions take in the oversight and provision of such benefits to consumers.

Alcoa/Vanalco argue that BPA cannot settle before determining the facts through this rate case, because BPA cannot assess the prudence of the settlement in a reverse fashion. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 92. As noted above, BPA has not settled the REP with the IOUs. Such settlements can occur only after negotiations with interested IOUs have concluded and BPA's public comment process on the proposed settlements has concluded. BPA must establish rates at this time, however, in order to develop rates in a timely manner and to allow customers to review BPA's proposed rates in the consideration of whether they wish to purchase power from BPA. While this means that BPA will not have perfect knowledge of its power sales in the next rate period, BPA has always been required to forecast such sales for purposes of developing rates. BPA, however, is addressing the issues raised by the parties on this matter.

Alcoa/Vanalco argue that BPA's decision to settle the REP as BPA sees fit is contrary to one of the purposes of the Northwest Power Act, which is to eliminate rate disparity between residential customers in the PNW served by preference customers and those served by the IOUs. *Id.*; *Central Electric Cooperative v. BPA*, 835 F.2d 199,200 (9th Cir. 1987). *Central Electric Cooperative*, however, does not state that elimination of *retail* rate disparity is one of the purposes of the Northwest Power Act. *Id.* Instead, this case recognized that a rate disparity grew between the retail rates paid by the customers of IOUs and the customers of publicly owned utilities, and that the REP subsidizes the rates of the exchanging utilities. *Id.* The Northwest Power Act does not state that its purpose is to eliminate the disparity of *retail* rates. The REP was established to provide IOUs a form of access to the benefits of the Federal system. This program allows IOUs to pay the same wholesale rate for power from BPA, the PF power rate, as paid by BPA's publicly owned customers, subject to the 7(b)(2) rate test. 16 U.S.C. §839e(b)(1); 16 U.S.C. §839e(b)(2). This is the rate parity provided by the Northwest Power Act. In addition, as noted above, the proposed settlements are forecasted to provided greater benefits than the traditional implementation of the exchange. Finally, the proposed settlements would not contradict the intent of the Northwest Power Act in any event, because the settlements would still provide benefits that must be passed through directly to the IOUs' residential and small farm consumers. Alcoa/Vanalco argue that contrary to BPA's assertion, the primary purpose of the REP was not to benefit the IOUs, but to secure the benefits of cost-based BPA power for the residential and small farm customers of the IOUs by eliminating the rate disparity these consumers faced compared to the same class of consumers served by BPA's preference customers. Alcoa/Vanalco have misstated BPA's position. BPA has always maintained that the purpose of the REP was to provide a form of access to Federal power for the residential and small farm customers of exchanging utilities. The REP, however, is implemented through the utilities. Alcoa/Vanalco cite a passage from *PacifiCorp v. Fed. Energy Regulatory Comm'n*, 795 F.2d 816, 818 (9th Cir. 1986). When this quotation is viewed in context, it does not support Alcoa/Vanalco's claim. The court stated:

> Under the exchange system contemplated by section 5, each electric utility in the Northwest may elect to sell power to BPA at the "average system cost [ASC] of [a] utility's resources." 16 U.S.C. §839c(c)(1); see also 16 U.S.C. §839a(19) (defining "resource"). BPA then sells the same amount of power back to the utility at BPA's lower wholesale rate. This enables the utility to sell power to its residential customers at the priority rate given to residential consumers receiving BPA federal power. In reality the exchange is a paper transaction. It is designed to eliminate the disparity that developed between the rates paid by residential customers of the IOUs and the lower rates paid by residential customers of publicly owned utilities.

Id. The court's statement contains a number of factual errors. For example, the court states that "[t]his enables the utility to sell power to its residential customers at the priority rate given to residential consumers receiving BPA federal power." First, the utility does not sell power to its residential customers at the priority rate given to residential consumers receiving BPA Federal power. Indeed, residential customers do not pay a BPA rate for power. BPA sells power to the utility. The utility then develops its retail rates, which include expenses in addition to the cost of power at BPA's PF rate, and those retail rates are used to sell power from the utility to the residential consumer. Another factual error is the statement that the Exchange program is "designed to eliminate the disparity that developed between the rates paid by residential customers of the IOUs and the lower rates paid by residential customers of publicly owned utilities." A simple review of the Act's provisions regarding the REP shows that the Exchange does not necessarily eliminate the disparity between retail rates of IOUs and preference customers. BPA pays a subsidy to the exchanging utility based on the difference between the utility's ASC and BPA's PF Exchange rate. This amount of dollars is used to lower the retail electric bills of the consumers of exchanging utilities. The IOUs' retail rates, however, may be at a completely different level than the retail rates of a preference customer. Indeed, which retail rate of which customer could the court be referring to? Each preference customer has different retail rates, just as every IOU has different retail rates. Therefore, the REP does not eliminate retail rate disparity. Furthermore, there are some preference customers with *higher* retail rates than IOUs. The purpose of the REP was not to create parity between the residential rates of preference and exchanging customers, but rather to provide exchanging customers greater access to BPA's low-cost power. As noted previously, the term "wholesale rate parity" means exactly what it says: parity of wholesale rates charged by BPA to its preference and exchange customers. This is achieved in the Northwest Power Act by providing that the wholesale power rates for

BPA's sales to its preference customers and the wholesale power rates for BPA's sales to IOUs for the REP will be at the same rate, that is, the PF rate. This basic point, however, is not always true, because the Northwest Power Act also includes 7(b)(2), which can result in an allocation of costs such that the PF rate paid by exchanging utilities is higher than the PF rate paid by preference customers.

Alcoa/Vanalco argue that the proposed Residential Exchange settlements violate the Northwest Power Act because the 1,000 aMW sale to the IOUs does not does not fit into one of the allowed classes of power sales under that Act. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 44. This is incorrect. BPA may sell power to the IOUs under a number of authorities. BPA can sell firm net requirements power to the IOUs pursuant to section 5(b) of the Northwest Power Act. 16 U.S.C. §839c(b). BPA can sell in-lieu power to the IOUs pursuant to section 5(c). 16 U.S.C. §839c(b). BPA can sell additional power to the IOUs pursuant to section 5(f). 16 U.S.C. §839c(b). The proposed settlement sales are proposed to be net requirements sales under section 5(b) of the Northwest Power Act and therefore fit into one of the allowed classes of power sales under that Act.

Alcoa/Vanalco argue that the Residential Exchange settlement violates the intent of the Northwest Power Act that the IOU residential and small farm customers receive the same benefits from the Federal system as preference customers. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 44. Alcoa/Vanalco cite no authority for this proposition. There is no statutory requirement that the IOUs receive the same benefits from the Federal system as preference customers. Alcoa/Vanalco argue that under the settlement, IOU residential and small farm consumers will be provided greater benefits than the traditional implementation of the Exchange. *Id.* Similarly, PPC argues that BPA's proposed settlements should not provide the IOUs with more rights than are available under statute. PPC Ex. Brief, WP-02-R-PP-01, at 18. PPC also argues that settlement offers should be made only to those IOUs that qualify, given current methodologies and assumptions, for the Residential Exchange in this rate proceeding. *Id.* As noted in greater detail below, BPA has established that there are a number of variables that may affect and increase potential Residential Exchange benefits for the IOUs, and it is appropriate that these variables be taken into consideration in determining the consideration for the settlement. Boling and Doubleday, WP-02-E-BPA-53, at 20.

Alcoa/Vanalco note BPA's statements that the proposed Residential Exchange settlements are not being established in the rate case and that for ratemaking purposes, the general principles of the proposed settlements are consistent with the Northwest Power Act. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 43. Alcoa/Vanalco argue that the proposed terms of the settlements are contrary to section 7(i) of the Northwest Power Act because they have a direct impact on rates, yet parties were not permitted to comment on these topics in the rate case. *Id.* This argument is not persuasive. BPA establishes rates in a hearing consistent with section 7(i) of the Northwest Power Act. 16 U.S.C. §839e(i). BPA is not required to negotiate its contracts in a section 7(i) hearing. As noted previously, BPA has not settled the REP with the IOUs. Such settlements can occur only after negotiations with interested IOUs have concluded and BPA's public comment process on the proposed settlements has concluded. BPA must establish rates at this time, however, in order to develop rates in a timely manner and to allow customers to review BPA's proposed rates in the consideration of whether they wish to purchase power from BPA. While this means that BPA will not have perfect knowledge of its power sales in the next rate period, BPA has always been required to forecast such sales for purposes of developing rates. For example, a virtually identical situation arose in 1981 when BPA was conducting negotiations with its customers for power sales contracts for the next (20-year) contract period. At the same time, BPA was establishing rates that would apply to sales under the contracts. BPA properly held the rate case despite the fact that the terms and conditions of the power sales contracts and RPSAs were not known and the parties could not address the contract terms in the rate case. The Administrator noted that "BPA had to consider the rate impacts of new power sales contracts, which were being negotiated with customers in separate proceedings but simultaneously with the rate hearings. The scope of the contracts and the costs of power that would be sold by BPA to its various types of customers under the new agreements *had to be projected* and taken into account in the setting of the new rates." Administrator's ROD, 1981 Transmission Rate Proposal and 1981 Wholesale Power Rate Proposal, June 1981, at i-ii (emphasis added). Additional responses to scope issues are contained in Chapter 18 of this ROD.

Alcoa/Vanalco also note BPA's statement that the proposed IOU settlements are forecasted to provide greater benefits than the traditional implementation of the Exchange. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 44. *See also* PPC Ex. Brief, WP-02-R-01, at 17. Alcoa/Vanalco, however, ignore the more detailed discussion of this issue. BPA also noted that the determination of whether a settlement for a particular IOU is appropriate will be made by BPA after negotiations with the relevant utility and after BPA's public comment process on the proposed settlement. The final decision of whether a particular settlement is excessive or insufficient will be made in that separate forum and not in the current rate case. Furthermore, BPA has established that there are a number of variables that affect potential Residential Exchange benefits for the IOUs. Boling and Doubleday, WP-02-E-BPA-53, at 20. For example, the issue of deemer balances has not yet been resolved. *Id.* If such deemer balances did not exist or were small, this would not be an impediment to receiving benefits. *Id.* Also, while BPA has used the current ASC Methodology for its rate case forecasts, the methodology could be revised. *Id.* If the methodology is revised and exchanging utilities are allowed to exchange greater costs, this would increase their ASCs and exchange benefits. *Id.* Furthermore, in-lieu transactions are dependent on resources available at lower cost than the utilities' ASCs. *Id.* Increases in market prices could reduce BPA's ability to conduct in-lieu transactions. *Id.* Also, the IOUs contest a number of assumptions BPA made in developing the proposed PF Exchange Program rate. *Id.* If BPA retains those assumptions and the IOUs successfully challenge that rate, the rate could be reduced and exchange benefits increased. *Id.* While BPA developed its 2002 power rates based on the best information available, BPA recognizes that there are variables that could allow all IOUs to receive substantial exchange benefits. *Id.*

Decision

The proposed IOU Subscription settlements have not yet been offered or executed. Such settlements are developed through a negotiation and public comment process and are not established in ratemaking proceedings conducted under section 7(i) of the Northwest Power Act. Issues regarding the consistency of the settlements with the Northwest Power Act will be addressed and determined after the public process conducted for the review of the proposed settlements. For purposes of the rate case, however, and as discussed in greater detail in this *section, BPA has determined that the proposed settlements comply with the Northwest Power Act. BPA reasonably forecasted sales under the proposed settlements.*

Issue 2

Whether IOUs' net requirements are properly considered in the proposed IOU Subscription settlements.

Parties' Positions

Alcoa/Vanalco argue that part of the proposed settlement is a sale of power from BPA to the IOUs to meet part of their net requirements, but BPA does not know the IOUs' needs in the way of net requirements. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 92. Alcoa/Vanalco argue that this would be arbitrary and capricious, and Federal agencies are not allowed to make decisions that violate the law. *Id.*

BPA's Position

The proposed IOU Subscription settlements have not yet been negotiated or executed. Such settlements are developed through a negotiation process and a public review process and are not established in ratemaking proceedings conducted under section 7(i) of the Northwest Power Act. BPA will not sell requirements power to IOUs that do not have a sufficient net requirement to purchase such power.

Evaluation of Positions

Alcoa/Vanalco argue that several of the individual components of the proposed exchange settlements violate the law. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 92. Alcoa/Vanalco argue that part of the proposed settlement is a sale of power from BPA to the IOUs to meet part of their net requirements, but BPA has not recently sold requirements power to the IOUs and does not know the IOUs' needs in the way of net requirements. *Id.* at 93. Alcoa argues that BPA has not yet finalized its "section5(b)/9(c) Policy," and as a result neither BPA nor the IOUs know what the IOUs' total net requirement demand will be during the rate period. *Id.* First, BPA's Subscription Power Sales to Customers and Customer's Sales of Firm Resources (policy for determining net requirements) was published on March 16, 2000. *See* BPA's Subscription Power Sales to Customers and Customer's Sales of Firm Resources, 65 Fed. Reg. 52, 14259-14265 (2000). The policy is, therefore, available to help in the determination of the net requirements of the IOUs. With regard to the argument that BPA does not know the IOUs' total net requirement demand for the rate period, this issue is addressed below. As noted previously, BPA has not yet offered or executed any of the proposed IOU Subscription settlements. Indeed, the proposed settlements are not being established in the current proceeding. This proceeding is only for the establishment of rates that apply to BPA's power sales for the next five-year rate period, beginning in FY 2002, and not the contracts that implement such sales. These settlements will be negotiated with the interested IOUs, if any, and then there will be a 30-day public comment period for all interested parties to advise BPA regarding the propriety of the proposed settlements, including arguments regarding whether the IOUs have established any necessary net requirements. After reviewing the parties' comments, the Administrator will determine whether it is appropriate to enter into the proposed settlement agreements.

In developing rates, BPA must forecast sales to customers using the best information available. Because BPA has proposed to offer the IOU Subscription settlements but has not yet offered such settlements, BPA must forecast whether sales to IOUs would likely be made under those settlements. The total amount of benefits in the proposed IOU settlements is the equivalent of 1,800 or 1,900 aMW of power. BPA has forecasted it will offer the IOUs 1,000 aMW of firm power. The remaining 800 or 900 aMW of settlement benefits are forecasted to be in the form of monetary payments. The 1,000 aMW of power is not designated for any one utility, but would be shared by the IOUs that had established net requirements for the amount of their purchases. While these individual amounts are determined in the contract negotiations and public comment process, it is reasonable to assume that the IOUs would collectively have 1,000 aMW of net requirements. BPA forecasted 1,000 aMW of requirements sales to the IOUs during the rate period: "[f]or purposes of this Study, BPA assumes power sales to IOUs of 1,000 aMW. *See* [Loads and Resources Study, WP-02-E-BPA-01] Appendix A, Tables 6 through 10. This sales forecast assumes each of the region's IOUs participates in the REP settlement. . . . BPA assumes that Subscription power sales to the IOUs will be made as requirements sales under section 5(b) of the [Northwest Power Act] at the proposed RL rate or as 'in lieu' sales under section 5(c) of the Northwest Power Act at the proposed PF Exchange Subscription rate." Loads and Resources Study, WP-02-E-BPA-01, at 5. In any event, however, it would not matter if the IOUs have requirements that are larger or smaller than 1,000 aMW. BPA would sell power to the IOUs only within their net requirements, and if a utility could not establish a sufficient net requirement, it would not receive power but would have to receive the remaining portion of its settlement amount in the form of monetary benefits. For ratemaking purposes, the costs of the power and monetary forms of benefits are the same, so the election of one form of benefit or another does not matter.

Alcoa/Vanalco argue that possibly at least one regional IOU has no net requirements based on recent power marketing activities, yet because there is no section5(b)/9(c) Policy in place, its net requirements may not become identified until long after it has accepted requirements power sales from BPA. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 93. This circumstance will not occur. BPA's Subscription Power Sales to Customers and Customer's Sales of Firm Resources (policy for determining net requirements) was released on March 16, 2000. *See* BPA's Subscription Power Sales to Customers and Customer's Sales of Firm Resources, 65 Fed. Reg. 52, 14259-14265 (2000). The policy is therefore available to help in the determination of the net requirements of the IOUs. An obvious prerequisite for any requirements sale is the establishment of a utility's net requirements. BPA will not make net requirements sales to IOUs before BPA has determined their net requirements.

Alcoa/Vanalco argue that BPA is proposing to sell power without knowing whether any of the IOUs have net requirements. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 93. Alcoa argues that such a decision is arbitrary and capricious, citing *Motor Vehicles Mfrs. Assn. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). *Id.* Again, Alcoa misunderstands what BPA is doing. A proposal to sell power is just that, a proposal. BPA's proposal is not an offer to sell power. BPA is negotiating settlement contracts with the IOUs and will hold a public comment process before executing any requirements firm power sales. The record established in the Subscription Strategy supported a proposed settlement offer to the IOUs of benefits equivalent to 1,800 aMW of power in consideration for settlement of the REP--1,000 aMW in power, and 800 aMW in monetary benefits. This is reflected in the record developed in the current rate case. The final determination of a utility's net requirements, however, occurs in a forum outside the rate case. As noted previously, for rate case purposes BPA forecasted that collective IOU requirements would permit 1,000 aMW of requirements sales to IOUs. BPA will not sell requirements power to an IOU unless it has established a net requirement. Also, for ratemaking purposes, an IOU's election of power or monetary benefits in the 1,800 or 1,900 aMW of total benefits does not affect the development of BPA's rates. Therefore, the fact that BPA does not know a utility's final net requirement at this time does not make BPA's forecast of potential sales to such utility arbitrary or capricious. Alcoa/Vanalco argue that Federal agencies are not allowed to make substantive decisions if they have reason to believe that those decisions would violate the law. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 93. As explained previously, BPA is not determining the IOUs' final net requirements in this forum and has no reason to believe that its proposed actions would violate the law.

Decision

The proposed IOU Subscription settlements, including final determinations of net requirements, have not yet been offered or executed. Such settlements are developed through a negotiation process and are not established in ratemaking proceedings conducted under section 7(i) of the Northwest Power Act. BPA will not sell requirements power to IOUs that do not have a sufficient net requirement to purchase such power. For ratemaking purposes, BPA has reasonably forecasted 1,000 aMW of requirements sales to IOUs.

Issue 3

Whether deemer balances are properly reflected in the proposed settlements.

Parties' Positions

PPC argues that IOUs that have deemer balances should not receive cash benefits from the IOU Subscription settlements until they have paid their deemer balances. PPC Brief, WP-02-B-PP-01, at 66; PPC Ex. Brief, WP-02-R-PP-01, at 18. Alcoa/Vanalco argue that the existing power contracts between the IOUs and BPA require that the IOUs work off the deemer balances before BPA enters a new contract. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 94.

BPA's Position

The existence of deemer balances and the amount of such balances, if any, must be determined in negotiations between BPA and the IOUs. Boling and Doubleday, WP-02-E-BPA-53, at 19. This decision cannot be made in the rate case. *Id.* BPA's current assumption for ratemaking purposes is that such balances, if any, will be held in abeyance during the IOU Subscription settlement term. *Id.*

Evaluation of Positions

The PPC argues that IOUs that have deemer balances should not receive cash benefits from the settlements until they have paid their deemer balances. PPC Brief, WP-02-B-PP-01, at 66; PPC Ex. Brief, WP-02-R-PP-01, at 18. Alcoa/Vanalco argue that BPA is proposing to settle the REP with three utilities that have large deemer balances. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 94. Alcoa/Vanalco argue that BPA intends to settle with these utilities now and worry about their deemer balances later, but the existing power contracts between the IOUs and BPA require that the IOUs work off the deemer balances before BPA enters a new contract. *Id.* Alcoa/Vanalco argue that BPA intends to ignore this requirement. *Id.* BPA disagrees with the parties' arguments. BPA's estimates of IOU deemer balances are BPA's preliminary calculations and have not been discussed with or verified by the IOUs. Boling and Doubleday, WP-02-E-BPA-53, at 19. In fact, the IOUs contest BPA's calculation of the deemer balances. *Id.* The existence of deemer balances and the amount of such balances, if any, must be determined in negotiations between BPA and the IOUs and will not be finally determined until BPA and the IOUs have discussed and resolved the issue or the issue is resolved through litigation. *Id.* This decision cannot be made in the rate case. *Id.* BPA's current assumption for ratemaking purposes is that such balances, if any, will be held in abeyance during the settlement term. *Id.*

Contrary to Alcoa/Vanalco's characterization, BPA is not intending to simply settle with these utilities now and worry about the problem later. *See* PPC Ex. Brief, WP-02-R-PP-01, at 18. The deemer balances, if any, are not being forgiven by BPA. A settlement, by its very nature, is a settlement of all the issues pending between two parties regarding a particular subject matter. BPA believes that it is appropriate to assume for ratemaking purposes that the parties will include the issue of deemer balances within the proposed settlements and will hold the balance in abeyance during the term of the settlement. If utilities resume the traditional REP after the term of the settlement, the deemer issue must be resolved before the utility executes a new RPSA. Alcoa/Vanalco argue that BPA is required to operate in a business-like manner and that alleged deemer balances may be realized by BPA only at the end of the current contract period. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 45. Alcoa/Vanalco argue that BPA provides no stated purpose for not seeking to recover the alleged balances before or as part of the Residential Exchange settlements. *Id*. Alcoa/Vanalco have apparently ignored the reasons stated for BPA's position on deemer balances in this section. As noted previously and subsequently, BPA's reasons to hold any alleged deemer balances in abeyance include the preliminary nature of the alleged deemer balances; the fact that the alleged deemer balances have not been discussed with or verified by the IOUs; the fact that the IOUs contest BPA's calculation of the deemer balances; that the existence of deemer balances and the amount of such balances, if any, must be determined in negotiations between BPA and the IOUs and will not be finally determined until BPA and the IOUs have discussed and resolved the issue or the issue is resolved through litigation; and that a settlement, by its very nature, is a settlement of all the issues pending between two parties regarding a particular subject matter, including, in this case, deemer balances.

Alcoa/Vanalco argue that the existing power contracts between the IOUs and BPA require that the IOUs work off the deemer balances before BPA enters a new contract. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 94. While this issue cannot be resolved in the rate case and will be addressed in the development of the proposed settlement agreements, the contract language is not as clear as implied by Alcoa/Vanalco. Section 10 of the 1981 RPSAs provides in pertinent part that "[u]pon termination of this agreement, any debit balance in such separate account shall not be a cash obligation of the Utility, but shall be carried forward to apply to any subsequent exchange by the Utility for the Jurisdiction under any new or succeeding agreement." (Emphasis added.) While BPA is not resolving this issue at this time, it is reasonable to assume for ratemaking purposes that the contract language refers to a subsequent "exchange" agreement, that is, an agreement that continues the traditional exchange of power between BPA and the utility at the respective PF Exchange and ASC rates. The proposed IOU Subscription settlement agreements; however, do not include the traditional exchange of power from the utility with power from BPA, but rather, are a payment of consideration for the termination of participation in the REP. It is appropriate in such circumstances to hold deemer balances, if any, in abeyance during the term of the settlement agreement.

Decision

BPA has properly forecasted that deemer balances will be held in abeyance for IOUs that execute Subscription settlements of the REP.

Issue 4

Whether eligibility to participate in and receive benefits from the REP is properly reflected in the proposed IOU Subscription settlements.

Parties' Positions

The PPC argues that the IOU settlement offer was made irrespective of individual IOU qualifications for, and eligibility to participate in, the REP, such that BPA has made an administrative offer in settlement of statutory rights that in some cases exceeds the statutory right available to an individual IOU. PPC Brief, WP-02-B-PP-01, at 66. Alcoa/Vanalco argue that BPA proposes to confer benefits on MPC even though MPC: (1) divested all of its generating assets in December 1999; and (2) announced it will have no obligation to serve in the post-2002 period. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 94.

BPA's Position

BPA believes there are a number of variables that affect potential Residential Exchange benefits for the IOUs. Boling and Doubleday, WP-02-E-BPA-53, at 20. While BPA developed its 2002 power rates based on the best information available, BPA recognizes that these variables could allow all IOUs to receive substantial Residential Exchange benefits. *Id.*

Evaluation of Positions

The PPC argues that the IOU settlement offer was made irrespective of individual IOU qualifications for, and eligibility to participate in, the REP, such that BPA has made an administrative offer in settlement of statutory rights that in some cases exceeds the statutory right available to an individual IOU. PPC Brief, WP-02-B-PP-01, at 66. First, it must be noted that the determination of whether a settlement for a particular IOU is appropriate will be made by BPA after negotiations with the relevant utility and after BPA's public comment process on the proposed settlement. The final decision of whether a particular settlement is excessive or insufficient will be made in that separate forum and not in the current rate case. Furthermore, the determination of prospective participation in the REP is not as clear as suggested by PPC. As BPA has established, there are a number of variables that affect potential Residential Exchange benefits for the IOUs. Boling and Doubleday, WP-02-E-BPA-53, at 20. As just discussed, the issue of deemer balances has not yet been resolved. *Id.* If such deemer balances did not exist or were small, this would not be an impediment to receiving benefits. *Id.* Also, while BPA has used the current ASC Methodology for its rate case forecasts, the methodology could be revised. *Id.* If the methodology is revised and exchanging utilities are allowed to exchange greater costs, this would increase their ASCs and exchange benefits. *Id.* Furthermore, in-lieu transactions are dependent on resources available at lower cost than the utilities' ASCs. *Id.* Increases in market prices could reduce BPA's ability to conduct in-lieu transactions. *Id.* Also, the IOUs contest a number of assumptions BPA made in developing the proposed PF Exchange Program rate. *Id.* If BPA retains those assumptions and the IOUs successfully challenge that rate, the rate could be reduced and exchange benefits increased. *Id.* While BPA developed its 2002 power rates based on the best information available, BPA recognizes that there are variables that could allow all IOUs to receive substantial exchange benefits. *Id.*

PPC notes BPA's statement that there are a number of variables that affect a utility's ability to receive Residential Exchange benefits, including that there may be a change in the ASC Methodology during the rate period, which could increase exchanging utilities' benefits. PPC Ex. Brief, WP-02-R-PP-01, at 18. PPC argues that this argument is facetious, because BPA asserts in its Subscription Strategy that "the current ASC Methodology will be used for any Residential Exchange forecasts." *Id*., citing Subscription Strategy at 10. This argument is not "facetious." BPA's Subscription Strategy noted that, for the rate case, BPA would, in its initial proposal, propose to use the current ASC Methodology for Residential Exchange forecasts. Indeed, in the rate case BPA found it appropriate to use the current ASC Methodology for Residential Exchange forecasts. This is perfectly consistent, however, with BPA's recognition that a new ASC Methodology could be established during the rate period that could increase exchanging utilities' benefits. While BPA does its best to make forecasts, BPA must recognize that there are things that BPA cannot now determine with certainty.

Alcoa/Vanalco argue that BPA proposes to confer benefits on MPC even though MPC: (1) divested all of its generating assets in December 1999; and (2) announced it will have no obligation to serve in the post-2002 period (Tr. 1571, lines 17-23; Tr. 1680, line 24; Tr. 1681, line 3. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 94. Alcoa/Vanalco argue that BPA does not yet know how it will supply any benefits obtained from the settlement to a utility that has no power supply costs, Tr. 1571, line 17, through 1575, line 2. *Id.* First, Alcoa/Vanalco's citations to the record do not precisely correspond with their characterizations of the testimony. The transcript citations in support of the claim that MPC announced that it will have no obligation to serve in the post-2002 period do not reference FY 2002 or any other year but note that it was the witness's "impression" that MPC did not intend to remain in the power supply business.

Tr. 1681, lines 2-3. A utility's intent may not coincide with what a utility is required to do by law. In addition, as noted previously, these types of issues are issues that will be addressed in the negotiation of the IOU Subscription settlement agreements. The proposed settlement agreements would then be subject to a public process where interested parties could raise issues regarding the proposed settlements, including the issue identified by Alcoa/Vanalco.

For ratemaking purposes, BPA believes it is reasonable to include a forecast of settlement benefits to MPC in the rate case for a number of reasons. For example, Alcoa/Vanalco fail to note a number of significant points regarding MPC. Regardless of whether or not BPA has a policy for serving utilities that may have divested resources, there is a substantial basis for assuming that MPC would continue to have an obligation to serve residential loads during the rate period. MPC may have an obligation to serve, in which case it would have to acquire resources or use the resources it sold pursuant to a contract right. First, under Montana law, by default MPC continues to 2002 to supply retail load or consumers that do not elect to purchase from other suppliers. Mont. Code Ann. section 69-8-201(1)(b); *Id.* at (3); section 69-8-103(25). In addition, the law allows the public utilities commission to extend to 2004 the transition period wherein MPC would likely continue as the default supplier. Mont. Code Ann. section 69-8-201(2)(a). In addition, the State of Montana has passed a statute establishing a default supplier that will serve residential loads. Mont. Code Ann. section 39-19-101 to 315. While MPC or another entity may become the default supplier under that statute at any time, there is no requirement to establish a default supplier under that statute until the end of the transition period under the Montana restructuring statute. Mont. Code Ann. section 39-19-103. Where MPC is the default supplier, it would be an exchanging utility serving residential load during the rate period. It would, therefore, be a proper participant in an exchange settlement.

While Alcoa/Vanalco question how benefits obtained from the settlement would be provided to a utility that has no power supply costs, MPC would need to acquire power to serve its load obligations. MPC would then have power supply costs. Such costs could be the basis for MPC's proposed ASC. Finally, as noted above, Alcoa/Vanalco admit that MPC has an obligation to 2002, which is within the rate period. BPA's Subscription Strategy proposes that the exchange settlement benefits must be able to be assigned to the party serving the residential load. *See* Subscription Strategy at 9. Thus, even if MPC were no longer the supplier, it is likely that another eligible entity would be able to have the settlement benefits assigned to them.

Alcoa/Vanalco argue that MPC has announced that it will sell its transmission assets and expects to be out of the power supply business within one to one and one-half years. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 45-46. Alcoa/Vanalco have not identified any record support or other authority for this proposition. In any event, however, BPA understands that MPC plans to make MPC a subsidiary of Touch America and sell the company stock for the subsidiary to new owners. Sale of the company through a stock sale would transfer the existing obligations of the company under Montana statutes to the new owner. Alcoa/Vanalco also argue that BPA's reliance on Montana law for the proposition that MPC has a continuing obligation to serve as the default supplier misconstrues the present state of the electricity market and law in Montana. *Id.* BPA disagrees. Montana's restructuring statute requires MPC or its successor to provide a default supply service during a transition period through 2002. The public service commission may extend such transition period until 2004 under the statute. While the public service commission is authorized by a subsequent statute to appoint another entity as the default supplier other than MPC, they are not required to make such appointment until the end of the transition period in the restructuring statute. Alcoa/Vanalco argue that at this time, the Montana Public Service Commission has not designated a permanent default supplier and MPC has made clear by its actions (sale of power and transmission assets) that it cannot and will not be designated as the default supplier. *Id*. BPA disagrees with Alcoa/Vanalco that MPC has made it clear by its actions that MPC or its successor will not be serving residential load during the period starting October 1, 2001. While MPC management has made clear its obligation to change managers and owners of MPC, the successors to the company will have the obligation to serve the current residential consumers of MPC. There is a high likelihood that the PSC will ultimately select the owner of the distribution system, *i.e.*, MPC's successor, as the default supplier for MPC's current residential consumers. BPA believes MPC still represents the interests of MPC's residential consumers under Montana statutes until it transfers ownership of the company. There are still many unresolved issues around the sale of the company that could result in the sale not being closed.

Given Alcoa/Vanalco's previous arguments, they argue that BPA has no reasonable basis to assume that MPC will be in any position to receive the Residential Exchange settlement proceeds and pass them on to any eligible customer. *Id*. BPA disagrees with Alcoa/Vanalco's characterization of the current situation. MPC still has obligations to its residential consumers under Montana law. BPA has no evidence that MPC does not intend to fulfill those obligations. It is reasonable for BPA to believe that MPC or any successor will meet the needs of the residential consumers of Montana. Further, Alcoa/Vanalco argue that there is no evidence that any successor to MPC would be eligible to receive these proceeds. *Id*. The eligibility of a successor to MPC to receive benefits under the REP is a statutory question. BPA believes the intent of Congress under section 5(c) is that benefits of the Federal Columbia River Power System are intended to flow to residential consumers. Congress established the REP in a manner that the benefits flowed to those consumers through their electricity supplier. BPA believes that "Pacific Northwest electric utilities" for purposes of section 5(c) are those entities serving the residential and small farm loads of the region as authorized by state law or order of the applicable state regulatory authority. BPA sees no intent of Congress to exclude residential consumers from receiving the benefits of the FCRPS based on how a state structures its electric power industry, and no evidence to conclude that any successor to MPC would be ineligible to receive Residential Exchange settlement proceeds. Alcoa/Vanalco argue that BPA's decision to include the cost of any Residential Exchange settlement with MPC in BPA's revenue requirement in this rate case is not supported by the record. *Id*. To the contrary, BPA's legal and other analysis of this issue has been addressed previously. Furthermore, Alcoa/Vanalco have presented no evidence that residential consumers of MPC will cease to exist or that those consumers will not be eligible for benefits under the REP. BPA believes MPC still represents the interests of MPC's residential consumers under Montana statutes until it transfers ownership of the company. MPC is still capable of entering a contract on behalf of those consumers.

Decision

While BPA has developed its 2002 power rates based on the best information available, BPA recognizes that there are variables that could allow all IOUs to receive substantial Residential Exchange benefits. BPA properly reflected an amount of settlement benefits for MPC.

Issue 5

Whether BPA has properly reflected in ratemaking the possible increase in proposed IOU Subscription settlement benefits from 1,800 to 1,900 aMW.

Parties' Positions

The PPC argues that BPA's other customers should not bear the cost of the extra 100 aMW of IOU benefits that BPA is currently considering, suggesting either a 1,800 aMW limit on settlement benefits or purchasing and melding the cost of 100 aMW in the IOUs' rates. PPC Brief, WP-02-B-PP-01, at 67; PPC Ex. Brief, WP-02-R-PP-01, at 18-19. SUB argues that the proposed sales of an additional 100 aMW at a PF equivalent rate will increase the risk that preference customers will pay a higher rate. SUB Brief, WP-02-B-SP-01, at 7; SUB Ex. Brief, WP-02-R-SP-01, at 8.

BPA's Position

BPA is currently taking public comment on whether BPA should increase the proposed settlement amount by 100 aMW. Doubleday *et al.*, WP-02-E-BPA-44, at 13-14. The decision as to whether to increase the settlement amount will be made in a forum separate from the current power rate case. *Id.* BPA proposed an appropriate method of allocating the costs of the proposed IOU settlements. *Id.* BPA stated that it was willing to consider increasing the IOU settlement amount from 1,800 to 1,900 aMW as long as BPA's goal not to increase the average PF rate over present levels could be met; it would not require BPA to reduce its TPP; it would not require a change in the DSI proposal; and there would be no impact on BPA's ability to meet its fish and wildlife commitments. Burns and Elizalde, WP-02-E-BPA-37, at 7. After BPA filed its rebuttal, BPA concluded a separate forum in which BPA proposed to increase the IOU settlement amount from 1,800 to 1,900 aMW. Subscription Supplemental ROD, at 11-23. REP settlement costs are equitably allocated between the PF Preference class and the RL class. *See* Doubleday *et al.*, WP-02-E-BPA-18, at 17-18; and Doubleday *et al.*, WP-02-E-BPA-44, at 13.

Evaluation of Positions

The PPC argues that BPA's other customers should not bear the cost of the extra 100 aMW of IOU benefits that BPA is currently considering. PPC Brief, WP-02-B-PP-01, at 67; PPC Ex. Brief, WP-02-R-PP-01, at 18-19. PPC argues that BPA should either lower the proposed allocation to the 1,800 aMW proposed in the Subscription Strategy, or purchase the additional 100 aMW of benefits at market rates and meld the cost into that of the 1,800 aMW so that the IOUs bear this additional cost. *Id.* SUB argues that the sale of the 100 aMW increases BPA's need to purchase power on the market to meet preference customer load growth, resulting in an increased likelihood of triggering a CRAC, which would result in a higher rate for preference customers. SUB Brief, WP-02-B-SP-01, at 7. In response to the suggestion that BPA should increase the proposed settlement amount from 1,800 to 1,900 aMW, BPA noted that BPA would consider adding the additional 100 aMW as long as BPA's goal of not increasing the average PF Preference rate over present levels could be met, no change in TPP is required, no change in the DSI rate proposal is required, and there is no impact on BPA's ability to meet its fish and wildlife commitments. Doubleday *et al.*, WP-02-E-BPA-44, at 13-14; *see* Burns and Elizalde, WP-02-E-BPA-08, at 12. These conditions provide significant protection to BPA's preference customers. BPA previously noted that it was taking public comment on whether BPA should increase the proposed settlement amount by 100 aMW. Doubleday *et al.*, WP-02-E-BPA-44, at 14. BPA noted that the decision as to whether to increase the settlement amount would be made in a separate forum. *Id.* In the Draft ROD, BPA concluded that to the extent that the increase could be achieved consistent with the above noted conditions, it would be appropriate to reflect 1,900 aMW, not 1,800 aMW, as the IOUs' proposed settlement benefits in order to ensure that BPA's rates are established in a manner that would recover BPA's costs. In other words, if BPA included only 1,800 aMW for ratemaking purposes, but actually provided 1,900 aMW, BPA would incur costs during the rate period that were not incorporated in BPA's rates.

PPC argues that BPA's assumption of 1,900 aMW as the amount for the IOU settlements is inconsistent with the practice of using current methodologies and assumptions in modeling rates. PPC Ex. Brief, WP-02-R-PP-01, at 18. In fact, however, BPA recently completed the public comment process noted above and released its Power Subscription Strategy Administrator's Supplemental ROD. In that document, BPA reviewed public comments on the issue of whether the IOU settlement amount should be 1,800 aMW or 1,900 aMW. After BPA's review of such comments, BPA determined that 1,900 aMW be proposed as the amount of the IOU Subscription settlement benefits. Subscription Supplemental ROD, at 11-23.

SUB argues that BPA erred in the Draft ROD because the additional 100 aMW above the 1,800 aMW identified for the IOU Subscription settlements must be met by augmentation, which increases the risk that BPA will underrecover its costs, causing the CRAC to trigger and increasing rates for BPA's preference customers. SUB Ex. Brief, WP-02-R-SP-01, at 8. BPA disagrees. Due to the high demand for BPA power, it is extremely unlikely that the additional 100 aMW would be met with augmentation purchases. It is likely that the additional 100 aMW would be met with monetary settlement payments. By reflecting these costs in BPA's rates, BPA will avoid underrecovery of costs or increasing the likelihood of CRAC triggering. SUB also argues that the Subscription Strategy ROD identifies 1,800 aMW as the cost-based benefit to the IOUs. *Id*. As noted previously, BPA's Subscription Strategy Administrator's Supplemental ROD decided the increase of IOU settlement benefits from 1,800 aMW to 1,900 aMW. SUB quotes a passage from the Subscription ROD to the effect that, at the time the Subscription Strategy was prepared, BPA had a limited inventory of power and BPA limited the amount of power sales to the IOU settlements. SUB argues that the Subscription Strategy would require BPA to have or acquire excess inventory to meet the provision of benefits above 1,800 aMW. *Id*. Again, however, it is BPA's expectation that the additional 100 aMW would likely not be met with augmentation purchases, but rather would be met with monetary settlement payments.

With regard to the suggestion that BPA should purchase power and meld the cost in with the cost of the 1,800 aMW, this would be inappropriate; BPA proposed an appropriate method of allocating the costs of the proposed IOU settlements. Doubleday *et al.*, WP-02-E-BPA-44, at 14. Simply because the amount is increased by 100 aMW does not mean that these costs should be treated differently. *Id.* As noted in BPA's direct testimony, REP settlement costs are equitably allocated between the PF Preference class and the RL class. *See* Doubleday *et al.*, WP-02-E-BPA-18, at 17-18. This is appropriate, because this allocation results in a rate level for the settlement sales that supports the proposed value of the settlement of the REP with regional IOUs. Doubleday *et al.*, WP-02-E-BPA-44, at 13. This allocation also helps to promote the wide and diversified use and distribution of Federal power. *Id.*

<u>Decision</u>

The decision as to whether to increase the IOUs' settlement amount has been made in a separate forum. That forum has now decided to propose 1,900 aMW as the total amount of IOU settlement benefits. BPA has concluded that this increase can be achieved consistent with the above-noted conditions. It is appropriate to reflect 1,900 aMW as the IOUs' proposed settlement benefits in order to ensure that BPA's rates are established in a manner that would recover BPA's costs. BPA uses an appropriate method of allocating the costs of the proposed IOU settlements.

<u>Issue 6</u>

Whether the rates for IOU Subscription settlements should reflect charges applicable to the PF Preference rate.

<u>Parties' Positions</u>

The PPC argues that the loads of preference customers are subject to charges and adjustments in addition to the PF rate, and that an equitable solution would be to eliminate such charges and adjustments from the PF rate or assess comparable charges to the RL rate. PPC Brief, WP-02-B-PP-01, at 65; PPC Ex. Brief, WP-02-R-PP-01, at 16.

<u>BPA's Position</u>

The RL and PF Exchange Subscription rates do not include the TAC or other similar charges, because all settlement sales must be concluded during the Subscription window and are provided in a prescribed amount and shape. Doubleday *et al.*, WP-02-E-BPA-44, at 13.

<u>Evaluation of Positions</u>

The PPC argues that BPA's Subscription Strategy stated that the IOU settlement power should be charged a "PF-equivalent" rate rather than the NR rate, and that this rate is inconsistent with BPA's proposal for preference customers and therefore is not a "PF-equivalent" rate. PPC Brief, WP-02-B-PP-01, at 65. PPC argues that this is so because the loads of preference customers are subject to charges and adjustments in addition to the PF rate, and that an equitable solution would be to eliminate such charges and adjustments from the PF rate or assess comparable charges to the RL rate. *Id.* First, proposed settlement sales to the IOUs are made under the RL and PF Exchange Subscription rates. Doubleday *et al.*, WP-02-E-BPA-44, at 13. BPA's Subscription Strategy did not state that the IOU settlement sales would be charged a "PF-equivalent" rate, but rather that BPA expected the rate to be "approximately equal" to the PF Preference rate, and the rate would be subject to establishment in a section 7(i) hearing. *See* Subscription Strategy at 16. BPA's statements in the Subscription Strategy and ROD were not final rate decisions, which can be made only in a section 7(i) hearing process. 16 U.S.C. §839e(i). BPA's discussions on rate issues in the Subscription process were limited to discussions of what might be included in BPA's initial proposal and then might be subject to change in the formal hearing.

Furthermore, BPA's general statement that IOU settlement sales will be at a rate "approximately equal to the PF Preference rate" (subject to the above-noted conditions) does not require the application of the noted charges to the RL rate. The Subscription Strategy spoke in general terms about the level of the RL and PF Preference rates. The Subscription Strategy did state, however, that rates for sales to public agency customers made after the Subscription window closes would be subject to a "targeted adjustment charge." *See* Subscription Strategy, at 15. The Subscription Strategy did not state that such a charge would apply to the RL or PF Exchange Subscription rates. Further, the Subscription Strategy did not say that the RL rate would be eligible for all of the same rate adjustment features of the PF Preference rate. Indeed, this is consistent with the fact that the RL rate is not subject to a number of charges that apply to the PF Preference rate, such as the TAC, TACUL, SUMY, and other charges. This is because such settlement sales must be established during the Subscription window and are for a fixed amount and shape of power during the rate period. Doubleday *et al.*, WP-02-E-BPA-44, at 13. For example, the RL and PF Exchange Subscription rates do not include the TAC because all IOU settlement sales must be concluded during the Subscription window. *Id.* Other charges to the PF Preference rate are not applicable to the settlement sales for similar reasons. *Id.*

PPC argues that it does not find any distinction between its characterization of the RL rate as "PF-equivalent" and BPA's characterization of the RL rate as "approximately equal to the PF rate." PPC Ex. Brief, WP-02-R-PP-01, at 16. This distinction is discussed in greater detail above. One of BPA's primary points, however, is that the Subscription Strategy did not provide that the RL and PF rates would be *equivalent*, as suggested by PPC, because there are differences in the products available under the rates and such differences do not support the application of certain charges and adjustments to the RL rate. PPC also argues that, in effect, RL customers are given preference to BPA's lowest cost-based rates in a manner that is superior to that proposed for preference customers. BPA disagrees. BPA's power sales to IOUs at the RL rate are for 24-hour flat-block power only. Furthermore, while purchasers of power at the RL rate are not subject to charges that do not apply because of the type of power provided, BPA's preference customers have access to the full panoply of products available at the PF Preference rate. BPA's application of the RL rate to the IOU settlements is not superior to preference customers' purchases of a variety of products at the PF Preference rate. Furthermore, it is worth noting that if a preference customer were to purchase the product being offered to the IOUs under the proposed settlements, it would pay exactly the same rate for such power.

Decision

The issue of whether BPA should eliminate charges and adjustments from the PF Preference rate is addressed in ROD chapter 11. The rates for IOU Subscription settlement sales are not subject to the charges and adjustments that apply to PF Preference rate sales; such charges and adjustments are not used in the calculation of the RL and PF Exchange Subscription rates.

Issue 7

Whether the duration of the proposed IOU Subscription settlement agreements is reasonable compared to the duration of the proposed RPSAs.

Parties' Positions

PPC argues that the proposed IOU Subscription settlements are enriched by the duration of their offered term. PPC Brief, WP-02-B-PP-01, at 67; PPC Ex. Brief, WP-02-R-PP-01, at 19.

BPA's Position

The establishment of the terms of the IOU Subscription settlements and the RPSAs is a contract negotiation matter that will not be resolved in the rate case. BPA's prototype RPSAs and IOU settlement agreements permit terms up to ten years. The IOU settlements are not enriched by the duration of their term.

Evaluation of Positions

The PPC argues that the proposed IOU Subscription settlements are enriched by the duration of their offered term. PPC Brief, WP-02-B-PP-01, at 67. The PPC argues that IOUs may select up to ten years of benefits through this settlement, a term potentially longer than a contract for participation in the REP. *Id.* PPC cites no basis upon which it concludes that the duration of the proposed settlements would differ from the duration of the proposed RPSAs. Furthermore, BPA has not yet completed negotiations, or offered or executed any of the proposed IOU Subscription settlements or RPSAs. Indeed, the terms of the proposed settlements and RPSAs are not being established in the current proceeding. This proceeding is only for the establishment of rates that apply to BPA's power sales for the next five-year rate period, beginning in FY 2002, and not the contract provisions that implement such sales. In any event, however, BPA has issued a letter requesting comments on its prototype RPSAs and IOU settlement agreements. The prototype RPSA is offered for a term up to ten years. The prototype IOU settlements are available for either a five year or a ten year term. While these terms are not yet final, BPA's prototype RPSA and IOU settlement agreements provide the same potential ten year duration for both types of contracts. This does not enrich the IOU settlements over the RPSAs.

PPC argues that in light of recent Congressional efforts to phase out the REP (citing H.R. Rep. No. 293, 104th Cong., 1st Sess. 92 (1995)), its argument that benefits under the IOU settlements are enriched by the duration of the offered term (ten years) is not speculative. PPC Ex. Brief, WP-02-R-PP-01, at 19. PPC argues that any settlement that provides benefits beyond the

FY 2002-2006 rate period unduly enriches the settlement, because there is no evidence that benefits under the traditional REP would extend past 2006. *Id*. First, the authority cited by PPC is comprised of comments in a House report, not an actual change in legislation. While the comments were made five years ago, the REP is still in existence. In addition, the previous Residential Exchange agreements were in effect for 20-year terms. BPA's proposed RPSAs, which will implement the REP in the next contract period, are for up to a 10-year term. While it is possible that the REP could be terminated by new legislation, such legislation is still speculative. Similarly, the contracts could address the termination of the contract in the event of such legislation. In summary, BPA believes that a ten year term for the IOU settlements is appropriate for rate development purposes.

Decision

While BPA has not yet offered or executed any of the proposed IOU Subscription settlements or RPSAs, and the terms of such contracts are not established in this rate proceeding, BPA has released prototypes for public comment that provide the same duration for both contracts. Thus, the proposed settlements are not enriched by a potentially longer term.

15.0 DIRECT SERVICE INDUSTRY POWER RATE DEVELOPMENT

15.1 Introduction

The rates charged to BPA's DSI customers are based on section 7(c) of Northwest Power Act. 16 U.S.C. §839e(c). 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." 16 U.S.C. §839e(c)(1)(B). There are three specific directives associated with this provision:

1. Pursuant to section 7(c)(2), this determination is 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.

2. Section 7(c)(2) also establishes the so-called DSI "floor rate," which requires that the DSI rates shall be no less than the rates in effect for the contract year ending June 30, 1985.

3. 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 chapter of the ROD addresses issues relating to these statutory provisions and issues that have been raised in connection with the Compromise Approach for service to the DSIs that was proposed in this proceeding.

15.2 7(c)(2) Industrial Margin

15.2.1 Revenue Taxes

BPA has performed a margin study on only two prior occasions. The margin was first calculated during the 1985 rate case. Then, in 1987, BPA established the IP-PF rate link, under which the typical margin was inflated each rate period by the Gross National Product deflator. The rate link made it unnecessary to recalculate the typical margin until 1996. 1985 ROD, WP-85-A-BPA-02, at 129-158; 1996 ROD, WP-96-A-02, at 145-189. Since the IP-PF Link has expired, BPA has once again conducted an industrial margin study and calculated new values for the typical margin for the FY 2002-2006 rate period.

As noted above, section 7(c)(1)(B) of the Northwest Power Act provides that rates for sales to DSIs must be "equitable in relation to the retail rates charged by . . . the public body and cooperative customers to their industrial consumers in the region." In order to accomplish this goal, section 7(c)(2) of the Northwest Power Act further provides that:

> The determination under paragraph (1)(B) of this subsection shall be based upon 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 but shall take into account:

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

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

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

16 U.S.C. §839e(c)(2). Thus, the wholesale rate that forms the basis for the DSI rate must include a typical retail margin that takes into account the factors stated above. The purpose of the 7(c)(2) Industrial Margin Study is to calculate that margin.

PPC assisted in gathering the information used in the industrial margin study. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 118. The reason for this was that BPA was informed that the participating utilities believe public distribution of customer-specific information could cause them competitive harm. Ebberts, WP-02-E-BPA-22, at 2-3. As a condition for providing this data, the PPC required that all references identifying the utility and its industrial customer(s) be deleted from all data sources. *Id*. Thus, utility and industry identities were masked, much as was done in the 1985 margin study. *Id.* Entities wishing to review the data, including BPA, were required to sign a confidentiality agreement that limits its use and dissemination. *Id.*

Eligibility for participation in the survey was limited to utilities that have at least one industrial customer with a peak demand of at least 3.5 MW. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 117. BPA identified 35 public body and cooperative customers believed to be serving at least one industrial customer with a peak demand of at least 3.5 MW, and received 22 responses. Ebberts, WP-02-E-BPA-05, at 3-4. BPA requested that utilities provide the most recent cost of service analyses used in establishing existing industrial rates. Also requested was information from contracts for industrial service under arrangements other than traditional tariff service (*e.g.*, market based or market access pricing). *Id.* at 4.

This information was used to allocate costs in categories that were then either included or excluded from the margin. *Id.* at 5-6. Costs included in the typical margin were "those direct and indirect overhead costs that are not associated with the production, transmission, and distribution of electricity." *Id.* at 7. The individual margins derived from this information were then weighted according to the amount of energy sold by individual utilities. The result was a typical industrial margin of 0.42 mills/kWh. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 119.

Issue

Whether BPA erred in excluding revenue taxes from the margin calculation based on the conclusion that revenue taxes are not typical.

Parties' Positions

The IOUs have raised numerous issues in support of their contention that BPA has arbitrarily excluded revenue taxes from the industrial margin. They claim that BPA correctly included utility taxes in the margin in the 1985 rate case and should adopt that practice in this case. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 29. In conjunction with their position that BPA should rely on their interpretation of the 1985 ROD, the IOUs argue that BPA's witness did not make any independent analysis regarding the issue of "whether government-owned utilities and cooperatives typically pay taxes based on gross receipts from the sale of electric power and whether such taxes should be included in the 'typical retail margin'." *Id.* at 28; *see also* PGE Brief, WP-02-B-GE-01, at 9.

The IOUs also maintain that BPA has imposed an improper test for determining whether revenue taxes are includable in the margin. *Id.* at 34. According to the IOUs, BPA's test improperly equates the word "typical" with "majority" in applying that term to the determination of what cost items are properly included in the industrial margin. *Id.* at 35. PPC also dislikes BPA's test and argues that the typicality of revenue taxes should be based on the sample eligible to participate in the margin study, not the total number of BPA customers serving industrial load. PPC Brief, WP-02-B-PP-01, at 57.

The IOUs insist further that the alleged error was compounded by BPA's reliance on the faulty premise that only the state of Washington imposes a revenue tax. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 36. In support of this argument, the IOUs cite a number of statutory provisions which are purported to prove that BPA's utility customers in Oregon and Idaho "do pay revenue taxes or other payments in lieu of taxes to governmental authorities." *Id.* at 38. Thus, even under BPA's "majority" test, the IOUs conclude that revenue taxes are typical. *Id.*

PPC makes a similar argument, asserting that perhaps as many as 29 utilities in Oregon pay franchise fees and in-lieu taxes, and claiming that BPA should have investigated the issue further based on IOU testimony that "a few telephone calls" had shown that Oregon jurisdictions charge revenue taxes. PPC Brief, WP-02-B-PP-01, at 58-59, citing Hoff *et al*., WP-02-E-AC/GE/IP/MP/PL/PS-03, at 19.

The IOUs also state that substituting the cost of DSI delivery facilities for distribution costs understates distribution costs allocable to the margin to the extent that property and other taxes are functionalized by the utility to distribution. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-03, at 39. The IOUs also argue that market conditions have changed since the 1996 rate proceeding, and so BPA does not need to "artificially" push the DSI rate as low as possible to retain industrial load in a competitive market. *Id.* at 40. Similarly, PPC argues that "the only time that revenue taxes have been excluded from BPA's margin study was in an atypical year, 1996, when BPA was struggling to keep its DSI rates competitive and retain load." PPC Brief, WP-02-B-PP-01, at 56. PPC therefore concludes that "revenue taxes may be considered typical under normal circumstances." *Id.* Finally, the IOUs argue that BPA has ignored the intent of Congress and denied benefits to participants of the Residential Exchange by failing to add a sufficient industrial margin to the DSI rate. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-03, at 41; *see also* PGE Brief, WP-02-B-GE-01, at 10.

Arguments made by the DSIs and Alcoa/Vanalco support excluding revenue taxes from the margin. The DSIs argue that revenue taxes are neither “typical” nor “margin.” DSI Brief, WP-02-B-DS-01, at 25. The DSIs interpret the 1985 ROD as determining that “there is a clear relationship between margin per kilowatthour and customer size.” *Id.* at 27. Thus, using a 3.5 peak MW threshold as the minimum sized load to include in the data sample is appropriate for most cost categories (*e.g.*, meter reading, billing and collections, and customer service) because it is consistent with the section 7(c)(2) requirement that the Administrator take into account the “size and character” of the loads. *Id.* However, because revenue taxes are not size related, the DSIs argue that it was appropriate to consider all BPA customers serving industrial load of any size for that cost category. The DSIs argue, as well, that the IOUs failed to introduce credible evidence into the evidentiary record to establish their claim that states other than Washington levy revenue taxes. *Id.* at 29.

In addition to arguing that revenue taxes are not typical, the DSIs argue that revenue taxes are not margin. *Id.* at 30. Obligations for remittance of taxes imposed on a utility by the taxing authority are far different, the DSIs claim, from normal costs. In such instances, the utility is simply acting as a conduit for the taxing authority’s policy choices with respect to who is taxed and how the tax is to be collected. *Id.* at 29. This fact, it is argued, “creates the anomalous result that the form of tax determines whether it is margin or not.” *Id.* Thus, to the extent that it can be concluded that revenue taxes are “typical,” they should be allocated to the four cost categories based upon the ratio of total costs assigned to each category. *Id.*

Alcoa/Vanalco make a similar argument, maintaining that Washington’s revenue tax is “collected as a fixed percentage on the total delivered cost of power.” Alcoa/Vanalco Brief, WP-02-B-Al/VN-01, at 69. Since it is not assessed uniformly across all loads, they argue that the tax should not be considered part of the typical margin. *Id.* Alcoa/Vanalco also assert that the 1.72 mills/kWh margin proposed by PPC, based on revenues actually needed to accomplish billing and customer service functions, is irrational on its face and should be replaced by a 0.34 mills/kWh margin. *Id.* at 8.

The IOUs take exception to the Administrator’s draft decisions in the Draft ROD. They disagree with the Administrator’s draft decision “regarding the Distribution component attributable to margin.” IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 31 and n. 98. They also argue once again that BPA’s treatment of revenue taxes deprives the Residential Exchange participants of benefits totaling $8,000,000 per year over the rate period due to BPA’s failure “to acknowledge the interrelationship between the floor rate calculation and margin calculation.” *Id*. at 32. The IOUs further maintain that they have provided the only testimony on this issue. *Id*. at n. 102. The IOUs argue further that BPA has taken too narrow a view of “revenue taxes” and has not conducted a proper analysis of the issue. *Id*. at 32. Another argument repeated in the IOU brief on exceptions is that Congress intended the margin to be 25 percent to 33 percent. *Id*. at n. 105.

In its brief on exceptions, PPC re-argues the contention that the determination regarding revenue taxes should have been based on the margin sample and not the entire population of utilities serving industrial load. PPC Ex. Brief, WP-02-R-PP-01, at 13. PPC also states that in the Draft ROD, BPA did not accurately reflect PPC's position when BPA assumed that PPC considered revenue taxes to be overhead costs. *Id*.

<u>BPA's Position</u>

Revenue taxes are not typical and should therefore be excluded from consideration in calculating the industrial margin. Ebberts, WP-02-E-BPA-22, at 8. Washington is the only state in BPA's service territory that can reasonably be characterized as assessing a revenue tax. *Id.* at 8; Ebberts, WP-02-E-BPA-47, at 6. Thus, such taxes are not typical with respect to the PNW region that BPA serves, and they are not typical with respect to the relevant BPA customer base serving industrial load within that region. Ebberts, WP-02-E-BPA-22, at 8; and Ebberts, WP-02-E-BPA-47, at 6.

<u>Evaluation of Positions</u>

BPA's analysis of whether revenue taxes should be included in the margin considered both: (1) the number of utilities serving industrial load and subject to a revenue tax; and (2) the number of states within BPA's service territory which levy a revenue tax. Ebberts, WP-02-E-BPA-47, at 6. Based on those parameters, BPA concluded that, for purposes of calculating the industrial margin, only the state of Washington levies a gross revenue tax. *Id*. This means that revenue taxes are typical neither of the states within BPA's service territory nor among BPA's customers serving industrial load. *Id*. Therefore, revenue taxes are not "typical" as contemplated by section 7(c)(2) of the Northwest Power Act and should be excluded from the margin. *Id*.

The IOUs and PPC have challenged this finding and presented numerous arguments attempting to show that revenue taxes are, in fact, typical. PPC concludes that they should be assigned to the "Other" category, with the result that they would be included, in their entirety, in the margin. PPC Brief, WP-02-B-PP-01, at 60. In the Draft ROD, BPA inferred that PPC intended that revenue taxes be treated as direct or indirect overhead, which would achieve that result. BPA felt that this step was necessary to complete PPC's argument, because once an item is considered typical for purposes of the margin calculation, a determination must be made regarding how that item should be allocated across the various categories. PPC's brief on exceptions, however, takes issue with BPA's characterization of that aspect of its position. PPC Ex. Brief, WP-02-R-PP-01, at 14. Consequently, BPA defers to PPC's desire not to adopt such a position.

The IOUs argue that the two-part test employed by BPA, as described above, is improper because it is a new standard, uniquely applied to revenue taxes in contradiction of the methodology used in 1985. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-03, at 34. While BPA is not bound by the 1985 ROD, its actions in this instance are not in any way inconsistent with the principles guiding the Administrator in that case. There, the DSIs had argued, in part, that "revenue taxes should be excluded because they are not paid in all jurisdictions." WP-85-A-BPA-02, at 137. The Administrator found this argument unpersuasive: "The fact that not all utilities incur revenue taxes is no more a basis for a blanket exclusion from the margin than would be the exclusion of any other cost not incurred by each and every public agency in the region." *Id.* at 138. The Administrator's finding in 1985, then, responded to the very two criteria that BPA has adopted in this case: the number of jurisdictions levying revenue taxes and the number of public agency customers subject to such taxes.

The Administrator concluded in 1985 only that the "record fails to provide a compelling reason for not considering revenue taxes as a cost of doing business." *Id.* at 139. Thus, the potential for reconsideration based on different arguments, or a more complete record, was clearly a possibility. In 1996, the Administrator found that a more complete record had been developed, one that focused on which states levied revenue taxes and which of those states had public agency customers serving industrial load. 1996 ROD, WP-96-A-02, at 178. Based in part on this rationale, revenue taxes were excluded from the margin calculation. Thus, the issue of whether revenue taxes should be included in the industrial margin was addressed in both 1985 and 1996, the only two occasions when a margin calculation was necessary. 1985 ROD, at 129-158; 1996 ROD, at 145-189.

BPA's witness reviewed materials from both the 1985 and 1996 rate cases. Tr. 1734, 1835. This review was prompted by the witness's belief that, in preparing his testimony, "[i]t was important to know the whole history of the typical margin." Tr. 1835. As a result of this review, the witness determined that it was appropriate to rely upon the methodology more closely represented by 1996. Tr. 1747, 1835. This conclusion was based on the witness's professional assessment that the 1996 methodology "is a correct way to do it." Tr. 1750. The methodology, then, is not entirely new. It is simply a refinement of principles that have been used in this arena on the only two prior occasions when a typical industrial margin has been calculated.

To the extent that any features of this methodology apply uniquely to revenue taxes, that treatment is appropriate given the difference between taxes and most of the other cost items taken into account in calculating the margin. For example, the margin sample itself is limited to utilities that serve a peak industrial load of 3.5 MW or greater. In keeping with the statutory requirement to consider the "comparative size and character of the loads served," the 3.5 MW limitation attempts to account for any economies of scale realized in the retail rates of larger industrial loads with respect to routinely incurred costs reported in the sample. Taxes, by contrast, are not costs incurred by a utility, but costs imposed by governmental bodies making policy choices. The Joint DSIs make this point in testimony describing the Washington revenue tax:

> Revenue taxes are not a cost of doing business, rather a consequence of a utility doing business in Washington. The State of Washington has chosen to collect its taxes in a number of ways, a primary source being retail sales taxes. Rather than charge the sales tax on electricity, the state imposes a revenue tax on the utilities. The utilities are collecting these taxes through their billings, but the money collected does not truly belong to the utility. The utility has no real discretion in determining how these funds will be used. They must remit all collections to the state. Therefore, just as sales taxes are not part of a retail seller's margin, revenue taxes are not a part of a utility's margin.

Schoenbeck *et al.*, WP-02-E-DS/AL/VN-06, at 7. While the Joint DSIs are arguing that revenue taxes are not margin, the description also bears on why taxes should be treated differently than routine costs associated with the business of electric utilities. Because taxes are imposed by taxing authorities for policy reasons, there is no basis to initially assume any economic relationship between taxes imposed and the size of the load. Therefore, the basis for a 3.5 MW threshold is not necessarily applicable. Moreover, the limitations of the margin sample with respect to the revenue tax issue are compounded by the fact that participation is voluntary. As the DSIs correctly note: ". . . by making the typicality determination based on the whole population, as BPA did both in 1996 and in this case, BPA eliminated the concern that the self-selection process could bias the results on this issue." DSI Brief, WP-02-B-DS-01, at 28. Self-selection is a greater concern for this issue because of the lack of uniformity across jurisdictions on taxation, a problem not present for routine costs that are unaffected by political boundaries.

Thus, there are sound reasons for treating revenue taxes independently from the margin sample, and the Administrator is not persuaded by PPC's reiteration of its position in its brief on exceptions. PPC Ex. Brief, WP-02-R-PP-01, at 13. Moreover, the test used by BPA appropriately focuses on factors emphasized in the two previous margin determinations, *i.e.*, the number of jurisdictions that impose revenue taxes and the number of preference customers who are subject to such taxes.

In addition to arguing that BPA's methodology is flawed, the IOUs assert that BPA's application of its own methodology is equally flawed and therefore achieves an incorrect result. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 34. The argument is twofold: (1) BPA has improperly defined "typical" to mean "majority"; and (2) BPA has erroneously concluded that Washington is the only state that imposes revenue taxes. Neither argument has merit.

With respect to the first issue, BPA's witness did not specifically define "typical" to mean "majority" as suggested by the IOUs. Instead, he concluded that: (1) only Washington imposes a revenue tax; and (2) most of BPA's public agency customers with industrial load are located outside of Washington. Ebberts, WP-02-E-BPA-22, at 8; Ebberts, WP-02-E-BPA-47, at 6. BPA's witness testified that he defined "typical" as meaning "serving as a characteristic example" or being "representative of a whole group." Tr. 1869, 1870. He also indicated they he did not believe that "a very small minority would represent typical" and stated that, in this instance, he did apply a "majority rule" in the case of revenue taxes. *Id.*

This approach, in general, is consistent with the approach taken in 1996:

> If a given trait is peculiar only to a minority of a population, it cannot be said to be either 'representative of the whole group' or 'a characteristic example.' If anything the opposite is the case: the absence of the trait is representative and characteristic. Therefore, if only a minority of utilities include revenue taxes in their margins, then such taxes are not a component of the typical industrial margin.

1996 ROD, WP-96-A-02, at 178.

While not required to do so, BPA finds this approach reasonable and has adopted it in this case. Applying this standard, revenue taxes should certainly be excluded from the margin calculation if only a minority of the states in BPA's service territory impose revenue taxes and only a minority of BPA customers pay revenue taxes. It is not necessary to determine whether a bare majority would be sufficient to make a cost typical.

PPC and the IOUs also argue that, even applying such a rule, BPA's determination is incorrect because, they claim, the States of Oregon and Idaho impose gross revenue taxes, and many local government units in Oregon require electric utilities to pay franchise fees. However, while some of the referenced taxes are based on revenues, it is not proper to characterize them as revenue taxes. BPA has made it clear in 1985, 1996, and again now that the state of Washington imposes a revenue tax. The relevant statutory provision is Chapter 82.16 of the Revised Code of Washington, which describes the "Public Utility Tax" and provides as follows:

> There is levied and there shall be collected from every person a tax for the act or privilege of engaging within this state in any one or more of the businesses herein mentioned. The tax shall be equal to the gross income of the business, multiplied by the rate set out after the business, as follows:
>
> (1) Railroad, express, railroad car, water distribution, light and power, telephone and telegraph businesses: Three and six-tenths percent;

R.C.W. 82.16.020.

The statute defines "light and power business" as the "business of operating a plant or system for the generation, production or distribution of electrical energy for hire or sale." R.C.W. 82.16.010(5). "Gross income" is defined as the "value proceeding or accruing from the performance of the particular public service or transportation business involved, including operations incidental thereto, but without any deduction on account of the cost of the commodity furnished or sold, the cost of materials used, labor costs, interest, discount, delivery costs, taxes, or any other expense whatsoever paid or accrued and without any deduction on account of losses." R.C.W. 82.16.010(13).

The definition of "gross income" has been held to include state and city privilege taxes collected by a PUD supplier of electricity, even though customers of a district were billed for privilege taxes as a separate item and the receipts were remitted separately and directly to the taxing authority. *Public Utility Dist. No. 3 of Mason County v. State*, 427 P.2d 713 (1967). It has also been held that the Washington tax is not a license tax serving as a prerequisite to entering into business or promoting a regulatory purpose; rather, it is imposed solely for revenue purposes. *Columbia River Bridge Co. v. State*, 282 P.2d 283 (1955). Similarly, a tax imposed by ordinance of the City of Seattle was determined to be a license or occupation tax and not a tax imposed on the sale or distribution of property or a service. *Seattle Gas Co. v. City of Seattle*, 73 P.2d 1312 (1937).

The essential features of the Washington revenue tax, then, can be described as follows: (1) it is a comprehensive tax, imposed solely for revenue purposes; (2) it is levied and administered at the state jurisdictional level; (3) it is a tax on "gross income," defined broadly; and (4) it is not a license fee, regulatory tax, or occupation tax.

The question then becomes whether such taxes are, for purposes of calculating the industrial margin, typical of the BPA service territory and typical of the Administrator's customer base serving industrial load. The answer is no. For example, the IOUs offer ORS §308.805 and §308.807 as an example of a revenue tax paid by cooperative utilities in the State of Oregon. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 37. The statute provides as follows:

> (1) Every association of persons, wholly mutual or cooperative in character, whether incorporated or unincorporated, the principal business of which is the construction, maintenance and operation of an electric transmission and distribution system for the benefit of the members of such association without intent to product profit in money and which has no other principal business or purpose shall, in lieu of all other taxes on the transmission and distribution lines, pay a tax on all gross revenue derived from the use or operation of transmission and distribution lines (exclusive of revenues from the leasing of lines to governmental agencies) at the rates prescribed by ORS 308.807. The tax shall not apply to or be in lieu of ad valorem taxation on any property, real or personal, which is not part of the transmission and distribution lines of such association.

ORS §308.807(1).

The taxed entity may elect to base the amount of tax owing to the lesser of 4 percent of gross revenue from "use or operation of transmission and distribution lines minus the cost of power" or an alternative formula based on the "market value" of the transmission and distribution lines. ORS §308.807(2). The taxes are distributed to the relevant county governments and apportioned to the county school fund and general fund. ORS §308.815.

The Oregon tax is not analogous to the Washington revenue tax in any fundamental or meaningful way. First, it is not a revenue tax at all, but rather a property tax. As the Supreme Court of Oregon has held:

> ORS chapter 308 deals with valuation of various types of property for property tax purposes. ORS 308.805 through 308.820 deal with a specific type of property (electrical distribution systems) owned by a specific class of taxpayers (non-profit electric cooperatives). ORS 308.805 provides a method of taxing such property different from the usual ad valorem method based on assessed value. Although the tax is measured by gross revenue, the tax is more properly considered a property tax than an income tax.

Lane Electric Cooperative v. Department of Revenue, 765 P.2d 1237, 1239 (1988).

While the holding of the Oregon Supreme Court is not binding on the Administrator for purposes of interpreting section 7(c)(2), the description clearly comports with the statutory language, and the Administrator finds it persuasive with regard to the character of the tax. Moreover, the court's interpretation is supported by the fact that the income basis for the tax applies only if the tax owed is less than the tax would be if based on the market value of the property itself. Thus, the tax embodied in ORS chapter 308 is not a revenue tax, but a property tax.

Moreover, the Oregon tax differs in other material respects from the tax imposed by the state of Washington. First, it is not a comprehensive tax at the state level; instead, it is specifically targeted at a very limited classification of taxpayers and is earmarked for use by the county for specific purposes. Second, because the funds are distributed to the county governments, the tax is not wholly administered at the state level. Third, even if it could be characterized as an income tax, the Oregon tax is not a tax on "gross income," but a tax on income derived from a specific and limited type of property. For purposes of calculating the margin, two taxes of a completely different character cannot simply be lumped together and treated as though they are the same thing.

The IOUs' reliance on Idaho's statute, IC 63-3502, is similarly misplaced. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 38. That tax applies to any "Cooperative Electrical Association," defined as "any nonprofit, cooperative association organized and maintained by its members, whether incorporated or unincorporated, for the purpose of transmitting, distributing or delivering electric power to its members." IC 63-3501. The tax is computed at a rate of 3.5 percent on gross earnings after deducting that figure by its costs of power and certain Energy Northwest costs. IC 63-35-02. Moreover, payment of the tax is deemed to be inlieu of all other property taxes. Thus, it is very similar to the Oregon tax and for the same reasons, it is a property tax rather than a revenue tax. As the DSIs correctly note:

> Many of the utilities that assess taxes that might be called 'revenue taxes' in reality collect taxes *in lieu* of property taxes. Property taxes are appropriately assigned to the production, transmission, and distribution categories in the margin study, depending upon the taxable property upon which they are levied. These *in lieu* taxes are not revenue taxes of the kind that is levied by utilities located in the State of Washington.

DSI Brief, WP-02-B-DS-01, at 30.

Therefore, it is incorrect for PPC and the IOUs to conclude that these tax statutes should be characterized as revenue taxes.

The IOUs also cite franchise fees authorized under ORS §221.420 and §225.270. Again, such taxes are not revenue taxes. ORS §221.420 is a statute that, primarily, broadly sets forth the regulatory authority of municipalities with respect to public utilities, including ratesetting authority and the authority to order construction and modification of physical equipment. One part of this statute permits the imposition of fees and establishment of terms and conditions whereby a utility "may be permitted to occupy the streets, highways or other public property within such city." Thus, the statute does not authorize the municipalities to charge a revenue tax.

The statute gives municipalities the authority to regulate the conduct of utility business within the municipal limits and to charge an "occupation fee" that may be based on gross revenues. As indicated above, the Washington courts have held that the Washington revenue tax is not a tax of this type. And for good reason: such taxes are not comprehensive, they are administered locally, and they are basically "occupation" taxes that serve regulatory purposes. The IOUs' reasoning with respect to franchise fees levied pursuant to IC 50-329 and 50-329 is flawed for essentially the same reasons. Thus, they are not analogous to the tax levied by the State of Washington in any material respect and they cannot accurately be characterized as revenue taxes.

As for ORS §225.270, that statute authorizes municipally owned utilities to assess 3 percent of annual gross operating revenue derived from electric powerplants or systems or distribution systems "for the purpose of reducing general property taxes within such city." Again, simply because the tax is based on a percentage of revenues, it does not necessarily follow that the tax is a revenue tax. In this instance, the legislature made a policy choice to require that certain revenues be used to benefit a particular class of taxpayers, *i.e.*, those who pay property taxes within the city limits. Such a tax scheme is not comprehensive, nor is it imposed for revenue purposes.

In conclusion, the legal analysis shows that BPA's witness was correct in stating that only the state of Washington levies a revenue tax for purposes of considering whether such taxes are includable in the industrial margin. Ebberts, WP-02-E-BPA, at 8; Ebberts, WP-02-E-BPA-47, at 6. Parties such as the IOUs and PPC have complained repeatedly that no independent judgment was exercised and, as a result, there is no factual basis for such a conclusion. *See, e.g.,* IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 28. Such contentions are without merit. BPA's witness exercised independent judgment in determining what test should be used to determine whether revenue taxes should be included in the margin. As the BPA witness repeatedly testified, he did not use the 1996 ROD as precedent. To the extent he relied on the 1996 ROD, it was because, in his independent professional judgment, it provided the correct guidance. Tr. 1750.

With respect to the factual basis for the conclusion reached, BPA has consistently maintained that no factual evidence is required to reach the conclusion that only Washington levies revenue taxes. The answer to that question, as illustrated above, can be derived independently through the exercise of reasoning applied to nothing other than authorities commonly used in legal analysis. It would have been inappropriate under the procedural rules to make such materials a part of the factual record, or to require the witness to testify to legal issues. *See Rules of Practice to Govern These Proceedings*, WP-02-O-01, at 5.

The IOUs contend that BPA takes a view of revenue taxes that is too narrow, arguing that the Draft ROD "concludes that only Washington levies revenue taxes because a tax is a revenue tax only if it is just like the taxes levied in Washington." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 32. Such a statement ignores the analysis and conclusions from the Draft ROD. The Administrator concluded in 1985, 1996, and again here that Washington levies a revenue tax. The simple fact is that the other taxes proposed by the IOUs for inclusion in the margin are not revenue taxes. As is abundantly clear from the discussion above, this conclusion was derived at three levels: primary statutory interpretation, examination of relevant case law, and comparison with the Washington statute. All three levels of analysis lead to the same conclusion. Nowhere does BPA state that a tax has to be "just like" the Washington tax in order to be a revenue tax, but it does have to be a revenue tax.

Because BPA's conclusion regarding which jurisdictions levy revenue taxes is correct, it follows that the only factual determination necessary is whether, at a minimum, a majority of the Administrator's public agency customers serving industrial load are subject to Washington's revenue tax. BPA's witness provided this information in direct testimony and furnished updated numbers in rebuttal, concluding that 32 utilities serving industrial load are in Washington, and 51 are located elsewhere. Ebberts, WP-02-E-BPA-22, at 8; Ebberts, WP-02-E-BPA-47, at 7.

The evidence provided by BPA was not refuted by any party. While making numerous arguments regarding the proper application of the statutory directives and such matters as whether to use the margin sample or the general population, no one supplemented the factual record or offered any convincing rebuttal to BPA's evidence. PPC was content to rely upon "BPA's direct case and historical evidence in [its] testimony." Hansen *et al.*, WP-02-E-PP-06, at 25. The IOUs argued about the meaning of "equitable" and asserted only that "[w]ith a few telephone calls, we identified several jurisdictions in Oregon that levy revenue taxes on public utilities and cooperatives." Hoff *et al.*, WP-02-E-AC/GE/IP/MP/PL/PS-03, at 19. In rebuttal, BPA's witness noted that such unsubstantiated anecdotal evidence was not a sufficient basis for reaching the conclusion that jurisdictions other than Washington levy revenue taxes. Ebberts, WP-02-E-BPA-47, at 6. On brief, PPC makes the following observation with respect to the IOU testimony:

> The parties' evidence may have been insufficient to establish a foundation for a margin study or to conclude that a majority of regional utilities, as the witness defined "typical", with any industrial customers are charged revenue taxes. However, it is without question sufficient information to warrant further investigation by BPA into the existence of revenue taxes outside of Washington. No such investigation occurred.

PPC Brief, WP-02-B-PP-01, at 59.

Notably, no support is cited for the conclusion that BPA is under an obligation to conduct such an investigation. Indeed, it would be hard to imagine how a rate proceeding could ever end if, when confronted by evidence "insufficient" to support a party's conclusion, BPA were under an affirmative duty to conduct an "investigation" to ascertain whether other "sufficient" evidence, not presented by the party, can be found. PPC's logic is untenable. The uncontradicted evidence on the record is sufficient to reach the conclusion that revenue taxes are not typical for the purpose of calculating the industrial margin.

The IOUs also argue that BPA's margin calculation is not in keeping with actual margin levels or the intent of Congress. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 41. With respect to the first point, the IOUs rely on a document for which they requested official notice. That request has been denied. *See* ROD chapter 18. Thus, there is no evidence on the record to support the IOUs' contention. Moreover, BPA does not believe that such information would be particularly relevant or helpful to determining the acceptable range for the section 7(c)(2) industrial margin calculation. As BPA's witness noted: ". . . [T]he typical industrial margin is not the same thing as what you may find to be a margin in retail rate making. This thing that I am doing is an artifact of the Act; no other utilities do this. . . ." Tr. 2009.

As to the intent of Congress when it enacted this provision, the IOU position is equally unpersuasive. The IOUs make no attempt to show any relationship between the industrial margin and the cited exhibit, which is described as showing a "prototypical rate case with typical margins of 25 and 33 percent of the applicable wholesale power costs." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 43. As noted in BPA's testimony, cited above, and as is clear from the statutory language, the typical industrial margin was a creation of the Act itself. It was not to be equated with actual margins. This is made plain by the statutory language that refers to "typical margins" and then requires the Administrator to take into account:

> (A) the comparative size and character of the loads served;
> (B) the relative costs of electric capacity, energy transmission, and related delivery facilities provided and other service provisions; and
> (C) direct and indirect overhead costs, all as related to the delivery of power to industrial customers . . . .

16 U.S.C. §839e(c)(2). The statute creates a ratemaking directive that must be interpreted and applied in a manner that comports with all of BPA's ratemaking requirements and statutory responsibilities. References to "prototypical" margins are of little assistance either in divining the Congressional intent or applying those standards properly.

Finally, PGE and the IOUs argue that BPA's treatment of revenue taxes unreasonably deprives the Residential Exchange participants of statutory benefits. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 39; PGE Brief, WP-02-B-GE-01, at 10. PGE poses the argument as follows:

> If the industrial margin is set artificially low by excluding costs of taxes that properly should be included, the IP rate will be set artificially low. Setting an artificially low IP rate results in a higher PF Exchange rate, and decreases Residential Exchange benefits. This result is inconsistent with the goal of providing an equitable share of FCRPS benefits to investor-owned utilities' residential and small farm customers. Including revenue taxes in the margin will result in an increase in the value of Residential Exchange benefits of $8,322,000 per year.

PGE Brief, WP-02-B-GE-01, at 10.

In the Draft ROD, BPA maintained that it is unlikely that allocating the entire amount of revenue taxes to the margin would result in any change in the rates charged to the DSIs. Based on PPC's adjustment to the margin of 1.18 mills/kWh if revenue taxes are included, Hansen *et al.*, WP-02-E-PP-06, at 29, BPA concluded that the resulting IP rate would still be less than the floor rate. Thus, there would be no change in the PF Exchange rate and no detriment to Residential Exchange participants. Draft ROD, WP-02-A-01, at 15-13.

The IOUs take issue with this conclusion. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 32. They do not demonstrate the analytical basis for their calculation. Nor do they show how the alleged “interrelationship between the floor rate calculation and margin calculation” negates BPA’s conclusion. However, it is not necessary to determine whether BPA or the IOUs is correct. Speculation about different outcomes for the Residential Exchange program depending on treatment of revenue taxes is relevant primarily for assessing how important it is to decide the issue at this time. For that purpose, BPA accepts that there is significant disagreement as to potential effects on the Residential Exchange.

It should also be noted, however, that even if revenue taxes were deemed “typical,” it does not necessarily follow that the entire amount would be included in the margin. The Joint DSIs, for example, argue that it would not be unreasonable to allocate such costs across the spectrum of cost categories to the extent that each category contributes to the amount of revenue tax incurred:

> If it were determined that revenue taxes were both “typical” and “margin”, only a small portion of the taxes should be included in the Industrial Margin. Revenue taxes are assessed as a percentage of the sales price of the electricity. The sales price reflects four cost components: production, transmission, distribution, and “other overhead costs”. Therefore, the contribution of each of the components to the sales price is incurring the same percentage in contributing to the amount of revenue taxes collected. Therefore, if a utility’s revenue tax was a particular percentage of the total bill, and since the total bill is determined by each of the components, the revenue tax can be assigned to each of the components based on costs causation.

Schoenbeck *et al.*, WP-02-E-DS/AL/VN-06, at 9.

The IOUs suggest that such an outcome would understate the margin with respect to distribution costs, because BPA uses DSI delivery facility charges as a surrogate for distribution costs. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 39. The IOUs cite nothing in the record to support their conclusion. Moreover, the argument ignores issues that could arise in collecting information necessary to calculate the level of taxes that might reasonably be included in the distribution component attributable to the margin.

In response to the concern expressed by the IOUs that BPA has not delineated these issues, IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 32; BPA’s witness noted at cross examination the economies of scale associated with large industrial consumers, Tr. 1851. Such factors make it likely that a much smaller cost for distribution facilities would be associated with large industrial customers than would be the case for high density residential load. This would also mean that large industrials would bear a smaller portion of the tax liability associated with such property. Making this determination accurately, however, would require more data than has been solicited in any margin study to date. Moreover, with respect to the franchise fees promoted by the IOUs for inclusion in the margin, those generally attach solely to business conducted within specifically defined municipal boundaries. It is not at all clear large industrials are located within such boundaries. Again, this is a type of information that has never been solicited in a margin study. In sum, the Administrator believes that substitution of DSI delivery facilities for distribution costs would remain a reasonable approach to this issue even if revenue taxes were included in the margin and allocated across the spectrum of cost categories.

To summarize the most pertinent findings, BPA concludes that:

(1) revenue taxes are not typical for purposes of calculating the industrial margin and should be excluded; and

(2) even if revenue taxes were deemed typical, it cannot be concluded that they should necessarily be allocated in their entirety to the margin; and

Decision

Washington is the only state in BPA's public agency service territory that levies a revenue tax. Because only one state levies such a tax and because less than a majority of preference customers are located in that state, it is reasonable to conclude that revenue taxes cannot be considered part of a "typical" industrial margin.

15.2.2 Margin Sample

Issue 1

Whether BPA erred in treating data from Utilities No. 9 and No. 31 differently, where one reflected the reported difference between the costs allocated to the industrial class and the other reflected revenues that the rates to that class will produce.

Parties' Positions

The DSIs argue that the cost of service analyses for Utilities No. 9 and No. 31 showed differences between the costs allocated to industrial customers and the revenues expected to be collected from those customers. The DSIs maintain that BPA erred by treating the two amounts differently. DSI Brief, WP-02-B-DS-01, at 24. The DSIs reiterate their earlier arguments in their brief on exceptions and note that the "Draft ROD's statement that the $40,000 revenue shortfall was associated in the cost of service analysis documentation of utility No. 9 with certain interest and other income is not support by the citation provided and is not supported by any evidence in the record." DSI Ex. Brief, WP-02-R-DS-01, at 9.

BPA's Position

BPA asserts that different treatment of costs apportioned to the margin category is appropriate due to factual differences reflected in the information reported by Utilities No. 9 and No. 31. Ebberts, WP-02-E-BPA-47, at 11. In connection with this issue, the Draft ROD made the following statement: "More specifically, this utility identified $60,000 from interest and other income in its cost of service analysis documentation that would be used to meet expected costs. Of this, $20,000 was functionalized to the capital expenditures category." Draft ROD, WP-02-A-01, at 15-15. As indicated in the statement itself, and as noted in the DSI brief on exceptions, this breakdown of costs does not appear in the WPRDS or in testimony. Instead, it comes from the underlying documentation. The DSIs are, therefore, correct that the information is not on the record, and the statement should, therefore, be redacted from the evaluation. This does not, however, change the professional judgment of BPA's witness to the effect that the information was sufficiently reliable to be included in the study and should be treated as a revenue credit. Ebberts, WP-02-E-BPA-10, at 9-11.

Evaluation of Positions

The DSIs note that Utility No. 31 reported, for its industrial customer class, anticipated revenues exceeding allocated costs by $240,000. DSI Brief, WP-02-B-DS-01, at 24. They point out that, consistent with prior practice, BPA assigned this "rate margin" to the "other" category for inclusion in the typical margin. *Id.* The DSIs go on to say Utility No. 9 reported, for its industrial class, anticipated revenues $40,000 less than the allocated costs, but BPA did not assign this negative rate margin to "other." *Id.* Instead, BPA apportioned the shortfall to production, transmission, distribution, and other. Ebberts, WP-02-E-BPA-47, at 11. The DSIs state that the practical effect was to overstate the margin attributable to this utility by inappropriately treating the negative margin as a revenue credit and spreading the amount across cost categories that are not included in the margin calculation. DSI Brief, WP-02-B-DS-01, at 24. They assert that, in fact, the utility had no identified revenue credit, just rates less than the allocated costs. *Id.* Such a shortfall, the DSIs argue, is no different than the positive rate margin for Utility No. 31, and it should be treated the same, *i.e.*, assigned to other. *Id.* The DSIs maintain that in prior margin studies, both positive and negative rate margins have been assigned to "other." *Id.*

BPA does agree that, in the case of Utility No. 31, the cost of service analysis showed a markup over expected costs of $240,000, which was properly assigned to the margin. Ebberts, WP-02-E-BPA-47, at 11. BPA disagrees, however, with the DSIs' claim that Utility No. 9 reported no identified revenue credit. In fact, the data reported by Utility No. 9 reflected a revenue source of $40,000 that would be used to balance expected costs with expected revenues. Ebberts, WP-02-E-BPA-47, at 11. BPA does not consider this amount to be a "negative" margin below expected costs, but rather a source of income that would be used to meet some part of the various categories of expected costs. Therefore, it was apportioned "based on relative shares of revenue requirement" consistent with the methodology adopted in BPA's initial proposal. Ebberts, WP-02-E-BPA-22, at 6.

Thus, BPA was correct in considering this amount a revenue credit rather than margin. *Id.* BPA established in its direct testimony that such income credits (if not functionalized already by the utility to a production, transmission, or distribution category) would be apportioned to the various cost categories based on relative shares of revenue requirements. Ebberts, WP-02-E-BPA-22, at 6. BPA's treatment of Utility No. 9 is consistent with the treatment of all other utilities that identified an income credit and did not specifically functionalize this income credit to cost items that would be apportioned to the production, transmission, distribution, or other category. *Id*.

<u>Decision</u>

BPA did not err in its treatment of Utilities No. 9 and No. 31. The treatment of cost of service analysis data from these two utilities is consistent with established methods identified in BPA's direct testimony. To the extent that the data for the two utilities were characterized differently as margin on the one hand and a revenue credit on the other, that conclusion reflects a reasonable assessment of two different factual situations.

<u>Issue 2</u>

Whether Utilities No. 5 and No. 14 should be excluded from the margin sample because they provided data that were not in the form of independently verifiable business records.

<u>Parties' Positions</u>

The DSIs argue that the preference utilities providing the margin data would benefit from somewhat lower rates if the margin were larger. DSI Brief, WP-02-B-DS-01, at 22-23. While the DSIs do not maintain that this fact necessarily indicates bias in the data supplied, they argue that, under such circumstances, the data supplied by utilities should be verifiable. *Id*. Materials such as cost of service analyses and financial statements are used for many business purposes, and the DSIs believe margin data should be limited to such "business records." *Id*. The DSIs conclude that, because Utilities No. 5 and No. 14 were not required to submit such independently verifiable documentation, they should be excluded from the margin sample. *Id*.

Finally, they argue that the information should be excluded because it consists of unsworn statements that do not fall within any exception to the hearsay rule. *Id*. at 23. In their brief on exceptions, the DSIs argue, without citing any support, that BPA's determination that the DSIs waived this argument by failing to move to strike the unverifiable data is contrary to law. DSI Ex. Brief, WP-02-R-DS-01, at 9. The DSIs state that they were "arguing that BPA should give no weight to the evidence, not that it must be struck from the record as violative of some rule of evidence." *Id*. at 10.

PPC argues that both of these utilities had industrial customers on special contracts. Hansen *et al.*, WP-02-E-PP-09, at 36. According to PPC, it is entirely reasonable that they would be reluctant to provide these contracts even under the protection of a confidentiality agreement, given the increasingly competitive nature of the industry. *Id*. PPC points out that the DSIs are incorrect in asserting that a single page of information was the only data provided. *Id.* In addition to initial submittals of information, both utilities were receptive to followup telephone calls clarifying and expanding upon their earlier responses. *Id*. This additional information has also been available to parties willing to sign the confidentiality agreement. *Id.*

BPA's Position

BPA maintains that it was proper to include Utilities No. 5 and No. 14 in the sample. The two utilities confirmed that they understood what costs were to be included and how these costs would be identified in a cost of service analysis had one been available. These independent confirmations were sufficiently reliable to conclude that the data should be included in the sample. Ebberts, WP-02-E-BPA-47, at 10.

Evaluation of Positions

The Joint DSIs argue that Utilities No. 5 and No. 14 did not provide a cost of service analysis or any other reasonable documentation of the "margin" costs they submitted. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-01, at 14-15. Instead, these utilities simply asserted in response to PPCs original request for data that their margin was a certain number. *Id*. The Joint DSIs insist that such assertions are not credible in light of BPA's own recognition that

> [T]he 'industrial margin' is a term of art employed in section 7(c)(2) of the Northwest Power Act. Although to some extent the industrial margin is intended to mimic the margins that BPA's preference customers add to their retail industrial rates, it is not a calculation the utilities themselves do. It is not an aspect of utility ratemaking.

Id., quoting 1996 ROD, at 153.

Therefore, the Joint DSIs suggest that BPA has inappropriately permitted these two utilities to make their own margin determination.

Contrary to these assertions, BPA did not ask the utilities to do their own margin calculation. BPA asked only that these utilities identify costs that would not be considered costs associated with production, transmission, or distribution, which is the same type of information BPA has relied upon in previous margin studies. Ebberts, WP-02-E-BPA-47, at 10-11.

BPA is required by section 7(c)(2) to perform sufficient analysis to develop the industrial margin calculation. However, utilities cannot be compelled to provide the information needed for the analysis. In fact, utilities have grown increasingly reluctant to cooperate in providing utility and industry data to BPA for industrial margin studies. Ebberts, WP-02-E-BPA-22, at 2. Utilities have valid concerns about publicly displaying customer specific information of such a sensitive nature, particularly given the development of an increasingly competitive power market. *Id*. In this instance, BPA could obtain the information only by signing a confidentiality agreement, which was required of all parties who wanted access to the data. *Id*. at 3. Of course, confidentiality agreements are not uncommon in the ratemaking setting, and BPA would have been hard pressed to acquire equally substantial information without agreeing to such an arrangement.

Compounding the problem of the utilities' reluctance to provide information is the relatively small population from which meaningful data can be collected. In this rate case BPA identified only 35 utilities with industrial loads large enough to qualify, even though the 3.5 MW threshold is only a fraction of the size of the typical DSI load. *Id*. BPA requested data from all 35 and received from 22 utilities responses that were considered useable. *Id*. at 4. Given these difficulties, it would be unrealistic to require a statistically directed random sampling of qualifying utilities for purposes of collecting data for the Industrial Margin studies. Instead, BPA tries to work cooperatively with utilities so that they will voluntarily provide as much information as possible for use in the margin study.

In this case, BPA knew prior to conducting the survey that there had been a significant increase in the number of utilities and industries that have entered into nontraditional contracts. Ebberts, WP-02-E-BPA-47, at 9. It was also obvious that the costs of providing service for such arrangements might not be reflected in a cost of service analysis. Therefore, in addition to the standard cost of service analysis, BPA also requested information about these special types of contracts. *Id*. When Utilities No. 5 and No. 14 indicated that they each had a nontraditional contract not reflected in a cost of service analysis, it was reasonable to attempt to verify the nature of the information so that it could be used if possible. *Id*. at 10.

In each instance, BPA requested PPC to verify that the margin number provided represented the cost of serving the two industrial customers over and above the cost of power, transmission, and distribution. *Id*. As PPC points out, both utilities participated in followup telephone calls, clarifying and expanding upon the written information they provided. Hansen *et al.,* WP-02-E-PP-09, at 36. BPA did not rely solely on the PPCs framing of the questions for clarification. Tr. 1896. Instead, BPA provided the PPC with the types of questions to ask. *Id*. Based on the questions asked and the responses received, BPA decided that the information should be included in the Industrial Margin study.

Utility No. 5 confirmed that it had provided the same number that would have been calculated from a cost of service analysis had a cost of service analysis been provided. Ebberts, WP-02-BPA-E-47, at 10. In other words, had a cost of service analysis been provided, BPA would have accepted the utility's functionalization and allocation method and excluded from the margin calculation costs related to production, transmission, and distribution. *Id*. Utility No. 14 also indicated that it did not have a cost of service analysis for its single industrial customer, which was receiving service under a special contract. *Id*. The utility confirmed that it was serving the customer at a cost that would have been entirely assigned to either production, transmission, or distribution had a cost of service analysis been available. *Id*. In other words, there would have been no costs assigned to any "other" category, with the result that a margin of 0 mills/kWh was applied to this utility. *Id*. at 11. Of course, there would be no basis to question the reliability of a utility that was reporting no margin in light of the utility's self-interest, as identified by the DSIs, in reporting a higher margin.

Thus, BPA had every reason to have confidence regarding one utility's report and ample assurance that the other was not overstating its margin. Given these circumstances, the information is sufficiently reliable to be included when balanced against the alternative of working with a smaller, and less representative, data base.

In the Draft ROD, the Administrator stated that the evidentiary arguments were not raised at the appropriate time by motion and were therefore waived. Draft ROD, section 1.1.3. In their brief on exceptions, the DSIs claim that they were not arguing that the evidence should be stricken, only that it should be given no weight. This position is unconvincing in light of the language in the DSI initial brief:

> The information regarding these utilities *does not constitute evidence*. . . . *BPA should exclude both utility No. 5 and No. 14 from the margin sample* to be consistent with BPA's prior wise practice of requiring the margin to be based on verifiable information.

DSI Brief, WP-02-B-DS-01, at 23 (emphasis added). Arguing that information does not constitute evidence and should therefore be excluded is a far cry from explaining why a piece of evidence should not be given significant weight. One is accomplished by allowing the finder of fact to remain the final judge of the weight and sufficiency of the evidence. The other requires a motion at the appropriate time with the intended result of depriving the fact-finder of the ability even to consider the information. It is obvious from the above language that the DSIs were attempting the latter. They cannot now exhume the argument by rewriting the position taken in the initial brief. To permit such reversals in the brief on exceptions would render the initial brief meaningless by making the parties' positions moving targets until the brief on exceptions. Moreover, if parties could simply recharacterize every motion to strike as an argument regarding the weight to give a piece of evidence, then evidentiary motion practice in this proceeding would be essentially pointless. The DSIs failed to move to strike the evidence at the appropriate time, and the argument is therefore waived.

Moreover, the supplied data are most certainly relevant to the margin calculation and, even if they are hearsay, the procedures do not categorically require their exclusion. The Administrator certainly agrees that the cost of service data and other forms of data that are subject to "independent verification" are preferable. However, the Administrator also believes that it is important, in light of changes in the power markets, to include relevant data about nontraditional service arrangements that may not be reflected in a cost of service analysis. In fact, BPA has accepted this kind of information in previous Industrial Margin studies. A nearly identical form of data was accepted and used in the 1996 Industrial Margin Study. Ebberts, WP-02-BPA-E-47, at 10. On balance, therefore, the Administrator finds that it is reasonable to include this information in the sample and to give it the same weight as any other included information.

None of this should be interpreted as minimizing the Joint DSIs' legitimate concerns about the availability and reliability of data both now and in the future. There is likely to be increased pressure to ensure confidentiality and a continuing reluctance on the part of utilities to provide the type of information needed to calculate the margin. The reliability of data will continue to be monitored in future cases.

Decision

It is reasonable, under the circumstances presented here, to include the data provided by Utilities No. 5 and No. 14 in the margin study.

15.3 DSI Floor Rate

Section 7(c)(2) of the Northwest Power Act provides that the rate developed pursuant to that section "shall in no event be less than the rates in effect for the contract year ending on June 30, 1985." 16 U.S.C. §839e(c)(2). This is the so-called "floor rate test." Simply stated, the floor rate test ensures that BPA recovers revenues from its DSI customers in the current rate test period equal to or greater than the revenues it would recover in the test period using the applicable IP rate in effect on June 30, 1985. Ebberts, WP-02-E-BPA-22, at 10. In the 1985 rate case, the Administrator decided that the IP-83 Standard rate was the appropriate basis for conducting the floor rate test, and that rate has been the basis for the test in every subsequent rate case. 1985 ROD, WP-85-A-02, at 182.

15.3.1 Appropriate Rate Schedule: IP-83 Standard v. IP-83 Premium

Issue

Whether the IP-83 Standard Rate should be replaced by the IP-83 Premium Rate for the 2002-2006 rate period.

Parties' Positions

PPC argues that the DSIs are being offered up to 1,400 aMW in the form of a firm power block product. PPC Brief, WP-02-B-PP-01, at 54. Therefore, PPC concludes, the applicable "rate in effect" in 1985 which should serve as the basis for the floor rate is the Premium Rate, which was available for the sale of 100 percent firm Federal power to the DSIs. PPC Brief, WP-02-B-PP-01; *see also,* PPC Ex. Brief, WP-02-R-PP-01, at 10. The IOUs and SUB make similar arguments. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS/EN-01, at 44-47; SUB Brief, WP-02-B-SP-01, at 4; *see also*, IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 34-36, and SUB Ex. Brief, WP-02-R-SP-01, at 4.

BPA's Position

BPA maintains that the IP-83 Standard rate is the appropriate basis for the floor rate. It establishes an equitable baseline of rate protection for preference customers while maintaining an appropriate degree of stability and predictability in the DSI rates. Ebberts, WP-02-E-BPA-47, at 5.

Evaluation of Positions

The PPC states that the IP-83 Standard rate schedule reflected a product that melded firm service with nonfirm service:

> Calculation of the IP-83 Standard Rate melds the cost of providing firm service to the bottom three quartiles of the DSI load, plus first quartile transmission costs allocated in the Cost of Service Analysis, with the generation cost assigned in the WPRDS. Generation costs are assigned based on the opportunity cost of

> providing service to the first quartile. Under the IP-83 Standard Rate, all service to the top quartile is priced at the generation portion of the average Nonfirm Energy rate.

PPC Brief, WP-02-B-PP-01, at 54, quoting WP-83-FS-BPA-07, at 41.

The PPC interprets this language to mean that the 1985 Standard rate reflected interruptible service for one-quarter of the DSI loads. *Id.* PPC then argues that service under the IP-83 Standard rate was a product of "lesser quality" than the current DSI service proposal of up to 1,400 aMW in the form of a firm power block product. *Id*. Therefore, PPC concludes, the IP-83 Standard rate was not the "rate in effect" in 1985 for the type of product now being offered, and it should be supplanted by the more applicable IP-83 Premium Rate, which was available in 1985 for the sale of 100 percent firm Federal power to the DSIs. *Id*. at 55.

In testimony, PPC described the difference between the Standard and Premium rates as follows: "The IP-83 Standard rate is for service to DSIs by BPA with 75 percent firm and 25 percent non-firm resources. The IP-83 Premium rate is for service to DSIs by BPA with 100 percent firm resources." Hansen *et al.*, WP-02-E-PP-06, at 23. Unfortunately, PPC does not account for the fact that service provided to the first quartile was quite reliable and extremely unlikely to be interrupted. In the 1983 rate case, for example, BPA forecasted approximately 76 percent service to the first quartile based on nonfirm resources; however, since the first quartile was also modeled as a market for firm surplus, the end result was a "much higher percentage of service to the first quartile." 1983 ROD, at 254. Thus, service to the first quartile was reinforced by being served as a priority market for both nonfirm energy and unmarketed firm surplus. Such service cannot accurately be characterized as wholly "nonfirm."

Again, in 1985, the Administrator described the nature of first quartile service as being a highly dependable quality of service:

> [T]he DSI first quartile, under rate case assumptions, would be the first market served with nonfirm energy . . . [Also] the first quartile could be served with provisional drafts, while nonfirm energy sales made under the NF rate are not made using provisional drafts . . . Although BPA operates its resources to serve the first quartile on a firm basis . . . [r]estrictions to the first quartile could occur if either adverse water conditions arose or if BPA were able to make more sales of surplus firm energy at the SP rate than it currently expects . . . Current estimates indicate, however, that surplus firm energy will be available during the rate period . . . [T]he probability is that, even under critical water planning, BPA would have to restrict service to only that portion of the first quartile not served with unsold surplus firm power; that is, power made available during the fish migration assistance period and the precritical period and unsold surplus during the other 9½ months . . .

1985 ROD, at 150.

Thus, BPA not only projected adequate firm surplus to "firm up" the first quartile, but also operated its system in a manner that created a very low probability of first quartile interruption. Even in the worst possible scenarios, a significant amount of top quartile service was, in all respects, firm service. In typical years, when BPA generated nonfirm energy, the entire quartile was firm. *Id*. at 151. As the Administrator observed: "In effect, the DSIs receive a product that BPA attempts to provide as firm while charging only a nonfirm energy price." *Id*.

Because top quartile service has been essentially firm from an operational standpoint, the question of computing its value has always been difficult. As the Administrator noted in 1985:

> On BPA's system, nonfirm energy is generally available in most years. Because of the nature of DSI operations, the DSIs provide a fairly stable market for nonfirm energy. As a result of this relationship, the value to BPA of the interruptibility of the first quartile is more closely related to the nonfirm energy market than to the acquisition of an alternative resource.

Id. at 203. A similar point was made in 1983:

> Assigning costs to the first quartile is a difficult issue because of the unique character of service provided the first quartile. Ideally, the method chosen would reflect the nonfirm nature of the service from a planning perspective, the near-firm nature of the service on an operational basis (that is, service of the first quartile is high on the priority list of uses of nonfirm energy), and the return provisions for the provisional drafts. Unfortunately, it is very difficult to calculate the cost of these service characteristics, either on an embedded cost of service basis or some incremental cost basis.

1983 ROD, WP-83-A-02, at 255.

The unique configuration created by first quartile service does differ, to some degree, from the firm service provided to the DSIs since 1996 and offered again as a result of this proceeding. The question is whether the difference is significant enough to warrant a radical change in the way the floor rate has been calculated. As noted above and in BPA's testimony, the availability of firm surplus and nonfirm energy in typical years meant that the first quartile was virtually firm. Tr. 1707. Therefore, the product offered under the Premium rate schedule was not an attractive product. In fact, BPA's testimony indicates that no sales were made under that rate schedule. Tr. 1808. In this vein, it is also important to remember that the floor rate test is a revenue test, *i.e.*, it ensures that the DSI rates will recover revenues at least equal to the revenues recovered under the rate "in effect" on June 30, 1985. This fact, as well as the factors related below, raise numerous questions regarding the wisdom of treating a rate schedule which generated no significant revenues as being "in effect" for purposes of calculating the floor rate.

The 1985 ROD stated that the purpose of the DSI floor rate was to ease the transition from cost-based to equity-based DSI rates for BPA's non-DSI customers. 1985 ROD, WP-85-A-02, at 180. On that basis, BPA decided not to use the Incentive rate loads and revenues as the basis for the floor rate calculation, even though that rate was actually being used and generating significant revenues during some parts of the year. *Id*. The rationale was that using the Incentive rate would have lowered the floor rate, potentially harming BPA's non-DSI customers in the transition from cost-based to equity-based DSI rates. *Id*. At the same time, however, certain costs were removed from the IP-83 Standard rate to prevent the floor rate from including inappropriate costs caused by unique and extraordinary historical events. Failure to make these adjustments would have resulted in a "perpetual windfall" to non-DSI customers. *Id*. at 184. Thus, the development of the floor rate reflects the twin goals of providing adequate rate protection without unduly inflating the DSI rates.

The issue of the DSI floor rate was addressed again in the 1987 ROD. At that time, consistency was a major concern, and one issue specifically addressed was whether the BPA methodology for calculating the level of the floor rate would result in a stable floor rate over time. 1987 ROD, WP-87-A-02, at 134. In fact, other parties (including WPAG) supported BPA in arguing for a methodology that would provide "predictability and stability" to the floor rate calculation. *Id*. BPA decided the method for calculating the floor rate would result in a stable floor rate. *Id*. at 135.

PPC's proposal, by contrast, would introduce significant uncertainty into the floor rate calculation. As BPA pointed out in testimony:

> The [PPC] testimony identifies a difference in the quality of service being provided to DSIs in this rate case. However, PPC offers no examples where BPA has previously adjusted the floor rate to account for differences in service quality, in spite of the fact that DSIs received 100 percent firm service in the 1996 rate case. Adopting PPC's proposal would raise a number of questions. For example, BPA's current proposal for DSI service is roughly half the current service level. This arguably raises a service quality issue that should also impact the floor, which in turn raises the issue of how to deal with any service quality issue for which no appropriate 1983 analogue can be identified.

Ebberts, WP-02-E-BPA-47, at 5-6.

Instead of providing stability, the PPC proposal would make the floor rate a moving target by opening the door to a plethora of continuing "service quality" arguments that could be raised in support of any number of adjustments to the floor rate. The primary result would be to undermine the stability and predictability that the floor rate has provided for 15 years.

SUB takes issue with a number of arguments posited by BPA in the Draft ROD. SUB argues that BPA erred by using "retrospective logic" in determining that first quartile service to the DSIs was "virtually firm." SUB Ex. Brief, WP-02-R-SP-01, at 4. SUB insists that the IP-83 Premium rate was the applicable rate "in effect" and should be the basis for the floor rate, concluding that firmness of service to the DSIs is a moving target and the firm product sale to the DSIs should drive the floor rate. *Id*. at 5.

The Administrator does not find these arguments persuasive. The statute requires that, in some circumstances, a rate from a prior rate period be used to establish the rates for the current rate period. 16 U.S.C. §839e(c)(2)(C). It is difficult to understand how that could be accomplished without using, to some degree, "retrospective logic." BPA's witness made the salient historical point clearly during cross-examination:

> BY MR. MARSHALL:
>
> Q. Standard rate power can be interrupted. Premium rate power cannot be interrupted, it's firm, right?
>
> A. (Mr. Ebberts) Well, the fact of it was the standard rate was firm. That product was firm.
>
> Q. As it turned out, but it could be interrupted, right?
>
> A. (Mr. Ebberts) It was firm.
>
> Q. Standard rate is firm and premium is firm. Is that what you're trying to say, Mr. Ebberts?
>
> A. (Mr. Ebberts) We ha(d) 500 megawatts of firm surplus allocated to that top quartile. That load was firm.

Tr. 1797. SUB complains that BPA has made a "moving target" of firmness of service to the DSIs. As indicated above, such a statement is inaccurate. The quality of service to the DSIs has, on a historical basis, has been largely consistent. The existence of a Premium rate that was theoretically available, but never used, provides no basis for making the floor rate itself a moving target.

In summary, the floor rate was intended to provide stable and predictable protection against cost shifts to non-DSI customers without creating a "windfall" for non-DSI customers. The IP-83 Standard rate has been used as the basis for that test since 1985. Now, 15 years into the "transition" from cost-based DSI rates to equity-based DSI rates, this rate case is the first in which the floor rate will set the DSI rate. As calculated in the initial proposal, the floor rate (20.98 mills/kWh) differs significantly, but not dramatically, from the equity based IP rate (19.57 mills/kWh). By contrast, as PPC points out, use of the Premium rate as the basis for the floor rate would increase the DSI rates dramatically, to 25.73 mills/kWh (excluding transmission costs). Hansen *et al.*, WP-02-E-PP-06, at 24. Such a result would not be consistent with establishing a stable and predictable baseline of rate protection without creating a windfall to non-DSIs. Instead, PPCs proposal would introduce a rate disparity that cannot be justified by the facts, given the actual nature of first quartile service provided to DSIs in the 1980s. The floor rate was intended to be protective--not punitive--and such a proposal must be rejected.

<u>Decision</u>

The IP-83 Standard rate has provided a stable, predictable baseline of rate protection since 1985, and will not be replaced by the IP Premium rate as the basis for the floor rate calculation.

15.3.2 Non-Recurring Costs: Surplus Firm Revenue Deficiency

Issue

Whether the surplus firm open market revenue deficiency should be treated as a non-recurring cost and removed from the IP-83 Standard rate for purposes of calculating the floor rate.

Parties' Positions

The DSIs argue that because BPA does not forecast any surplus firm open market revenue deficiency in the upcoming rate period, BPA should remove the corresponding IP-83 revenue deficiency from the floor rate in this case. DSI Brief, WP-02-B-DS-01, at 5; *see also*, DSI Ex. Brief, WP-02-R-DS-01, at 10. Alcoa/Vanalco make a similar argument. They maintain BPA is incorrect in asserting that the floor rate test requires that BPA recover revenues from the DSI customers in the test period equal to or greater than the revenues it would recover in the test period using the applicable IP rate in effect on June 30, 1985. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, citing Ebberts, WP-02-E-BPA-22. Alcoa/Vanalco argue that BPA's description of the floor rate test inappropriately fails to consider the elimination of non-recurring costs (among other things). *Id.*

PPC claims such an adjustment to the statutory floor rate test is not justifiable. PPC Brief, WP-02-B-PP-01, at 55.

BPA's Position

BPA argues that exclusion of the surplus deficiency would simply be an adjustment to reflect market conditions projected in this particular test period. Ebberts, WP-02-E-BPA-47, at 2. Such a cost cannot be characterized as a non-recurring cost, and there is no indication that its continued inclusion in the IP-83 Standard rate creates any kind of windfall for non-DSI customers. *Id*. at 3.

Evaluation of Positions

The DSIs state that, in 1985, the Administrator approved a floor rate methodology based upon the IP-83 Standard rate, which was adjusted to remove costs of the "deferral" and to reflect the fully "phased-in" newly revised Average System Cost Methodology. DSI Brief, WP-02-B-DS-01, at 7, citing 1985 ROD, at 190. The DSIs state that the Administrator rejected other adjustments proposed by the DSIs, but only on the basis that such adjustments were "inappropriate for the limited purpose of determining the DSI floor rate in the 1985 rate filing." *Id.* at 8.

The DSIs then note that in the 1996 rate case, after the IP/PF link expired, the Administrator again faced arguments from the DSIs regarding the need to remove certain additional non-recurring costs from the floor rate. *Id.* The DSIs state that the Administrator affirmed BPA's position from the 1985 rate case that the floor rate, like all other rates, is prospective in nature and must be adjusted in setting future rates. *Id.* *See* 1985 ROD, at 185. They also note that the Administrator agreed that "the DSIs are correct that non-recurring costs should be excluded from future rates, including the floor rate." DSI Brief, WP-02-B-DS-01, at 8, quoting 1996 ROD, WP-96-A-02, at 220. *Id.* However, since the equitable 7c(2) rate exceeded the floor rate, the Administrator did not rule on the merits of the DSIs' proposed adjustment. *Id.* For that reason, the DSIs have proposed that the Administrator consider the issue in the present proceeding.

The DSIs state that the IP-83 Standard rate and the 1985 floor rate were developed at a time when BPA expected to have surplus firm power in excess of its existing and projected contractual obligations. *Id.* at 9. They maintain, as well, that in 1983 and again in 1985, BPA forecasted that a significant portion of this surplus firm power would be sold on the open market at prices below BPA's allocated costs of the power. *Id.* This created a revenue deficiency that had to be recovered through other power rates. *Id.* In 1983, the surplus power was deemed to consist of the exchange power, and the revenue deficiency was allocated primarily to the IP-83 rate. *Id.* Now, however, BPA's regional customers seek to purchase power in excess of BPA's expected power inventory. *Id.* The DSIs argue that because BPA does not forecast any surplus firm open market revenue deficiency in the upcoming rate period, BPA should remove the corresponding IP-83 revenue deficiency from the floor rate in this case. *Id.* More broadly, the DSIs believe that the floor rate should be reviewed, and if necessary revised, in each rate case to assure that costs which do not recur in the BPA revenue requirement for that specific case are not included in the floor rate. *Id.*

BPA disagrees with the DSI argument. In 1985, the only time the issue has been considered on its merits, the Administrator removed only two items from the IP-83 rate on finding that they were non-recurring costs. In 1985, the Administrator recognized that "it is appropriate to examine the IP-83 rate structure to determine if any components might provide BPA's non-DSI customers a perpetual windfall." 1985 ROD, at 186. The Administrator found further that two of the DSIs' proposed adjustments had merit, *i.e.*, "the adjustments for the deferral and the phase-in of the new ASC methodology." *Id*. at 187. With regard to the deferral, the Administrator said:

> The treatment of the deferral was an unusual attempt by BPA to recover in its 1983 rates the unrecovered costs from previous rate filings. As a result, the 1983 rates were increased for previously unrecovered costs. It would be unfair to the DSIs to incorporate these costs in post-85 rates by using an IP-83 rate that has not been adjusted to account for the effects of the deferral.

Id.

Thus, the Administrator found that this event was "unusual." In other words, there was a very low probability that the event would occur again and then be treated, for ratemaking purposes, in a manner that would be analogous to treatment of the deferral in 1983. Instead, leaving the deferral costs in the IP-83 Standard rate was likely to result in a windfall for non-DSI customers by collecting multiple times the amount of deferral costs originally allocated to the DSIs. *Id*. at 188.

Similarly, the Administrator noted that "[t]he phase-in of the new Average System cost methodology is also an unusual event that unduly affects the average 1983 DSI rate." *Id*. The phase-in of the new methodology was "a short-term measure adopted to benefit other customers" and its specific purpose was "to avoid a sudden large increase in retail rates." *Id*. Retaining those costs in the IP-83 Standard rate would result in an "artificially high" DSI rate and impede "a smooth transition to post-85 rates." *Id*.

Thus, in both instances, the removed cost had been triggered by an unusual event, and that event was dealt with, as a matter of policy choice, in a manner that had the effect of temporarily skewing the IP-83 Standard rate. Continued inclusion of such an unusual temporary adjustment would have, in both instances, inflated the DSI rate artificially, disrupting the transition from cost-based to equity-based rates.

The same cannot be said for the surplus firm open market revenue deficiency. First, it is not triggered by an unusual event, but is instead a natural product of market forces which are constantly at work. As the Administrator noted, in denying the DSIs' request in 1985 for surplus power adjustment: "Both the availability and marketability of surplus power is subject to a great deal of uncertainty." *Id*. at 189. While the DSIs' optimistic portrayal of BPA's future market position is refreshing, it is by no means certain. It should be recalled that a mere four years ago, the Administrator published a ROD which included the following statement:

> BPA's customers, and the large industrial customers that many of them serve, all are searching actively for new lower cost suppliers . . . Parties representing every segment of BPA's customer base, investor-owned utility, direct-service industry, and public utility, have acknowledged the fact that BPA is faced with an increasingly competitive market . . . Most have urged BPA to take the actions, consistent with its statutory obligations, that are necessary to become more competitive . . . These same parties have acknowledged that BPA must compete in this market if it is to stay in business and collect sufficient revenues to meet its statutory obligations.

1996 ROD, at 16.

While BPA appears poised to be a low-cost provider for the coming rate period, that standing, in some ways, when compared to 1996, simply reflects the fact that current market conditions can and do change in a fairly short time frame. As BPA's testimony pointed out:

> There are good reasons why the surplus deficiency should not be characterized as non-recurring. BPA is making long-term (five-year) purchases in advance of the close of Subscription for approximately 1,100 average megawatts to augment the Federal Base system. It is possible that at some time during the next five year rate period, federal loads could change, and therefore, BPA could experience a firm revenue deficiency of the nature found in the Industrial Firm Power (IP-83) Standard rate. In addition, in any future rate case, the full costs of any BPA firm surplus may exceed market prices for various reasons.

Ebberts, WP-02-E-BPA-47, at 2.

Thus, the surplus deficiency is not "unusual" in the sense that term has been applied to previous adjustments. Moreover, the 2002 DSI rates are well below projected market prices, and they do not differ greatly from the rates of other customers. Thus, continued inclusion of the surplus revenue deficiency does not appear to be artificially skewing the DSI rates, creating a perpetual windfall for other customer classes, or causing serious disruption to the smoothness of the transition to a new rate directive that has now been applicable for 15 years. In sum, the DSI arguments for another adjustment are not persuasive.

The position adopted by Alcoa/Vanalco is even less compelling. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 70-71. Alcoa/Vanalco state that the purpose of the floor rate is to keep costs paid by the DSIs from being shifted to other customers. *Id.* at 70, 71. They state that to the extent BPA costs that were included in the rates in effect for the year ending July 30, 1985, are eliminated or reduced, the floor rate can be reduced without cost shifts to other customers. *Id.* at 70. They go on to maintain that BPA is incorrect in asserting that the floor rate test requires BPA to recover revenues from the DSI customers in the test period equal to or greater than the revenues it would recover in the test period using the applicable IP rate in effect on June 30, 1985. *Id.* at 71, citing Ebberts, WP-02-E-BPA-22, at 10. Such an assertion is inappropriate, they maintain, because it does not consider either the elimination of non-recurring costs, or the change in services provided through power rates in this case. *Id.*

Regardless of how the purpose of the floor rate is stated, the statutory directive is clear that a comparison should be made between proposed rates and the rates in effect in 1985. BPA has consistently treated the test as a revenue test and continues to believe that such a test is reasonable. Moreover, the argument that BPA's conception of the floor rate test fails to consider the elimination of certain types of costs is somewhat bewildering, inasmuch as those very issues appear to have been raised, recognized, and thoroughly considered in this proceeding.

PPC states that the adjustment to the statutory floor rate requested by the DSIs is not justifiable. PPC Brief, WP-02-B-PP-01, at 55. The PPC goes on to argue, however, that if BPA determines it is appropriate to adjust the floor rate to reflect changed market conditions, then it must similarly be appropriate to adjust the floor rate to correct for the service quality provided the DSIs under current market conditions. *Id.* The PPC states that to do otherwise would be arbitrary. *Id.* As noted above, BPA disagrees with the DSI position and is not removing the surplus deficiency as a non-recurring cost. It is not necessary, then, to address the service quality issue in this section, although that issue is fully addressed above.

Decision

The surplus firm open market revenue deficiency will not be treated as a non-recurring cost and will be included in the IP-83 Standard rate for purposes of calculating the floor rate.

15.3.3 Removal of Transmission Costs: IP-83 Standard v. IP-83 Premium

Issue

Whether it was appropriate for BPA to remove transmission costs from the IP-83 Standard rate to make an accurate floor rate comparison, in light of the fact that the IP-02 rate is for an undelivered product.

Parties' Positions

PPC argues that BPA is required to ensure that the total BPA rate to the DSIs fulfills the floor rate directive, and that BPA is therefore required to ensure that the transmission component of the floor rate test is performed. PPC Brief, WP-02-B-PP-01, at 53; *see also*, PPC Ex. Brief, WP-02-R-PP-01, at 11-12. The IOUs argue that the DSI floor rate test must compare the DSI floor rate (which bundled power and transmission rates) with DSI rates being established for the period beginning October 2001 for both power and transmission. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 44.

The DSIs agree in part with BPA. The DSIs point out that BPA has, as a matter of policy, unbundled its power and transmission rates in accordance with policies and standards developed by FERC and that BPA recognized that it was appropriate to adjust the floor rate to produce a power-only floor rate comparable to the IP-02 rate. DSI Brief, WP-02-B-DS-01, at 10.

BPA's Position

The IP rates, including the IP-83 Standard rate, have always been delivered product rates. Ebberts, WP-02-E-BPA-22, at 10. This means that both power and transmission costs were included in the test-period IP rate and IP-83 Standard rate. Beginning in this rate case, there will be separate rate cases for power and transmission. *Id.* To do this "power-only" comparison, the transmission costs included in the IP-83 Standard rate were removed. *Id.* Adjusting the IP-83 Standard rate in this manner, by removing the transmission costs from the rate, is the most straightforward and accurate approach. *Id.*

Evaluation of Positions

PPC states that section 7(c) of the Northwest Power Act sets forth the statutory rate directives applicable to the DSIs. PPC Brief, WP-02-B-PP-01, at 52. The PPC argues that one of those directives requires that the DSI rates "shall in no event be less than the rates in effect for the contract year ending June 30, 1985." *Id.* at 53. The PPC states that the statutory language is mandatory, not permissive. *Id.* PPC also argues that, while the BPA sale to a DSI customer is discretionary, the rate directives governing such sale are not. *Id.* Thus, the "floor rate" for a BPA sale to any DSI consists of "rates in effect for the contract year ending June 30, 1985." *Id.* In 1985, such rates included transmission costs. *Id.*, citing Hansen *et al.*, WP-02-E-PP-06, at 21-22. Because BPA is required to ensure that the total BPA rate to the DSIs fulfills the floor rate directive, PPC insists that BPA must ensure that the transmission component of the floor rate test is performed. *Id.* The PPC states that when it is performed, whether in this wholesale power rate proceeding or in a subsequent transmission rate proceeding, is of less relevance than the fact that transmission must be accounted for in the Administrator's determination of compliance with the floor rate test. *Id.* PPC expresses concern that, at the hearing, this witness could not say whether the BPA transmission rate case would address this issue. *Id.*, citing Tr. 1707.

Finally, the PPC argues that the separation of the two BPA rate proceedings cannot be used as a means to avoid a necessary component of the statutorily mandated DSI rate directives. *Id*. at 54. If the floor rate test is not completed in this case, it must be completed in the transmission case. *Id*. However, according to PPC, that would prevent the Administrator from making a final determination regarding these proposed power rates as required by the statute, 16 U.S.C. §839e(c)(1), until after the transmission rate case is completed. *Id.* In either case, functional separation of the business lines may not be relied upon to avoid a statutory directive that the Administrator is charged to employ. *Id.*

The IOUs offer fundamentally the same argument. The IOUs state that section 7(c)(2) of the Northwest Power Act requires that the DSI rate be no less than the rate in effect on June 30, 1985. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 86. The IOUs note that the DSI rate in effect at that time included both power and transmission charges. *Id.* The IOUs also maintain that the Northwest Power Act specifically requires consideration of not only power, but also transmission or delivery costs in establishing DSI rates. *Id.* Therefore, the DSI floor rate test must compare the DSI floor rate (which bundled power and transmission rates) from the 1985 rate case with DSI rates being established for the period beginning October 2001 for both power and transmission. *Id.*

The IOUs claim that BPA has failed to correctly perform this statutorily required floor rate test in its initial proposal by removing transmission costs from its floor rate test calculations. *Id.* The IOUs state that BPA concedes it is ignoring costs and rates for transmission in the floor rate test: "Beginning this rate case, there will be separate rate cases for power and transmission. Therefore, the floor rate test will be done for power only." *Id*., quoting Ebberts, WP-02-E-BPA-22, at 10.

The IOUs claim that BPA cannot ignore the statutory mandate to conduct a floor rate test for DSI rates for power and transmission merely because it has decided that "there will be separate rate cases. . . ." *Id.*

The IOUs also claim that BPA's proposal in this proceeding fails to establish a floor rate that is consistent with the statutory requirements of the Northwest Power Act. *Id.* The IOUs state that the PPC proposed that BPA resolve this problem by committing to include the transmission costs in a floor rate in the transmission case. *Id.* In its rebuttal testimony on this issue, BPA asserted that "[PPC's] proposals [to incorporate the transmission costs into the floor rate] are beyond the scope of the power rate case and will be dealt with in the transmission case." *Id.*, quoting Ebberts, WP-02-E-BPA-47, at 5. The IOUs claim that during cross-examination the same witness testified that he: (1) did not know if PPC's proposals to adjust BPA's floor rate for transmission costs were appropriate for the transmission case; (2) did not know what would constitute an appropriate subject for the transmission case; and (3) was not even aware of whether alternative proposals for calculating the transmission component of the floor rate test would be considered in the transmission case. *Id.*

The IOUs claim that BPA is simply failing to take the steps necessary to calculate the DSI floor rate. *Id.* at 87. The IOUs claim that the DSI power rate adopted in this proceeding must contain a provision for adjusting that rate, depending upon a comparison (in or after the transmission rate case) of the floor rate with the sum of the DSI power and transmission rates (PPC proposed a similar approach involving a "true-up" of the floor rate in the transmission case). *Id.* The IOUs state that subsequent floor rate tests, for periods after the BPA two-year transmission rate period, will also be required after development of BPA's transmission rates for each subsequent period. *Id.*

The DSIs note that BPA has, as a matter of policy, chosen to unbundle its power and transmission rates in accordance with policies and standards developed by the FERC. DSI Brief, WP-02-B-DS-01, at 10. The DSIs state that in its testimony, BPA staff recognized that it was appropriate to adjust the floor rate to produce a "power-only" floor rate comparable to the IP-02 rate. Ebberts, WP-02-E-BPA-22, at 10. *Id.* The DSIs state that BPA staff proposed to adjust the IP-83 Standard rate for this purpose by simply removing the identified transmission costs included in the IP-83 rate. *Id.* at 11.

The DSIs agree that it is appropriate and necessary to make the proposed adjustment, but they also go on to argue that the adjustment is not sufficient. *Id.* The DSIs claim that BPA's proposed adjustment to the floor rate by itself is inadequate to produce a power-only floor rate comparable to the IP-02 rate. *Id.* The DSIs state that FERC requires not only unbundled transmission rates, but also rates for unbundled ancillary services. *Id.* The DSIs state that as explained in BPA's direct testimony, BPA's TBL will need generation inputs from the FCRPS to provide ancillary and other transmission services. *Id.*, citing DeClerck *et al*., WP-02-E-BPA-26, at 1-2. The DSIs state that BPA allocated a portion of its generation costs to the TBL to be recovered in TBL rates for transmission and ancillary services. *Id.* The DSIs claim that in order to develop a power-only floor rate and avoid double-charging the DSIs for the cost of generation inputs for ancillary services, BPA must subtract the cost of such generation inputs from the IP-83 rate. *Id.; see also*, DSI Ex. Brief, WP-02-R-DS-01, at 10.

The DSIs state that unfortunately, BPA did not calculate and separately identify the cost of generation inputs to transmission and ancillary services in 1983. *Id.* There was no need to do so, because BPA's products were fully bundled. *Id.* Therefore, the certain and completely straightforward method used by BPA to adjust the IP-83 rate for transmission costs is not directly available for the generation inputs. *Id.* The DSIs propose a methodology for identifying the costs of generation inputs in 1983 that they claim is the functional equivalent of BPA's treatment of the transmission costs in the floor rate in this case. *Id.* at 10-11.

The DSIs state that the need for ancillary and other services to which BPA is providing generation inputs was not created by FERC's coining the term "ancillary services"; the need arises from the physics of the generation and transmission of power. *Id.* at 11, citing DeClerck *et al*., WP-02-E-BPA-26, *passim*. Moreover, the FCRPS that supplies such services and the WSCC operating requirements are essentially the same now as they were in 1983. *Id.*

The DSIs therefore conclude that it is reasonable to assume that the costs of generation inputs for ancillary services made up an equivalent percentage of BPA's total generation costs in 1983 to what they do today. *Id.* This follows from the fact that the Federal system is today as it was in 1983, 30 Federal hydro projects plus WNP-2. *Id.*

The DSIs state that in this case, BPA proposes to allocate costs equal to 3.5 percent of its generation revenue requirement to the generation inputs for ancillary services. *Id.* The generation revenue requirement allocated to the IP-83 rate in 1983 was $89.53 million, and 3.5 percent of such costs is $3.133 million. *Id.* The DSIs claim that this is a reasonable estimate of the costs of what are now called "generation inputs" that were allocated to the IP-83 rate. The DSIs state that this cost should be removed from the IP-83 Standard rate before the floor rate test is applied to a power-only IP-02 rate that does not recover the costs of such generation inputs. The DSIs state that leaving the costs of generation inputs in the floor rate would simply overcharge the DSIs without furthering any purpose of the floor rate test. The DSIs state that if this adjustment is adopted, the floor rate would be reduced from 20.98 mills/kWh as calculated by BPA to 20.81 mills/kWh. *Id.*

The DSIs state that BPA staff criticized this proposed adjustment as analytically inconsistent with the manner in which BPA adjusted the floor rate for transmission costs. DSI Brief, WP-02-B-DS-01, at 11. The DSIs agree with BPA staff that subtracting generation input costs that could be identified directly from the 1983 rate studies would be ideal. *Id.* But this option is simply not available. *Id.* at 12. The DSIs state that as noted above, there was no reason for BPA to separately identify such costs in 1983, and they were not separately identified. *Id.* The DSIs state it is not the case, however, that the methodology proposed by the DSIs is analytically inconsistent with BPA's transmission methodology, as alleged by BPA staff. *Id.*

The DSIs state that they did not propose that BPA use the cost of ancillary services in the current rate period as a surrogate for such costs in 1983. *Id.* The DSIs state that they proposed that, given the same physical system and operating requirements, it is reasonable to assume that the same percentage of generation costs were needed for generation inputs for ancillary services in 1983 as in the pending case. *Id.* The DSIs propose applying that percentage to the 1983 generation revenue requirement allocated to the IP-83 rate. *Id*. The DSIs state that the methodology is consistent with the methodology used by BPA for transmission costs in that it provides a proxy for calculating specific costs that were included in the IP-83 rates, and it is a reasonable methodology to avoid double-charging the DSIs for the cost of the generation inputs for ancillary services. *Id.*

As BPA points out, the IP-02 rate is an undelivered power rate. Ebberts, WP-02-E-BPA-22, at 10. It would have been inappropriate to compare an undelivered product rate to a delivered product rate in the floor rate test. *Id*. To have done so would have created an artificially high floor rate that included costs not present in the product being offered to the DSIs. As BPA's witness explained:

> Removing transmission costs from the calculation does not lower the floor rate in the sense that it permits the DSI customers to acquire power at a lower cost from BPA. Rather, it merely allows BPA to compare an unbundled test period power

> rate to an unbundled power floor rate, and no changes have been made, or are being proposed at this time, to any power costs in the IP-83 rate. Therefore the floor rate, after adjusting for the transmission component and substituting test period billing determinants, is unchanged.

Id. at 11.

Failure to make such an adjustment would be both unfair and arbitrary. Ultimately, BPA decided that the most straightforward approach to resolving this issue would be to remove known transmission costs from the IP-83 Standard rate. *Id.* BPA had considered an alternative methodology which was rejected:

> We also considered estimating the transmission rates that the DSIs may pay in the next rate period and adding those costs to the proposed IP-02 rate. Adjusting the IP-83 Standard rate by removing the transmission costs is the most straightforward and accurate approach. The transmission costs included in the IP-83 Standard rate are known and removing them from the rate involved no guesswork. However, transmission costs and rates that will be applicable to DSI customers in the next rate period are not known at this time, and an attempt to project those future costs would not be as accurate as removing known identifiable costs.

Id.

In other words, the alternative approach would have been to make a projection of transmission rates and use this estimate, knowing that it could later prove to be inaccurate. *Id.*

The DSIs agree with BPA's position that it was appropriate to perform a floor rate test based on a straightforward comparison of undelivered product rates. DSI Brief, WP-02-B-DS-01, at 10. However, the DSIs then claim that BPA did not go far enough, because it did not subtract additional costs beyond known transmission costs from the IP-83 Standard rate for what the DSIs claim should be ancillary service costs. *Id.* As BPA has pointed out, BPA accepted the method of subtracting known transmission costs from the IP-83 standard because it was a straightforward and accurate approach. Ebberts, WP-02-E-BPA-47, at 4. Adopting this method meant that BPA had to accept that it was not perfectly clear what specific transmission services were included in these costs. *Id.* It would not be possible to say with certainty whether some or none of these costs were associated with what would be considered ancillary services today. *Id.* In other words, the costs were not identified with enough specificity that there was any certainty of a high degree of accuracy with respect to separating transmission from ancillary service costs. For that reason, BPA determined that further analysis into costs not identified as transmission would not be reasonable, since there was no basis for determining whether new costs were being identified or if a cost was being double counted. *Id.*

This problem is also inherent in the DSI proposal to use the percentage of its generation revenue requirement to the generation inputs for ancillary services in this rate case (3.5 percent) as a proxy for the percentage of generation revenue requirement for ancillary services in the IP-83 rate that would be subtracted from the IP-83 Standard rate. DSI Brief, WP-02-B-DS-01, at 11. Again there is no way of knowing with certainty whether some of those costs are already included in the removal of identified transmission costs. Ancillary service rates are part of a relatively new pricing construct that attempts to identify and separate all of the services associated with providing reliable transmission. Ebberts, WP-02-E-BPA-47, at 4. Ancillary services were not identified at the time the IP-83 Standard rate was developed. *Id.* It is not clear that correlating costs recovered through that rate with present-day ancillary service cost projections is an accurate means of unbundling the floor rate. *Id.* This is why BPA believes that the DSI methodology could be used only if it were used for both ancillary service costs and transmission costs. Despite the DSIs' contention to the contrary, this would provide some assurance that there is no double-counting of costs that have already been subtracted from the IP-83 rate. *Id.*

As to the arguments of the IOUs and PPC regarding assurance that the transmission costs will be dealt with in the transmission rate case, PBL should not and does not have the authority to mandate policy or practice in the TBL rate case. Ebberts, WP-02-E-BPA-47, at 5. The PBL has said no more on the issue than that. Indeed, it would be inappropriate for PBL to do any more than that, in light of the functional separation of the business lines that BPA has undergone since the last rate case. As noted elsewhere, BPA is attempting to comply with the FERC restructuring orders by, among other things, adhering to FERC-approved Standards of Conduct and meeting comparability requirements under an open access transmission tariff. PBL will participate as a party in the transmission rate case and will be subject to the same *ex parte* restrictions as any other party. It would be inconsistent with these policies for PBL to make representations on behalf of TBL regarding the conduct and content of its rate case. *Id*.

Decision

BPA's method of removing identifiable transmission costs in the IP-83 Standard rate creates a reasonable parity between the floor rate and the unbundled IP-02 rate. In the interest of both fairness and accuracy, the floor rate test should be done for power only.

15.4 DSI Value of Reserves

Issue 1

Whether BPA should set a maximum rate for the DSI value of reserves credit for Supplemental Reserves under the IP-02 rate schedule equal to the cap on the inter-business line charge for operating reserves generation inputs.

Parties' Positions

No party addressed this issue in its initial brief.

BPA Position

BPA proposed a maximum rate for the DSI value of reserves credit for Supplemental Reserves under the IP-02 rate schedule equal to the cap on the inter-business line charge for operating reserves generation inputs.

Evaluation of Positions

Rate directives in the Northwest Power Act applicable to the DSIs require that the value of reserves credit be established in the rate case. 16 U.S.C. §839e(c)(3). Even though PBL is not presently forecasting purchases of Supplemental Reserves from the DSIs, PBL needs the flexibility to purchase Supplemental Reserves from the DSIs without initiating a separate section 7(i) process. McRae *et al*., WP-02-E-BPA-29, at 8. PBL proposed a flexible rate with a cap that will permit BPA to negotiate a price according to the quality of the reserves provided by the DSIs, if any. *Id.* at 4. The cap is equivalent to the cap on inter-business line charges for generation inputs for operating reserves. *Id.* at 6. Generation inputs for operating reserves have essentially the same electrical characteristics as the highest-quality Supplemental Reserves that PBL might purchase from the DSIs. *Id.* Thus, it is appropriate to cap the DSI Supplemental Reserves credit at the embedded cost price that PBL charges TBL for similar services. *Id.*

Decision

BPA will set a maximum rate for the DSI value of reserves credit for Supplemental Reserves under the IP-02 rate schedule equal to the cap on the inter-business line charge for operating reserves generation inputs.

Issue 2

Whether BPA should establish certain guidelines to help define the Supplemental Reserves PBL may purchase from the DSIs and to identify criteria relevant to the negotiated price PBL may pay for those reserves.

Parties' Positions

No party addressed this issue in its initial brief.

BPA's Position

BPA proposed certain guidelines to help define the Supplemental Reserves PBL may purchase from the DSIs and to identify criteria relevant to the negotiated price PBL may pay for those reserves. McRae *et al*., WP-02-E-BPA-29, at 6-7.

Evaluation of Positions

Supplemental Reserves include interruptible load. *Id.* at 2. PBL proposed a flexible rate with a cap that will permit BPA to negotiate a price according to the quality of the reserves provided by the DSIs, if any. *Id.* at 4. The suitability and quality of the Supplemental Reserves will be measured by whether they have certain characteristics, some of which are required and others optional. *Id.* at 6. Any Supplemental Reserves purchased by PBL must be consistent with current NERC, WSCC, NWPP, and other applicable reliability criteria, presently including, but not limited to, the following:

1. The interruptible load must be offline within 5 minutes after a call by BPA;

2. In the event of a system disturbance, the interruptible load must be accessible prior to a request for reserves from other NWPP parties; and

3. The interruptible load must be available to be offline for up to 60 minutes.

Id. In addition to these required characteristics, the issues identified below will help define when PBL may pay the maximum value for Supplemental Reserves:

1. The extent to which PBL has discretion over when and how to use all reserves and to determine what resources to call on in the event of a system disturbance; and

2. Whether there are limitations on the number of times or total minutes the reserves may be utilized.

Id. These criteria should provide BPA and the DSIs useful guidance in negotiating the price of any Supplemental Reserves PBL may wish to purchase from the DSIs.

Decision

BPA will establish the guidelines outlined above to help define the Supplemental Reserves PBL may purchase from the DSIs and to identify criteria relevant to the negotiated price PBL may pay for those reserves.

15.5 Compromise Approach

15.5.1 Introduction

On December 21, 1998, BPA issued the Power Subscription Strategy ROD. The Subscription Strategy ROD describes BPA's position on a number of issues, including the availability of Federal power post-2001, the approach BPA plans to use in selling power by contract with its customers, the products from which customers can choose, and frameworks for pricing and contracts. Subscription Strategy ROD, at 1.

In the Subscription Strategy ROD, BPA stated that it expected to meet DSI loads, but noted that the actual level of service to the DSIs was contingent on the availability of power remaining after the close of the Subscription window. 64 Fed. Reg. 44318, 44322. The Subscription Strategy ROD further stated that BPA was not prepared at the time of issuing the ROD to make a number of final decisions, including decisions regarding augmentation to serve DSI load. *Id.*

Subsequent to the Subscription Strategy ROD, but prior to the start of the rate proceeding, BPA met with the DSIs on several occasions to address some of the DSIs' service issues left unresolved in the Subscription Strategy ROD. Berwager *et al*., WP-02-E-BPA-38, at 2. BPA and the DSIs exchanged various service proposals, none of which was mutually acceptable. Ultimately, BPA, with help from the DSIs, crafted a proposal called the Compromise Approach.

The Compromise Approach proposal is dated June 17, 1999, and by its own terms, is "the approach that BPA would propose as part of the initial proposal for the upcoming rate case if the DSIs are willing to support it." Berwager *et al*., WP-02-E-BPA-09, Attachment 1, at 1 (Compromise Approach). The Compromise Approach includes a proposed rate and a proposed allocation of power for service to the DSIs. With respect to power allocation, the Compromise Approach provides that "1,500 MW of power will be made available to the DSIs," which "represents a large portion (three-fourths) of the load placed on BPA during the previous five years at a cost-based" rate. *Id*. at 2. With respect to price, the Compromise Approach proposal states that "the price for the 1,500 MW is $23.50 per MWh." *Id*.

The Compromise Approach proposal was received by the majority of the DSIs with appreciation and support. In a letter to BPA, the President of Goldendale Aluminum Co., and Northwest Aluminum Co., stated:

> I want to begin by expressing my thanks to Paul Norman, Syd Berwager and the rest of the BPA staff for their efforts to put together a compromise for BPA service to its Direct Service Industrial customers (DSIs).
>
> The attached June 14, 1999 "Compromise Approach" for BPA service to the DSIs during the period FY 2002-2006 is a major step by BPA to address concerns about our survivability in the PNW. While there still are several important open issues to be decided during the upcoming rate case, the Compromise Approach does provide a framework to meet the needs both of BPA and our company and employees. Our company will support the framework of the Compromise Approach in the rate case and other venues, and work with you to ensure that all open issues are resolved in such a way that the end result is something that woks for both our company and BPA.

Cross-Examination Exhibit, WP-02-E-AL-32, at 6, 8.

Similarly, Columbia Falls Aluminum Company (CFAC) stated that it:

> . . . very much appreciates BPA's efforts to develop a viable approach to providing power to CFAC and other DSI customers. The Compromise Approach dated June 14, 1999, does not answer all of the issues of concern to CFAC exactly as we would have preferred, but it does provide a solid basis for continuing our dialog in the rate case. It is the fruit of some very hard work by Paul Norman and his staff and we believe they have carefully listened to DSI concerns and have honestly created a good starting point. We urge you to include the Compromise Approach in the initial proposal for the upcoming power rate case.

Cross-Examination Exhibit, WP-02-E-AL-32, at 14.

A letter from Reynolds Aluminum is in accord, stating that the Compromise Approach proposal "is a step in the right direction, and a positive initial proposal for the upcoming rate case. Reynolds supports you moving forward with the rate case, and supports including this proposal for continuing cost-based service to Reynolds as part of BPA's initial rate case filing." Cross-Examination Exhibit, WP-02-E-AL-32, at 4.

Indeed, even Alcoa expressed its support, stating:

> Alcoa, and I personally, appreciate the effort that you and your staff have made attempting to craft a proposal that would meet Alcoa's needs as well as those of BPA and other stakeholders. While the compromise proposal retains the service and costs framework proposed by BPA, I recognize that significant progress has been made over the past few weeks towards that common goal.
>
> I believe that elements of BPA's approach have merit, and that our discussions have been productive. Alcoa does not see the need to cut discussions short in order to enter immediately into a formal rate case. However, if you believe you cannot delay the rate case, the Compromise Approach should be included in your initial rate proposal so it can evolve into a truly workable solution through that process.

Cross-Examination Exhibit, WP-02-E-AL-32, at 16.

Although the majority of the DSIs voiced clear support for the Compromise Approach proposal, the letters were not all uniform and identified various issues of concern. As such, BPA sent concurrence letters to the DSIs, with the Compromise Approach proposal attached. Berwager *et al.*, WP-02-E-BPA-09, Attachment 1, at 1 (prototype concurrence letter). In the concurrence letters, BPA stated:

> [R]ecent letters BPA received from the DSIs in support of BPA making this proposal varied greatly in their contents. The letters did not address, in a clear and consistent manner, issues that are important to BPA in making this important decision. This letter is intended to create the clarity necessary for BPA to decide that BPA has the support necessary to move forward with the Compromise Approach proposal in the rate case initial proposal. Without concurrence by the DSIs on the following issues, BPA will not be able to move forward with that proposal. Instead, the initial proposal will have to reflect an earlier proposal (the so-called Targeted Augmentation Approach) BPA placed before the DSIs on April 26, 1999.

Id.

BPA requested, among other things, that DSIs accepting the Compromise Approach proposal not challenge that proposal in the rate case and not litigate the Compromise Approach proposal if it were ultimately adopted in BPA's final ROD. Berwager *et al*., WP-02-E-BPA-09, Attachment 1.

BPA received signed concurrence letters from the majority of the DSIs. However, two DSIs, Alcoa and Vanalco, declined to accept the Compromise Approach proposal. Alcoa and Vanalco stated that they remained dissatisfied with the proposed price and allocation of power contained in the Compromise Approach proposal, and wanted to retain all rights to challenge BPA's proposal in the rate case and in any other forum. Speer *et al*., WP-02-E-AL/VN/EG-01, Attachments 2 and 3.

Given that Alcoa and Vanalco rejected the Compromise Approach, BPA considered withdrawing the proposal. Berwager *et al*., WP-02-E-BPA-38, at 2. However, BPA decided that withdrawing the proposal could have considerable adverse consequences to the DSIs that elected to accept the Compromise Approach. As stated in BPA's initial testimony:

> While BPA did consider taking the Compromise Approach off the table in light of the fact that two DSIs elected not to sign the agreement, BPA felt that doing so would defeat its objective of supporting continued DSI operations and employment in the region, consistent with its many other rate case goals. BPA believed also that it would be appropriate to move forward with the proposal on behalf of the DSIs who had said they accepted it as part of the initial proposal and would be willing to support it.

Id.

As a result, in the Federal Register Notice announcing the rate case, BPA stated that the Compromise Approach proposal would be included in BPA's initial proposal and subject to review and scrutiny in the rate case. As stated therein,

> BPA does not intend to conduct a separate public process to take comments on this [Compromise Approach] proposal. Therefore, parties to the rate case may raise and discuss any issues regarding BPA's proposal to serve the DSIs including any issues regarding the potential effects of this proposal on BPA's rates.

64 Fed. Reg. 44322.

In addition, because Alcoa and Vanalco rejected the Compromise Approach proposal, BPA was left with a choice of either proposing not to serve these two DSIs at all, or serving them under the terms contained in the proposal to the DSIs that preceded the Compromise Approach proposal, the so-called Targeted Augmentation Approach. Berwager *et al*., WP-02-E-BPA-38, at 3. BPA elected the latter approach. Pursuant to the Targeted Augmentation Approach, BPA proposed to offer up to 230 aMW to these two customers at a rate of 25.0 mills/kWh. *Id*.;

Berwager *et al.*, WP-02-E-BPA-09, at 2. BPA's reasons for proposing service to Alcoa and Vanalco under the Targeted Augmentation Approach are discussed in section 15.5.4, *infra*.

As a result, BPA's proposal for service to the DSIs was described in BPA's initial testimony as follows:

> BPA has developed what is called the 'Compromise Approach' for service to the DSIs. Under this approach, BPA is proposing to offer the DSIs up to 1,440 aMW in the form of a firm power block product. This power will be allocated among the DSIs based on each DSIs purchases under the current Industrial Firm Power (IP-96) rate, and will be sold under the IP Targeted Adjustment Charge (IPTAC) rates. For some of these DSIs, BPA is proposing an IPTAC rate of 23.5 mills/kWh for a flat block of power that is about 75 percent of what they are currently buying. BPA expects to sell 1,210 aMW to these customers. For other DSIs [Alcoa and Vanalco] that are currently buying power under the IP-96 rate, BPA is proposing an IPTAC rate of 25.0 mills/kWh for a flat block of power that is about 60 percent of what they are currently buying. Under the proposal, these customers would be eligible to purchase up to 230 aMW, but there is some uncertainty regarding how much of this amount will be purchased.

Id.

Alcoa and Vanalco have expressed continuing dissatisfaction with the Compromise Approach proposal, as well as BPA's proposal in this rate proceeding, to serve them with up to 230 aMW at 25.0 mills/kWh. They filed lawsuits in Federal court to enjoin the rate case, implementation of the Compromise Approach proposal, and the Subscription Strategy ROD. Their cases were dismissed for lack of jurisdiction. *See Alcoa, Inc. et al. v. Bonneville Power Administration*, Nos. 99-71188 & 99-71189 (dismissal order filed February 9, 2000); *Goldendale Aluminum Co. et al. v. Bonneville Power Administration*, Nos. 99-70268 *et seq*. (dismissal order filed February 9, 2000); *Vanalco Inc. et al. v. Bonneville Power Administration*, No. 99-36213 & 00-35009 (dismissal order filed February 9, 2000, noting that "the questions raised in these appeals are so insubstantial as not to need further argument."). Alcoa and Vanalco have raised a number of constitutional and statutory objections to the Compromise Approach proposal. Each of these objections is discussed below.

15.5.2 <u>Constitutional Issues</u>

<u>Issue 1</u>

Whether the Compromise Approach unlawfully infringes on Alcoa's and Vanalco's First Amendment rights to petition the government for a redress of grievances.

Parties' Positions

Alcoa and Vanalco allege the Compromise Approach violates the Petition Clause of the First Amendment to the U.S. Constitution. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 5. According to Alcoa and Vanalco:

> [T]he Petition Clause guarantees Alcoa's and Vanalco's right to make their views known to the BPA on the general subject of BPA's proposed rate-making proposals. BPA's Compromise Agreement unconstitutionally burdens the exercise of this right. Alcoa and Vanalco must pay (or are threatened with paying) a higher rate and receive (or are threatened with receiving) a smaller allocation of power than the companies who succumbed to the Compromise Agreement.

Id. at 6.

The case most heavily relied on by Alcoa and Vanalco in their initial brief in support of their argument is *Acevedo v. Surles*, 778 F. Supp. 179 (SDNY 1991). Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 6-7. According to Alcoa and Vanalco, the Compromise Approach, similar to the agency practice at issue in *Acevedo*, "had the effect of chilling" their First Amendment rights by imposing a "surcharge" for exercising those rights. *Id*.

Further, in their initial brief, Alcoa and Vanalco contend that:

> [T]he Compromise Agreement conditions a benefit upon relinquishment of First Amendment rights. In exchange for preferential power and rates treatment, the Compromisers have agreed to content restrictions on their speech and to not fully participate in the rate-making process, including judicial review, as they otherwise would. Unquestionably the preferential treatment is a benefit, and its quid pro quo a relinquishment of First Amendment rights. The Compromisers consent to the relinquishment of First Amendment rights does not cure the First Amendment violation . . . The Compromise Agreements subvert the congressionally mandated public process. Indeed, silencing the DSIs is precisely BPA's intent, although BPA may choose different words of description.

Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 7-8.

In their brief on exceptions, Alcoa and Vanalco continue the same line of argument, asserting that BPA violated their First Amendment rights "to participate in this rate case on all issues, without being penalized through the smaller allocation and higher rates they suffer for refusing the silence required by the Compromise Approach." Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 47. Moreover, they downplay the significance of *Acevedo v. Surles*, *supra*, stating that it is simply "a single district court decision." *Id*. at 51. Instead, they state that their case rests on more "well known jurisprudence" established in numerous cases by the U.S. Supreme Court. *Id*.

BPA's Position

Given the strictly legal nature of Alcoa's constitutional arguments, BPA witnesses did not address this issue of whether the Compromise Approach infringed on Alcoa's and Vanalco's First Amendment rights.

Evaluation of Positions

BPA strongly disagrees with Alcoa's and Vanalco's arguments and conclusions. BPA believes that *Acevedo v. Surles*, as well as the Supreme Court cases cited by Alcoa and Vanalco, are inapposite. Indeed, *Acevedo* provides an illuminating example of a meritorious First Amendment claim as opposed to the kind of claims raised by Alcoa and Vanalco.

In *Acevedo*, indigent hospital patients faced the prospect of losing medical benefits for necessary hospital care if they filed a claim, in court, against the state hospital that provided the care. The Court noted that "after a patient files a claim against the State in the New York Court of Claims, the [hospital] will serve a verified claim against the patient in which the patient is assessed full charges for the hospitalization and treatment received." 778 F. Supp. at 182. As a consequence, a patient filing a claim for approximately $2,000 could be met with a counterclaim by the hospital exceeding $100,000. *Id*. at 185. The Court found this penalty "chilled" the plaintiff's First Amendment rights to seek redress in the courts. Rather than supporting Alcoa's argument, *Acevedo* provides a striking contrast.

First, and perhaps most importantly, neither Vanalco nor Alcoa is a signatory to the Compromise Approach proposal. As such, they are not restricted in any manner by the Compromise Approach from pursuing relief in any forum (with jurisdiction) against BPA. None of their First Amendment rights to petition the government has been impacted by the Compromise Approach proposal. In contrast, the First Amendment rights of the indigent hospital patients were directly at issue in *Acevedo*.

Second, the indigent hospital patients in *Acevedo* did not have a full evidentiary administrative forum, presided over by a hearing officer, available to them to argue against the imposition of any penalty or charge. In fact, they had virtually no forum available to them at all. In this case, Alcoa and Vanalco had every opportunity to present their case in the ongoing rate case prior to any "penalty" being adopted, assessed, or imposed.

Third, the Compromise Approach proposal was a proposal arrived at voluntarily. The DSIs that elected to participate in the Compromise Approach proposal did so because it was presumably in their business interests to do so. Alcoa and Vanalco elected to opt out. That was their choice. No such choice was available to the plaintiffs in *Acevedo*.

Fourth, there was no penalty imposed or assessed against Alcoa and Vanalco under the Compromise Approach. Any differences in the terms or conditions of service that may exist between the DSIs that signed the Compromise Approach, as opposed to those that did not (Alcoa and Vanalco), is based on and justified by testimony filed by BPA in the instant rate proceeding. Indeed, as demonstrated in BPA's testimony, BPA is offering to sell Alcoa and

Vanalco more than half of the power they are currently purchasing from BPA at a price of 25 mills/kWh, well below projected market power prices. Berwager *et al*., WP-02-E-BPA-38, at 3; *see* ROD section 15.5.4, infra.

Fifth, post-2001, none of the DSIs, including Vanalco and Alcoa, has a statutory right to purchase power from BPA. Although BPA may elect to serve the DSIs, BPA is not obligated to do so. In section 5(g) of the Northwest Power Act, Congress required BPA, in 1981, to offer the DSIs 20-year power sales contracts. 16 U.S.C. §839e(g)(1). Once those contracts expire, BPA has the authority, but not the obligation, to offer the DSIs new power sales contracts. This issue is discussed more fully at section 15.5.3, *infra*. Accordingly, Vanalco and Alcoa have no right to any particular allocation of BPA power or any allocation at a particular price. In contrast, the indigent hospital patients in *Acevedo* had a right to subsidized medical treatment.

Sixth, the instant case involves commercial transactions with sophisticated purchasers. Indeed, Alcoa is one of the largest multinational aluminum companies in the world. Vanalco and Alcoa have extensive resources at their disposal and the ability to make fully informed decisions with the support of the best attorneys, consultants, and experts available. The indigent hospital patients in *Acevedo* were hardly in a similar position.

The bottom line is that *Acevedo* provides no support for Alcoa's and Vanalco's allegations that their First Amendment rights to petition the government have been violated. Other cases cited by Alcoa and Vanalco are equally deficient and readily distinguishable. For instance, in their brief on exceptions, Alcoa and Vanalco quote passages from various cases from the U.S. Supreme Court. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 47-51. For the most part, the quoted portions of these cases simply recite black letter law regarding the importance and sanctity of the First Amendment. No one disagrees with these fundamental tenets. However, Alcoa and Vanalco fail to provide any nexus between the facts and holdings of those cases and the facts of this case. Moreover, none of these cases involves entities such as Alcoa and Vanalco attempting to assert First Amendment rights of behalf of an unaffiliated third party, especially where that third party is a competitor in business.

A case in point is *Eastern R. Pres. Conf. v. Noerr Motor Freight, Inc*., which Alcoa and Vanalco describe as "[t]he leading Supreme Court case, and one of the few descriptive of the right of petition." Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 47. Alcoa and Vanalco state that *Noerr* "asserts the principle that guides one here: '[t]he right of petition is one of the freedoms protected by the Bill of Rights, and we cannot, of course, lightly impute to Congress an intent to invade these freedoms.'" *Id*. at 48. No one disagrees. The point, however, is that *Noerr* involved the scope of the Sherman Antitrust Act and whether Congress intended to prohibit certain political activity, as opposed to business activity, through that law. The Supreme Court refused to "lightly impute" to Congress an intent to restrict First Amendment political activity. The instant case has nothing to do with an interpretation of the Sherman Act or imputing any intent to Congress under any other statute.

Alcoa and Vanalco argue that "[t]his matter is also controlled by *Board of City Comm'rs v. Umbehr*," which they contend "clearly rejects 'unconstitutional conditions on speech.'" Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 50. That argument, of course, assumes the precise issue in dispute. Nevertheless, the issue before the Court in *Umbehr* was "whether, and to what extent, independent contractors are protected by the First Amendment," and in particular "whether, and to what extent, the First Amendment restricts the freedom of federal, state or local governments to terminate their relationships with independent contractors because of the contractors' speech." 518 U.S. at 673, 673-74. The instant case, of course, involves nothing of the kind. It involves voluntary decisions by parties other than Alcoa and Vanalco to agree to a preliminary proposal for purposes of an administrative hearing.

Moreover, the fact that Alcoa and Vanalco have suffered no restrictions on their right to petition the government is highlighted by their own arguments. Attached to their brief on exceptions is testimony filed by Alcoa before Congress on April 6, 2000. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, Ex. A, at 7-12. In that testimony, Mr. Jack Speer, Northwest Energy Leader for Alcoa, addressed a U.S. House of Representatives Subcommittee on Water and Power. *Id*. The subject of the hearing was BPA's Subscription process. *Id*. at 5. In his testimony, Mr. Speer advised Congress of Alcoa's views on BPA's proposal for service to the DSIs as well as his views on BPA's proposed service to other BPA customers. *Id*. at 7-12. Indeed, Mr. Speer's testimony addresses many of the same issues Alcoa and Vanalco complain of in this rate proceeding, including reduced service to the DSIs. *Id.* at 7-8 ("[w]here Bonneville used to supply about 95 percent of Northwest aluminum load, it is now offering to supply only 40-50 percent of the industry's needs, and some of that power will be priced at market rates instead of traditional rates based on the cost of federal generation resources"). As such, Alcoa's and Vanalco's brief contradicts their own argument that their First Amendment rights to petition the government have been impaired by the Compromise Approach.

Lastly, Alcoa and Vanalco argue that "the Compromise Agreements subvert the congressionally mandated public process. Indeed, silencing the DSIs is precisely BPA's intent . . ." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 8. Contrary to this allegation, and as demonstrated above, it is clear that Alcoa and Vanalco have not been "silenced" in any manner. Moreover, the DSIs that signed the Compromise Approach proposal, as well as Alcoa and Vanalco, actively participated in the rates hearing through the presentation of a huge volume of testimony on a wide variety of issues. *See e.g.,* Schoenbeck *et al*., WP-02-E-DS/AL/VN-01; Schoenbeck *et al*., WP-02-E-DS/AL/VN-02; Schoenbeck *et al*., WP-02-E-DS/AL/VN-03; Schoenbeck *et al*., WP-02-E-DS/AL/VN-04; WP-02-DS/AL/VN-05; Schoenbeck *et al*., WP-02-E-DS/AL/VN-06; Adams, WP-02-E-DS-01; Wilcox *et al*., WP-02-E-DS-02; Schoenbeck *et al*., WP-02-E-DS-03; Adams, WP-02-E-DS-04; Waddington, WP-02-E-DS-05; Schoenbeck *et al*., WP-02-E-DS-06.

Indeed, much of the testimony submitted by the "Compromising DSIs" was submitted as joint testimony with Alcoa and Vanalco. *See e.g*., Schoenbeck *et al*., WP-02-E-DS/AL/VN-01; Schoenbeck *et al*., WP-02-E-DS/AL/VN-02; Schoenbeck *et al*., WP-02-E-DS/AL/VN-03; Schoenbeck *et al*., WP-2-DS/AL/VN-04; WP-02-E-DS/AL/VN-05; Schoenbeck *et al*., WP-02-E-DS/AL/VN-06. As noted in BPA's testimony, "[i]t is not true that the DSIs are foreclosed by the Compromise Agreement from further discussion of DSI issues. This should be abundantly clear from the volume of testimony on DSI issues filed by the DSIs that did sign the Compromise Approach." Berwager *et al*., WP-02-E-BPA-38, at 9.

It may be that Alcoa and Vanalco believe "the Compromise Approach atomized the DSIs, marginalized Alcoa and Vanalco, and interrupted the historical unity of the DSIs." Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 54, n. 2. And, it may be that Alcoa and Vanalco believe they lost political and legal clout as a consequence of the Compromise Approach proposal. However, if the "historical unity" of the DSIs was as intact as Alcoa and Vanalco claim, then presumably all the DSIs would have accepted or rejected the Compromise Approach proposal. The fact that most accepted, while Alcoa and Vanalco did not, indicates the alleged unity was already fractured.

From BPA's perspective, the Compromise Approach was a good faith effort to reduce contention and litigation in the rate proceeding by developing an initial rate proposal that had support from the customers most directly affected by it--the DSIs. It evolved out of a series of meetings with the DSIs and was widely endorsed by the DSIs, including Alcoa, as an improvement over alternative DSI service proposals. *See, supra*, section 15.5.1. There is nothing in section 7(i) of the Northwest Power Act suggesting that a BPA rate proceeding must necessarily be divisive, litigious, and acrimonious. BPA does not believe it "subverts" the section 7(i) process or the First Amendment by attempting to reduce contention rather than enhance it.

<u>Decision</u>

BPA has not violated the First Amendment rights of Alcoa and Vanalco to petition the government for a redress of grievances.

<u>Issue 2</u>

Whether the Compromise Approach violates Alcoa's and Vanalco's First Amendment rights of assembly.

<u>Parties' Position</u>

Alcoa and Vanalco argue that their First Amendment rights to assemble with other DSIs have been violated by the Compromise Approach. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 8. According to Vanalco and Alcoa, "the Assembly Clause protects the rights of persons to join together to seek favorable action from an administrative agency." *Id*. In their initial brief, Alcoa and Vanalco allege that:

> [T]he Compromisers, of course, have no constitutional obligation to assemble with Alcoa and Vanalco to petition BPA. They may not, however, choose not to associate as part of an agreement with BPA which itself violates the First Amendment. Based on their traditional positions, the Compromisers would likely be joining in with Alcoa and Vanalco on many issues that they have been silent about in their rate case testimony.

Id.

In their brief on exceptions, Alcoa and Vanalco expand on this point, arguing that their First Amendment rights include the rights to lobby Congress and participate in the rate case "as a cohesive group with all DSIs." Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 47. They further contend that *their* rights include the rights "of the Compromise DSIs to speak freely on all rate case issues, in the courts, and before Congress." *Id*. Alcoa and Vanalco state that "the Compromise Approach violates the First Amendment speech and assembly rights of the Compromise DSIs and that Alcoa and Vanalco have standing to assert these rights." Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 56; *id*. at 54.

<u>BPA's Position</u>

Given the strictly legal nature of Alcoa's constitutional arguments, BPA witnesses did not address this issue of whether the Compromise Approach infringed on Alcoa's and Vanalco's First Amendment rights of assembly.

<u>Evaluation of Positions</u>

The Compromise Approach says nothing about the DSIs associating, or not associating, with one another. Each DSI is free to assemble with whomever it chooses. By agreeing to the Compromise Approach proposal, the "Compromising DSIs" elected not to challenge certain aspects of BPA's rate proposal. That was their choice and their prerogative. Alcoa and Vanalco, in contrast, elected to reject the Compromise Approach and challenge every aspect of BPA's rate proposal in every available forum. That is their choice and their prerogative. As a result, the "Compromising DSIs" and the "non-Compromising DSIs" made different business decisions with different consequences. The fact that these parties may have some differing interests and may elect to "associate" with each other on some issues but not "associate" on others, hardly rises to a constitutional level. Indeed, as noted above, Alcoa and Vanalco "associated" with the "Compromising DSIs" by sponsoring joint testimony on a wide spectrum of rate case issues. *See e.g.*, Adams, WP-02-E-DS-01; Wilcox and Waddington, WP-02-E-DS-02; Schoenbeck and Bliven, WP-02-E-DS-03; Adams, WP-02-E-DS-04; Waddington, WP-02-E-DS-05; Schoenbeck *et al*., WP-02-E-DS/AL/VN-01; Schoenbeck *et al*., WP-02-E-DS/AL/VN-02; Schoenbeck *et al*., WP-02-E-DS/AL/VN-03; Schoenbeck *et al*., WP-02-E-DS/AL/VN-04; WP-02-E-DS/AL/VN-05; Schoenbeck *et al*., WP-02-E-DS/AL/VN-06.

In their brief on exceptions, Alcoa and Vanalco expressly state that they have standing to assert the First Amendment rights of the DSIs that signed the Compromise Approach proposal. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 54, 56. Alcoa and Vanalco fail to cite any authority that supports this proposition. Rather, they simply say "[s]ee the response to Section 15.5.1." *Id*. However, Alcoa and Vanalco do not appear to make a standing argument in that section of their brief. The only case in that section that appears to directly address the issue of standing and the First Amendment is *NAACP v. Alabama*, 357 U.S. 449 (1958). *Id*. at 48. That case, however, is wholly distinguishable.

The issue in *NAACP* was whether the courts of Alabama properly held the NAACP in contempt of court for refusing to fully disclose the names of its members. Disclosure of the identity of NAACP members would have had severe repercussions on those individuals, including "economic reprisal, loss of employment, [and] the threat of physical coercion." 357 U.S. at 462. The NAACP asserted its right and standing to act on behalf of its members, and the Supreme Court agreed. 357 U.S. at 458. The Court stated that:

> The Association [NAACP] both urges that it is constitutionally entitled to resist official inquiry into its membership lists, and that it may assert on behalf of its members, a right personal to them to be protected from compelled disclosure by the State of their affiliation with the Association as revealed by the membership lists. We think that petitioner argues more appropriately the rights of its members, and that its nexus with them is sufficient to permit that it act as their representative before this Court. In so concluding, we reject respondent's argument that the Association lacks standing to assert here constitutional rights pertaining to the members, who are not of course parties to the litigation.

Id. at 458-459.

If *NAACP* is the basis for Alcoa's and Vanalco's standing argument, their argument is frivolous. The legal and factual distinctions between *NAACP* and the instant case are striking. Suffice it to say that Alcoa and Vanalco are not representatives of any other DSIs and have no rights to act on behalf of any other DSIs.

Moreover, contrary to Alcoa's and Vanalco's arguments, the Supreme Court stated in *NAACP* that it "has generally insisted that parties rely only on constitutional rights *which are personal to themselves*." *Id*. at 459 (emphasis added). Alcoa's and Vanalco's argument that it has standing to assert constitutional rights of the "Compromising DSIs" squarely contradicts this rule.

Alcoa and Vanalco attempt to portray all the DSIs as a single homogenous group. That portrayal is false. Contrary to their representation, many of the DSIs directly compete against one another. As a result, Alcoa appears to be using the First Amendment as a vehicle to challenge an agreement voluntarily entered into by its competitors, and to contend that it has standing to do so. There is no First Amendment law cited by Alcoa and Vanalco to support this kind of practice. On the contrary, the only law cited by Alcoa and Vanalco rejects their argument.

Similarly, Alcoa and Vanalco argue that, "based on their traditional positions the Compromisers would likely be joining in with Alcoa and Vanalco on many issues they have been silent about in their rate case testimony." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 8. This argument is highly speculative. Given the era of energy deregulation, traditional alliances have undergone considerable change. The very fact that the "Compromising DSIs" accepted the Compromise Approach proposal, whereas Vanalco and Alcoa did not, demonstrates that a divergence of interests already exists between these various DSIs.

For instance, under the Compromise Approach proposal, the amount of power each DSI would be allocated is based on the amount of cost-based IP purchases made by each DSI in FY 1997-2001. Berwager *et al*., WP-02-E-BPA-09, Attachment 1, at 1. Those DSIs that purchased larger amounts of IP power from BPA during this time period, such as Reynolds Metals, would be entitled to larger amounts of IP power under the Compromise Approach proposal than those DSIs that purchased smaller amounts of IP power. As a result, in a letter to BPA, Reynolds Metals stated it would support the Compromise Approach "*provided* the power is allocated among the DSIs in the manner proposed by BPA." Cross-Examination Exhibit, WP-02-E-AL-32, at 3 (emphasis in original).

In contrast, Alcoa and Vanalco purchased relatively small amounts of IP power from BPA in FY 1997-2000. In a letter to BPA, Vanalco expressed dismay that under the Compromise Approach proposal, it would be eligible to purchase only "an amount of power between 0 and 7.5 average megawatts out of its total plant load of 235 megawatts." Cross-Examination Exhibit, WP-02-E-AL-32, at 10. The reason is that, in 1996, Vanalco elected to reduce the amount of IP power it purchased from BPA under its power sales contract from 230 aMW to 10 aMW to purchase power from suppliers at market prices which, at the time, were generally below BPA's cost based rates. *See, generally, Association of Public Agency Customers et al. v. Bonneville Power Administration*, 126 F. 3d 1158, 1176 (9th Cir. 1997) ("By the fall of 1995, competition for the DSIs' business was fierce. Many were considering attractive offers from alternative suppliers to serve their loads at prices below BPA's rates."). Similarly, Alcoa was not satisfied with the allocation provision of the Compromise Approach proposal and noted that there "should be further discussion of the allocation method among companies." *Id*. at 16.

During the course of the section 7(i) hearing, Alcoa and Vanalco have been able to fully and completely litigate their case, individually, in concert with each other, and in concert with the other DSIs. Neither the Northwest Power Act nor the First Amendment of the U.S. Constitution entitles them to any more.

Decision

Alcoa's and Vanalco's argument that their First Amendment rights to assembly have been violated by the Compromise Approach is without merit.

Issue 3

Whether "the Subscription ROD-Compromise Approach scheme" violates Alcoa's and Vanalco's rights to equal protection under the law.

Parties' Position

Alcoa and Vanalco allege that "[t]hrough the Subscription ROD-Compromise Approach scheme, BPA has denied Alcoa and Vanalco equal protection under the laws. With no legitimate justification, BPA has offered lower power rates and a larger allocation of power to the DSIs who have submitted to the Subscription ROD-Compromise Approach scheme, than to those who have insisted upon asserting their rights to participate fully in the power rate case, namely Alcoa and Vanalco." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 8-9. Alcoa and Vanalco reiterate this argument in their brief on exceptions. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 56-57.

BPA's Position

Given the strictly legal nature of Alcoa's constitutional arguments, BPA witnesses did not address this issue of whether the Compromise Approach infringed on Alcoa's and Vanalco's equal protection rights.

Evaluation of Positions

Alcoa and Vanalco offer no explanation of how their allegations translate into an equal protection issue. If their claim is that BPA failed to justify the proposed rate disparity between the DSIs that executed the Compromise Approach and those that did not (Alcoa and Vanalco), that justification is set forth in section 15.5.4, *infra*. Alcoa and Vanalco offer no support for their argument that a proposed rate disparity rises to the level of an equal protection violation.

Alcoa and Vanalco claim that BPA proposed a more "onerous" service arrangement upon them as opposed to the "Compromising DSIs" because they refused to accede to the Compromise Approach. Speer *et al*., WP-02-E-AL/VN/EG-01, at 4. BPA witnesses contradicted this allegation, stating:

> [W]e disagree with Alcoa's and Vanalco's characterization of BPA's proposal for service to them as 'onerous.' BPA is offering to sell Alcoa and Vanalco more than half of the power they are currently purchasing from BPA at a price of 25 mills/kilowatt-hour (kWh), well below projected market power prices. *See* Oliver *et al*., WP-02-E-BPA-45. Second, Alcoa and Vanalco represented to BPA in negotiations that they were not interested in BPA power at either 23.5 or 25 mills/kWh, with or without the condition under the Compromise Approach, so it is unclear how the one proposal is 'onerous' compared to the other. Third, when Alcoa and Vanalco refused to join the other DSIs in signing the Compromise Approach, BPA could have opted to offer nothing to those two companies, or leave the original offer of their share of 1,200 average megawatts (aMW) at 25 mills/kWh on the table. In an attempt to demonstrate that there was no intent to unduly disadvantage Alcoa and Vanalco for their decision, BPA decided to carry the earlier below-market proposal to them into the initial proposal, so again we do not agree that proposing to make available to these two companies the original offer is 'onerous' compared with the alternative.

Berwager *et al.*, WP-02-E-BPA-38, at 3-4.

Lastly, Alcoa's and Vanalco's reference to a "Subscription ROD-Compromise Approach scheme" distorts and mischaracterizes BPA's actions. There was never a "scheme" to do anything. Rather, in the Subscription Strategy ROD, BPA stated that it expected to serve the entire DSI load. Months later, it was becoming less probable that such service could be provided. As noted in BPA's testimony:

> The Subscription Strategy committed no specific amount of service to the DSIs. It stated that BPA's expectation was to serve all DSI loads that individual

> companies asked BPA to meet. At the time the Subscription Strategy was developed, BPA expected to have sufficient inventory to meet DSI loads even after meeting other customer's [sic] Subscription requests with higher priority than DSI requests. Such an outcome now seems improbable given the high level of load projected to be placed on BPA by other customers.

Berwager *et al.*, WP-02-E-BPA-09, at 5-6.

In the Compromise Approach proposal, BPA, in cooperation with the DSIs, developed a proposal for service to the DSIs which included a proposed rate and proposed power allocation. Under this proposal, the DSIs would be eligible to receive "a flat block of power that is about 75 percent of what they are currently buying" at a rate of 23.5 mills/kWh, which is well below prevailing market rates. Berwager *et al.*, WP-02-E-BPA-09, at 2. This proposal was well received by the majority of DSIs, including Alcoa. Cross-Examination Exhibit, WP-02-E-AL-32, at 16. Indeed, correspondence from the "Compromising DSIs" reflects their support for and appreciation of the Compromise Approach proposal. *See* section 15.5.1, *supra*.

As a result, contrary to Alcoa's and Vanalco's allegations, the Compromise Approach is viewed by BPA as a favorable and generous proposal for service to the DSIs. This is especially true given that BPA and many customers and constituents in the region believe the sale of power to the DSIs post-2001 is purely discretionary. *See infra*, at 15.5.3. BPA has made a dedicated effort in the Compromise Approach proposal and in this rate proceeding to address an issue that was left unresolved at the time the Subscription Strategy ROD was issued, and to craft a proposal that was favorable to the DSIs without imposing undue costs on other BPA customers.

Decision

Alcoa's and Vanalco's claims that they have been deprived of equal protection under the law are without merit.

Issue 4

Whether Alcoa and Vanalco have been deprived of due process of law through the "Subscription ROD-Compromise Approach scheme."

Parties' Positions

Alcoa and Vanalco allege that "[t]hrough the Subscription ROD-Compromise Approach scheme, BPA has denied Alcoa and Vanalco due process of law" because: (1) they have been "denied their right under section 7(i) to a full rate hearing that permits all DSIs to fully participate"; (2) "Alcoa and Vanalco have been denied their right to have power within the class of DSIs to be equitably allocated . . ."; and (3) "the distinctions in power rates and power allocations between companies who submitted to the scheme and those who have not (Alcoa and Vanalco) are arbitrary, capricious, and an abuse of discretion which also violates §7(i) and the Administrative Procedures Act. . . ." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 9. Alcoa and Vanalco reiterate these arguments in their brief on exceptions. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 58-59.

BPA's Position

Given the strictly legal nature of Alcoa's constitutional arguments, BPA witnesses did not address the issue of whether the Compromise Approach infringed on Alcoa's and Vanalco's rights to due process.

Evaluation of Positions

Alcoa and Vanalco contend that they have been deprived of their rights to a full rate hearing that permits all DSIs to fully participate. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 9. Section 7(i) of the Northwest Power Act does not impose a minimum standard of participation on any DSI or on any other party. Each party to a BPA rate proceeding has the right to make its own determination regarding the level of its participation. A party can fully participate, partially participate, or not participate at all.

As noted *supra*, the DSIs that signed the Compromise Approach proposal actively participated in the rates hearing through the presentation of a huge volume of testimony on a wide variety of issues. *See* Schoenbeck *et al*., WP-02-E-DS/AL/VN-01; Schoenbeck *et al*., WP-02-E-DS/AL/VN-02; Schoenbeck *et al*., WP-02-E-DS/AL/VN-03; Schoenbeck *et al*., WP-02-E-DS/AL/VN-04; WP-02-DS/AL/VN-05; Schoenbeck *et al*., WP-02-E-DS/AL/VN-06; Adams, WP-02-E-DS-01; Wilcox *et al*., WP-02-E-DS-02; Schoenbeck *et al*., WP-02-E-DS-03; Adams, WP-02-E-DS-04; Waddington, WP-02-E-DS-05; Schoenbeck *et al*., WP-02-E-DS-06. Indeed, much of the testimony submitted by Alcoa and Vanalco was submitted jointly with the "Compromising DSIs." *See* Schoenbeck *et al*., WP-02-E-DS/AL/VN-01; Schoenbeck *et al*., WP-02-E-DS/AL/VN-02; Schoenbeck *et al*., WP-02-E-DS/AL/VN-03; Schoenbeck *et al*., WP-2-DS/AL/VN-04; WP-02-E-DS/AL/VN-05; Schoenbeck *et al*., WP-02-E-DS/AL/VN-06.

The fact that the "Compromising DSIs" did not challenge the Compromise Approach proposal is inconsequential. They simply elected to address issues which they found objectionable, and not address issues that were not objectionable. The "Compromising DSIs" determined at the outset of the proceeding that the Compromise Approach proposal was favorable and therefore not objectionable. Indeed, the Compromise Approach proposal was a proposal they helped develop and uniformly endorsed. "Those DSIs that agreed to the Compromise Approach did so partly on the basis that the service offered was an acceptable improvement, both in terms of price and amount, over what BPA had stated it was willing to offer them absent their agreement." Berwager *et al*., WP-02-E-BPA-38, at 5-6. There is no impropriety to this approach, and certainly nothing which offends due process.

Alcoa's other issues are addressed in other sections of this ROD. In particular, the issues of whether power has been "equitably allocated" within the class of DSIs, and whether BPA's distinctions in power rates and allocations are arbitrary, can be found in sections 15.5.4 and 15.5.5, *infra*.

Decision

Alcoa's and Vanalco's claims that they have been denied due process of law are rejected.

Issue 5

Whether the Compromise Approach violates the integrity of the section 7(i) process.

Parties' Positions

Alcoa and Vanalco assert that the Compromise Approach violates "the integrity of the section §7(i) process." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 10. They allege that BPA, through the Compromise Approach, has violated the section 7(i) requirements to develop a "full and complete record," and to provide "an adequate opportunity for any person 'to offer refutation or rebuttal of any material submitted by any other person or by the Administrator.'" *Id*. at 10-11. In their initial brief, Alcoa and Vanalco state that, while they "remain 'free' to rebut the Administrator's proposal, the Compromise Agreement silences those DSIs that accepted it on important rate case issues." *Id*. at 11.

In their brief on exceptions, Alcoa and Vanalco reiterate many of these arguments. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 59-63. They argue, among other things, that "[i]f a party is not afforded a right to rebut BPA's direct case, then the rebuttal record will not be 'full and complete' as required by §7(i)." *Id*. at 61. They further argue that "[b]y reason of the Compromise Approach, the Compromise DSIs had no opportunity to rebut BPA's proposed decision." *Id*.

In addition, Alcoa and Vanalco allege at numerous times that BPA prejudged the outcome of the rate case. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 2, 61-63, 111. In its initial brief, Alcoa and Vanalco allege "BPA effectively has decided in the Compromise Agreement several important factual issues, including the total amount of firm power available to the DSIs, the basis for allocating cost based power among the DSIs, the relative percentages of cost based power and market based power available to DSIs acquiescing to the Compromise Agreement." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 11. In their brief on exceptions, Alcoa and Vanalco state "the §7(i) process has been violated because the Administrator conducted this rate case with a closed mind." Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 61. Alcoa and Vanalco allege that BPA decided factual issues related to the Compromise Approach prior to the rate case and outside the scope of the section 7(i) process. *Id*. at 2, 62-63.

BPA's Position

The arguments by Alcoa and Vanalco that BPA violated section 7(i) are substantially the same as their arguments that BPA infringed on their constitutional rights to petition the government for redress, rights to assembly, rights to equal protection, and rights to due process of law. It is for these reasons that Alcoa and Vanalco contend that the integrity of the section 7(i) process has been violated.

BPA witnesses expressly contradicted allegations by Alcoa and Vanalco that were specifically directed towards questioning the integrity of the section 7(i) process. For example, in response to allegations by Alcoa and Vanalco that, through the Compromise Approach, BPA made a "final decision" regarding rates for service to the DSIs, BPA witnesses stated that "no final decisions regarding service to the DSIs, including Vanalco or Alcoa," had been made. Berwager *et al*., WP-02-E-BPA-38, at 7. Similarly, BPA witnesses clearly stated that the Compromise Approach was an agreement by BPA to propose and support an initial rate proposal but remained subject to change in the rate case. Berwager *et al.*, WP-02-E-BPA-38, at 8. In a sworn declaration filed in Federal court, BPA Administrator Judith Johansen refuted Alcoa's and Vanalco's allegations that she predecided the outcome of the rate case. Speer *et al*., WP-02-E-AL/VN/EG-02, at 2.

<u>Evaluation of Positions</u>

Given that the arguments by Alcoa and Vanalco that BPA violated section 7(i) are substantially the same as their arguments that BPA infringed on their constitutional rights, BPA incorporates by reference into this section its responses to Alcoa's and Vanalco's constitutional arguments, set forth above.

In addition, from BPA's perspective, the fact that the "Compromising DSIs" elected not to challenge the Compromise Approach is irrelevant to whether the record is "full and complete." Each party to the rate proceeding is free to make its own decisions regarding which issues to challenge. Each of the DSIs, including Alcoa and Vanalco, had the choice to accept or reject the Compromise Approach proposal. By accepting the Compromise Approach, the "Compromising DSIs" made a decision at the outset of the proceeding that they had more to gain by agreeing with the Compromise Approach proposal than by arguing various DSI service alternatives in the rate case. The record reflects the fact that the majority of DSIs found the Compromise Approach proposal acceptable, and that Alcoa and Vanalco did not.

Alcoa's and Vanalco's argument that BPA pre-judged the outcome of the rate case is equally misguided. The Compromise Approach was part of BPA's initial proposal for purposes of the rate case, and was treated the same as any other aspect of BPA's initial proposal. BPA did not predecide the outcome of this issue, or any other issue in this proceeding. As noted in BPA's rebuttal testimony:

> The Compromise Approach is an agreement by BPA to propose and support an Initial Proposal consistent with the Compromise Approach, but the proposal is subject to change in the rate case. BPA often fashions both the outlines and the details of rate case proposals with its customers prior to the commencement of a rate case, for example, through its rate case workshops. This is not unusual and in fact is appropriate. BPA tries to formulate rate proposals that it believes will be largely acceptable to its customers, and such proposals can only be formulated through negotiation and compromise with its various classes of customers.

Berwager *et al*., WP-02-E-BPA-38, at 8.

In lawsuits filed by Alcoa and Vanalco in Federal court, Alcoa and Vanalco argued, as they do here, that BPA predecided the outcome of the rate proceeding. *See Alcoa, Inc. et al. v. Bonneville Power Administration*, Nos. 99-71188 & 99-71189 (dismissed February 9, 2000). In response, BPA produced a sworn Declaration of Judith Johansen, BPA Administrator. In her sworn Declaration, Administrator Johansen states:

> I have made no final decisions regarding the rate for power to be sold to Bonneville's direct service industrial customers, including Alcoa or Vanalco, or the amount of power that would be allocated to Bonneville's direct service industrial customers, including Alcoa or Vanalco. Similarly, I have made no final decisions that result in Alcoa or Vanalco paying a higher rate for power, or receiving a smaller allocation of power, than the direct service industrial customers that signed the document referred to as the "Compromise Approach."

See Speer, *et al*., WP-02-E-AL/VN/EG-02, at 2.

BPA believes this sworn declaration squarely refutes Alcoa's and Vanalco's allegations that BPA prejudged the outcome of the rate case.

Decision

BPA did not violate the integrity of section 7(i) of the Northwest Power Act or predecide the outcome of any aspect of the rate proceeding.

15.5.3 Obligation To Serve

Issue

Whether BPA has a statutory obligation to serve DSI load after September 30, 2001.

Parties' Positions

Alcoa and Vanalco argue that BPA has a continuing obligation to serve the DSIs after the 1981 contracts, or their successors, expire on September 30, 2001, pursuant to the Pacific Northwest Consumer Power Preference Act of 1964, 16 U.S.C. §837-837(h) (Preference Act); the Northwest Power Act, 16 U.S.C. §839-839(h); and the Bonneville Project Act, 16 U.S.C. §832-832(m). Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 80-89. They argue that even if BPA has no statutory obligation to sell power to the DSIs, this does not mean that BPA, as an agency of the government, has the unfettered discretion to use any procedure it chooses to decide how or whether to allocate power to the DSIs. *Id*. at 80. They state that neither Alcoa nor Vanalco believed that their contribution "to pay for BPA's system from 1939 forward" would be disregarded, or that contrary to BPA statutes they would be denied the opportunity to share in the benefit of low-cost power provided by that system. *Id*. at 83.

Alcoa and Vanalco argue that the legislative history of the Regional Preference Act leaves "no doubt" that BPA must supply power to the DSIs before it may sell power out-of-region, and that "protecting the DSIs" was a primary purpose of the Regional Preference Act. *Id*. at 84-85. They conclude that the Regional Preference Act requires that before BPA offers to sell any power outside the Northwest it must offer such power to the DSIs at cost-based rates, and that BPA's intent to sell 1,164 aMW of power to out-of-region loads over the five-year rate period violates the Regional Preference Act because the "full requirements" of the DSIs will not be met first. *Id*. at 86, 88. Alcoa and Vanalco argue that BPA's authority to acquire resources under section 6(b) of the Northwest Power Act, 16 U.S.C. §839d(b)(1), *et seq*., taken together with the legislative history of that Act, indicating a "national interest" in continuing sales to the DSIs engaged in the smelting of nickel and aluminum, show that BPA "has no discretion to disobey Congress and stop selling power to the DSIs." *Id*. at 89.

In their brief on exceptions, Alcoa and Vanalco appear to have copied the arguments largely verbatim from their initial brief, Alcoa/Vanalco Ex. Brief, WP-02-AL/VN-01, at 63-73; but also state that BPA appears to be arguing in the Draft ROD that their regional preference rights are limited to competing with out-of-region purchasers to buy power under the prevailing surplus power rate schedule. *Id*. at 71.

SUB argues that BPA should make a final determination regarding its statutory obligation to serve DSI load after September 30, 2001, because such sales impact the rates of other customers either directly or indirectly. SUB Ex. Brief, WP-02-R-SP-01, at 3.

BPA's Position

For the rate period FY 2002-2006, BPA has proposed to serve up to approximately one-half of existing DSI plant load, or roughly 75 percent of current DSI load placed on BPA under the IP-96 power rate. Berwager *et al*., WP-02-E-BPA-09, at 6. This proposal contemplates some amount of service under section 5(d)(1)(A) of the Northwest Power Act, 16 U.S.C. §839c(d)(1)(A)), to every DSI customer, including Alcoa and Vanalco. Therefore, the question whether BPA is obligated to continue directly serving DSI load after September 30, 2001, is not specifically at issue in this rate case. Nevertheless, a number of parties, including BPA, have stated in testimony or briefs that BPA does not have a statutory obligation to continue to directly serve DSI loads after expiration of the initial 1981 (or their successor 1996) power sales contracts when those contracts expire September 30, 2001. *See, e.g.*, Berwager *et al*., BPA-02-E-BPA-38, at 5, 12 (section 5(d) obligation); PPC Brief, WP-02-B-PP-01, at 51; Cross *et al*., WP-02-E-WA-01, at 7; SUB Brief, WP-02-B-SP-01, at 4; MAC Brief, WP-02-B-MA-01, at 8.

Also, the issue is relevant in the context of BPA's proposal for service to Alcoa and Vanalco, specifically the amount of power allocated to those companies and the price at which BPA is proposing to sell that power. BPA's proposals with respect to those two issues are supported, in part, by the discretionary as opposed to mandatory nature of BPA's proposal to serve Alcoa and Vanalco. Therefore, BPA will state its position on the points raised by Alcoa and Vanalco on this issue, and evaluate the merits of the arguments presented by Alcoa and Vanalco, but a final decision on this issue in this rate case is neither necessary nor appropriate. It is not necessary since, as noted, BPA's proposal contemplates service for at least some portion of load for every DSI customer. It is not appropriate since other customers, including the other DSIs, have not briefed this question. In any case, Vanalco, on March 15, 2000, filed a petition with the Ninth Circuit Court of Appeals seeking review of BPA's refusal to sell Vanalco surplus firm power at the IP-96 rate, which Vanalco believes BPA must do under the Northwest Power Act and Regional Preference Act. Another DSI, Kaiser Aluminum and Chemical Corporation, filed a similar petition on April 4, 2000. Therefore, at least some of the issues raised here by Alcoa and Vanalco have already been set before the Ninth Circuit.

In addition, when Alcoa and Vanalco assert that BPA has an obligation to serve the DSIs, we assume they mean an obligation to directly serve DSI load under a power sales contract by and between BPA and the DSI, as opposed to some obligation to serve DSI load indirectly through sales to BPA's public utility customers, which raises separate and distinct issues that will not be addressed here.

With respect to the Northwest Power Act, it seems clear from both the plain language of that statute, and those pieces of legislative history from the Northwest Power Act that address this issue directly, that BPA has the authority, but not the obligation, to offer any DSI a follow-on contract under section 5(d)(1)(A) following the expiration of the initial section 5(d)(1)(B) contracts (initial contracts). Likewise, BPA does not agree with Alcoa and Vanalco that the Regional Preference Act of 1964 provides an independent source of an obligation by BPA to serve the full requirements of the DSIs at cost-based rates before making any out-of-region sales.

<u>Evaluation of Positions</u>

The argument by Alcoa and Vanalco that the Regional Preference Act and its legislative history "require BPA to serve the DSIs" at cost-based rates is incorrect. Alcoa and Vanalco appear to argue two points here: (1) that BPA has an obligation to meet the "full requirements" of Alcoa and Vanalco before making sales of power to any out-of-region customer; and (2) that the sale of such power to Alcoa and Vanalco must be at a "cost-based rate." Alcoa and Vanalco argue that "protecting the DSIs was a primary purpose of the Regional Preference Act." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 85. The excerpts of legislative history cited by Alcoa and Vanalco do indicate Congress was concerned that the proposed new transmission intertie between the PNW and PSW not be used in a way that would be detrimental to "the electroprocess industries" and the jobs that industry sustained. *Id*. However, Alcoa and Vanalco stray from both the Regional Preference Act and any cited legislative history when they conclude that the Regional Preference Act requires BPA to meet the "full requirements" of any DSI "at cost-based rates" before selling any Federal power outside the PNW.

Section 1(c) of the Regional Preference Act defines "surplus energy" as

> . . . electric energy generated at Federal hydroelectric plants in the PNW which would otherwise be wasted because of the lack of a market therefor in the PNW at any established rate.

16 U.S.C. §837(c).

Section 9(c) of the Northwest Power Act reiterated that sales of surplus power outside the region were subject to the notice and recall provisions of the Regional Preference Act, but also clarified the definition of surplus energy to mean:

> . . . electric energy for which there is no market in the PNW at any rate established for the disposition of such energy . . .

16 U.S.C. §839f(c).

The language in section 9(c) made it clear that the phrase “any established rate” used in section 1(c) of the Regional Preference Act meant more precisely “any rate established for the disposition of such energy.” Section 5(f) of the Northwest Power Act authorizes the Administrator to market power that is surplus to her obligations to serve PNW customers under sections 5(b) (public customers), 5(c) (IOU), and section 5(d) (DSI customers). The rates for the “disposition of such energy” are established pursuant to section 7(f) of the Northwest Power Act. 16 U.S.C. §839e(f). Currently, the Firm Power Products and Services (FPS-96) rate schedule is the applicable schedule for such sales. In general, firm surplus power sales under FPS-96 are priced at negotiated rates that, while in the aggregate are projected to recover BPA’s costs, on a case-by-case basis are priced based on market conditions. *See* 1996 ROD, WP-96-A-02, at 60-65. This, then, is the “rate established for the disposition of such energy.” Alcoa and Vanalco argue the Regional Preference Act requires BPA to sell firm surplus power to them at some unspecified cost-based rate. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 85-86. To the extent that this is a reference to the Industrial Firm Power rate established pursuant to section 7(c)(2) of the Northwest Power Act, or to some rate other than the rate or rates established under section 7(f), BPA disagrees. The established rate for the firm surplus energy specified in sections 1(c) of the Regional Preference Act and section 9(c) of the Northwest Power Act would be any rate negotiated by BPA and the customer for the sale under the FPS-96 rate schedule.

Next, BPA does not agree with Alcoa and Vanalco that BPA, in fact, has an obligation at all times under the Regional Preference Act to meet their “full requirements” before making sales of power outside the region. BPA agrees that so long as Alcoa and Vanalco maintain a power sales contract with BPA, they remain a “PNW customer” of BPA. The Regional Preference Act specifies that the full requirements for electric energy of “any PNW customer” will take priority over sales outside the region. Absent a contract, Alcoa and Vanalco are not “customers” of BPA. “PNW customer” is defined at section 1(f) of the Regional Preference Act to include “any purchaser from the United States for direct consumption in the PNW.” 16 U.S.C. §837(f). At the time the Regional Preference Act was enacted, this would have included any industrial entity in the region, and contemplated the direct sale of Federal power by BPA to such entities. However, this broad definition was necessarily delimited by section 5(d)(2) of the Northwest Power Act, enacted on December 5, 1980, which prohibits the Administrator from selling power directly to new DSI customers. 16 U.S.C. §839c(d)(2). Therefore, the class of direct service industrial customers was limited to those industrial customers that had a contract for the purchase of power from BPA on December 5, 1980. *See* 16 U.S.C. §839c(d)(4)(A), (B). Arguably, Alcoa and Vanalco would lose this status, and their status as a “PNW customer” under the Regional Preference Act, if the Administrator elected not to offer them new contracts.

In addition, as noted above, section 5(f) of the Northwest Power Act authorizes the Administrator to:

> . . . sell, or otherwise dispose of, electric power, including power acquired pursuant to this and other Acts, that is surplus to [her] obligations incurred pursuant to subsections (b), (c), and (d) of this section in accordance with this and other Acts applicable to the Administrator . . .

16 U.S.C. §839c(f).

Subsection (d) referred to in this passage is the provision authorizing sales by BPA to the DSIs. If there is no obligation to offer Alcoa and Vanalco a new power sales contract under section 5(d), then the Administrator has met her "obligations incurred pursuant to subsections (b), (c), and (d)" and Alcoa and Vanalco have no right to have their "full requirements" met before BPA may make sales outside the PNW. This is where the Regional Preference Act and the Northwest Power Act intersect: if there is no obligation to offer Alcoa and Vanalco a follow-on section 5(d) contract, then any power remaining after the Administrator has met her obligations under sections 5(b) and 5(c) is surplus, irrespective of the load status of Alcoa and Vanalco. Alcoa and Vanalco state in their brief on exceptions that BPA appeared to argue in the Draft ROD that their regional preference rights are to compete with out-of-region purchasers to buy power under the prevailing surplus power rate schedule. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 71. This is not correct. So long as Alcoa and Vanalco maintain their status as a "Pacific Northwest customer" under the Regional Preference Act, they will have preference to surplus power over out-of-region customers. However, as explained above, this power would be available under the prevailing surplus power rate schedule, not the Industrial Firm Power rate schedule. But even if Alcoa and Vanalco maintain their "customer" status under the Regional Preference Act, BPA disagrees that it is obligated to meet their "full requirements" before it may make any out-of-region sales, if by "full requirements" they mean their total plant load. If Alcoa and Vanalco do have new section 5(d) contracts, their regional preference rights are delimited by the total load amount served under that contract.

Turning to the Northwest Power Act, Alcoa and Vanalco argue that BPA is obligated to offer a new power sales contract to the DSIs because section 6(b) of the Northwest Power Act "created authority for BPA to augment the [Federal Base System] by purchasing power to enable sales to the DSIs." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 89. They argue that this is made more clear by excerpts from the legislative history of that Act indicating that continued sales of power by BPA to the DSI smelters was in the national interest. *Id*. They dismiss as ambiguous the oft-cited passage from the legislative history of the Northwest Power Act that "subsequent contracts for these DSIs are authorized but not mandated," but contend that this ambiguity is clarified in favor of an interpretation that Congress intended to mandate BPA service to the DSIs after September 30, 2001, by giving BPA its power purchasing authority, and by referring to continued service to the DSIs as in the "national interest."

The statement from the House Report addressing the issue of follow-on contracts reads in full:

> Section 5(d) authorizes the Administrator to sell power to existing direct service industrial customers that have a BPA contract at the date this bill is enacted. Initial long-term 20-year contracts are to be offered by BPA to these customers in accordance with section 5(g). In return for these new contracts, the DSIs would have to agree to terminate their current contracts. Subsequent contracts for these DSI's [sic] are authorized but not mandated."

H.R. Rep. No. 96-976, 96th Cong., 2d Sess., Pt. I at 61 (May 15, 1980).

While BPA considers this a dispositive statement of Congressional intent that follow-on DSI contracts are discretionary, it is not necessary to resort to this piece of legislative history to arrive at that conclusion. Section 5(d)(1)(A) states that "the Administrator is authorized" to sell power to the DSIs. Section 5(d)(1)(B) states that "the Administrator shall" offer the DSIs an initial long-term contract for an amount of power equivalent to that which the DSI was entitled to under its 1975 contract with BPA. The contrast is clear: one provision is mandatory, the other discretionary. If Congress had intended that follow-on contracts under section 5(d)(1)(A) be mandatory as well, it would have so stated.

In addition, there is nothing in section 6 of the Northwest Power Act (16 U.S.C. §839d(a)(1)) indicating that Congress intended that BPA must use its resource acquisition authority under that section to serve DSI load. In particular, section 6(a)(2)(A) only directs the Administrator to acquire sufficient resources to meet her contractual obligations. Alcoa and Vanalco have gotten ahead of themselves: absent a contract, the Administrator has no obligation to acquire resources to serve them. Furthermore, the conclusion that section 6 obligates the Administrator to make purchases to serve Alcoa and Vanalco is not consistent with section 5(b)(1) of the Northwest Power Act (16 U.S.C. §839c(b)(1)) which requires BPA to meet, when requested, the net firm power requirements of BPA's Northwest public body, cooperative, and IOU customers. If Congress had intended to mandate service by BPA to the DSIs after the termination of the initial long-term contract on September 30, 2001, it could have included the DSIs as a net-requirements customer under section 5(a)(1). Absent the status of a net-requirements customer, and the concomitant right to a net-requirements contract, the Administrator has no obligation to use her section 6 purchasing authority to serve Alcoa or Vanalco.

SUB argues that BPA should make a final determination regarding its statutory obligation to serve DSI load after September 30, 2001, because such sales impact the rates of other customers either directly or indirectly, and as such the issue has a direct bearing in this case.
SUB Ex. Brief, WP-02-R-SP-01, at 3. SUB urges BPA to find it has no such obligation, particularly in the case where there is a request for service from a preference customer. *Id*. However, the direct or indirect impact on other customers occurs whether DSI sales are mandatory or discretionary, and since it is BPA's proposal to establish rates to make power available to serve some portion of each DSI's load in the next rate period, a final decision on whether that proposal is required by statute is not required. Also, BPA continues to believe making a final determination in the ROD on this issue would be unfair to those parties that have not briefed this issue, perhaps partly or completely in reliance on BPA's position that it would not make a final decision.

Decision

Because BPA's proposal contemplates service to meet some portion of each DSI customer's load, it is not necessary for BPA to make a final decision whether it has the statutory obligation under the Northwest Power Act to offer the DSIs new power sales contracts after September 30, 2001. Additionally, the issue of whether BPA is obligated under the Regional Preference Act of 1964 to meet the full requirements of a DSI customer at cost-based rates before BPA may make any sales out-of-region is the subject of a petition currently pending before the Ninth Circuit Court of Appeals.

15.5.4 Rate Directives

Issue 1

Whether BPA may charge Alcoa and Vanalco a slightly higher rate than the rate BPA is proposing to charge the DSIs that signed the Compromise Approach agreement.

Parties' Positions

Alcoa and Vanalco argue that BPA has provided no legitimate basis for discriminating between the proposed rate for the DSIs that signed the Compromise Approach agreement and the proposed rate for Alcoa and Vanalco. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 12. They argue that BPA cannot link the difference in the proposed rates to a corresponding differential in cost of service, and that this failure is in itself fatal to BPA's proposal. *Id*. Alcoa and Vanalco assert that the sole reason BPA is proposing a higher rate for them is that BPA wanted to "silence potentially vocal adversaries in both the rate case and the broader political arena" and that such silence could not be obtained unless there was a penalty for speaking. *Id*. at 13-14. They argue that section 7(g) of the Northwest Power Act (16 U.S.C. §839e(g)) obligates BPA to equitably allocate to power rates in accordance with generally accepted ratemaking principles all costs and benefits which are not otherwise allocated by the rate directives. *Id*. Alcoa and Vanalco reason that because the proposed IPTAC rates are not made pursuant to the specific rate directive applicable to DSI rates, that this allocation must conform to the requirements of section 7(g). *Id*. at 14.

Alcoa and Vanalco argue that regulated utilities generally may not unduly discriminate among similarly situated customers, citing section 205(b) of the Federal Power Act (16 U.S.C. §824d(b)). *Id*. They note that in addition to cost-of-service distinctions, the courts have also recognized other factual differences that will justify disparate rates for otherwise similarly situated customers, including the existence of fixed rate contracts and certain rate settlements, but that BPA's proposal met none of these tests. *Id*. at 14-16.

In their brief on exceptions Alcoa and Vanalco appear to repeat largely verbatim the arguments made in their initial brief. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, 73-80. However, Alcoa and Vanalco state that BPA has not explained why the costs associated with the 450 aMW of purchases to be made to serve DSI load are not being equitably allocated to all DSIs under section 7(g) of the Northwest Power Act. *Id*. at 76.

BPA's Position

BPA's proposal to charge Alcoa and Vanalco a slightly higher rate (25 mills/kWh) than the rate proposed for the DSIs that signed the Compromise Approach Agreement (23.5 mills/kWh) is fully justified under the factual circumstances and business framework in which the proposal was made and, in any case, there is no anti-discrimination standard applicable to this discretionary sale of power by the Administrator to the DSIs.

BPA's DSI service proposal evolved through negotiations with the DSIs that occurred after publication of the Subscription Strategy in December 1998. Berwager *et al.*, WP-02-E-BPA-09, at 15. BPA's initial position in these negotiations was that it could propose in the rate case to offer the DSIs approximately 1,200 aMW of service at a rate of 25 mills/kWh. *Id*. This proposal was referred to as the Targeted Augmentation Approach, because BPA would use $25 million to augment its system and combine 500 aMW of power at approximately 21 mills/kWh with 700 aMW of market-priced power in order to provide the DSIs 1,200 aMW at a melded rate of 25 mills/kWh. *Id*. The DSIs indicated, however, that the Targeted Augmentation Approach proposal was inadequate to address the threat to continued smelter operations posed by low aluminum prices and rising market power prices. Tr. 272; Berwager *et al*., WP-02-E-BPA-09, at 6. BPA subsequently enhanced the offer it would be willing to propose in the rate case to include 1,500 aMW of power at a rate of 23.5 mills/kWh, and this offer came to be known as the Compromise Approach. *Id*. at 15. However, BPA explained to the DSIs that it was unwilling to ask other customers to bear additional costs to provide this enhanced level of service unless the DSIs would commit to supporting the Compromise Approach, and informed them that failure to do so would result in BPA going forward with the Targeted Augmentation Approach. *Id*. at 14-15. Offering service at the slightly higher Targeted Augmentation Approach rate to Alcoa and Vanalco appropriately reflects the loss of value that BPA had hoped to receive from their support--and which it did receive from the other DSIs--and is consistent with the signals BPA sent during the negotiations. *Id*. at 17.

In any case, there is no antidiscrimination standard that applies to the rates proposed by the Administrator for these discretionary sales to the DSIs. As explained in the preceding issue, BPA believes it has no statutory obligation to offer Alcoa or Vanalco a new power sales contract under section 5(d) of the Northwest Power Act after September 30, 2001. Both the Targeted Augmentation Approach proposal and the Compromise Approach agreement proposal are negotiated, discretionary offers of power by the Administrator. As such, the Administrator is not obligated to offer, following such negotiations, the same terms and conditions, including the same rates, to every member of a class of customer to whom the Administrator has no obligation to serve in the first instance.

In addition, BPA does not agree that section 7(g) of the Northwest Power Act requires a different result, or that the anti-discrimination standards under the FPA, or the cases applying those standards, have any application to this proposal.

Evaluation of Positions

Alcoa and Vanalco are wrong to conclude there is no legitimate basis for the Administrator's proposal to offer them power at a higher rate than that offered to the DSIs that signed the Compromise Approach.

Alcoa and Vanalco first argue that absent a cost-of-service basis for the difference between the rates, that BPA must offer Alcoa and Vanalco the same rate offered to the other DSIs. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 12. Given the uncertainty about whether Alcoa and Vanalco would purchase from BPA even at 23.5 mills/kWh, there certainly is some part of the 1.5 mills/kWh difference between the two proposed rates that could be attributed to the cost and risk associated with planning to serve that load. Berwager *et al*., WP-02-E-BPA-38, at 5-6. It is difficult to see how the letter from Alcoa to BPA regarding the Compromise Approach cited by Alcoa and Vanalco can be read to indicate that Alcoa would purchase any power from BPA at 23.5 mills/kWh, Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, Attachment 2; so it seems reasonable to conclude that making augmenting purchases on behalf of these companies carries more risk than purchases made on behalf of companies supporting the proposal. However, whether BPA correctly interpreted these companies' purchase intentions is ultimately not important, because any cost risk associated with that uncertainty is not the primary reason there is a 1.5 mill/kWh difference between the proposed rates. In fact, the 1.5 mill/kWh difference between the rates is reflective of the difference between the Targeted Augmentation Approach and the Compromise Approach.

The Administrator was willing to make a proposal for service to the DSIs of 1,200 aMW at an average rate of 25 mills/kWh without any corresponding return of consideration from the DSIs. Berwager *et al*., WP-02-E-BPA-09, at 16. This was the Targeted Augmentation Approach proposal. Further negotiations ensued after the DSIs indicated this proposal was inadequate to address the threat to continued smelter operations posed by low aluminum prices and rising market power prices. Tr. 272; Berwager *et al*., WP-02-E-BPA-09, at 6. At that point, and in the context of a business negotiation, the Administrator determined that it was necessary to secure some level of consideration from the DSIs in return for an enhanced proposal. All the DSIs, except Alcoa and Vanalco, agreed to support the Compromise Approach agreement pursuant to the terms contained in a June 18, 1999, letter from BPA to each DSI customer. *See* Berwager *et al*., WP-02-E-BPA-09, at Attachment 1.

In general, in exchange for the enhanced level of service offered in the Compromise Approach, the signing DSIs agreed: (1) to support the Compromise Approach in the rate case and in other venues; (2) not to legally challenge the Compromise Approach if it was substantially sustained in the rate case Final ROD, (3) not to challenge in the rate case BPA's proposal for the sale of power under the Subscription Strategy to the investor-owned utilities, or to file litigation challenging that proposal if the Compromise Approach was substantially sustained in the Final ROD (unless the Subscription Strategy proposal for service to the DSIs was challenged by certain parties); and 4) to argue to hold in abeyance pending litigation challenging the Subscription Strategy so long as BPA was supporting the Compromise Approach, and if the Compromise Approach was substantially sustained in the Final ROD, to withdraw that litigation (unless the Subscription Strategy proposal for service to the DSIs was challenged by certain parties). *Id*.

In the framework of this arms-length negotiation, BPA determined it could not justify offering Alcoa and Vanalco the same terms of service offered to DSIs giving BPA this substantial consideration in exchange for the enhanced service proposal in the Compromise Approach agreement. Berwager *et al*., WP-02-E-BPA-09, at 16. A commitment to support the Compromise Approach agreement would have little meaning or value to BPA, the DSIs that supported the proposal, or to other customers if the rate under the Compromise Approach was made available regardless of whether a DSI committed to supporting the proposal or agreed to the other consideration reflected in that agreement. *Id*. Service to Alcoa and Vanalco at a rate 1.5 mills/kWh higher than the rate offered to the other DSIs equals the difference between the penultimate offer embodied in the Targeted Augmentation Approach and the enhanced proposal in the Compromise Approach, reflects the loss of value that BPA had hoped to receive from their support, and is consistent with the signals that BPA sent during the negotiations. *Id*. at 17. When Alcoa and Vanalco declined to join the other DSIs in signing the Compromise Approach, BPA could have opted to offer these two companies nothing. In an attempt to demonstrate that there was no intent to unduly disadvantage Alcoa and Vanalco for their decision, BPA instead decided to carry into the rate case for them the original, and below-market, Targeted Augmentation Approach proposal. Berwager *et al*., WP-02-E-BPA-38, at 3-4.

The Compromise Approach proposal represents a discretionary allocation of power by the Administrator to the DSIs under section 5(d) of the Northwest Power Act. 16 U.S.C. §5(d)(1)(A). Simply stated, the Administrator, exercising her ability to make discretionary sales to the DSIs, was giving value and expected, as a business proposition, to receive some value in return. Neither Alcoa nor Vanalco have a statutory right to a follow-on power sales contract under section 5(d)--at any rate. It is unreasonable for Alcoa and Vanalco to argue that the Administrator must propose to offer them the same allocation and rate enhancements proposed for the DSIs that signed the Compromise Approach agreement. The consequence of adopting this argument would be to greatly undermine, if not render completely impotent, the Administrator's bargaining power in cases such as this. Such a result is neither reasonable from a business perspective, nor required by the statutory provisions or ratemaking principles cited by Alcoa and Vanalco.

Alcoa and Vanalco next argue that section 7(g) of the Northwest Power Act (16 U.S.C. §839e(g)) obligates BPA to equitably allocate to power rates in accordance with generally accepted ratemaking principles all costs and benefits which are not otherwise allocated by the rate directives. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 13-14. Alcoa and Vanalco reason that because the proposed IPTAC rates are comprised of a combination of power priced under section 7(c)(2) of the Northwest Power Act and power priced at market rates, the allocation of these costs (market purchases) and benefits (power available at the section 7(c)(2) rate) is not made pursuant to the specific rate directive applicable to the DSIs, and therefore must conform to the requirements of section 7(g). *Id*. at 14. In the context of their assertion that the rate provisions do not contemplate different rates for similarly situated customers, Alcoa and Vanalco appear to argue that because only part of the power proposed to be allocated to the DSIs

(990 aMW of 1,440 aMW) is priced at the section 7(c)(2) rate, the costs of the entire amount must be allocated uniformly to the DSIs at a single rate pursuant to section 7(g).

In fact, the rates applicable to each component of the proposal--990 aMW at the 7(c)(2) rate of 20.98 mills/kWh and 450 aMW at the projected market rate of 28.1 mills/kWh--is the same for all DSIs, including Alcoa and Vanalco. However, the DSIs supporting the Compromise Approach have a higher percentage of their allocation (870 aMW or 72 percent) coming from this cost-based section 7(c)(2) portion than do Alcoa and Vanalco (120 aMW or 52 percent). Berwager *et al*., WP-02-E-BPA-09, at 17. However, that fact has nothing to do with how the costs of the 990 aMW or the 450 aMW are allocated, but rather reflects the smaller allocation and slightly higher rate under the Targeted Augmentation Approach being made available to Alcoa and Vanalco. Conversely, Alcoa and Vanalco are also paying the same rate for their share of the 450 aMW as the other DSIs, but their allocation simply consists of a larger portion of this higher cost power. The issue is not so much how costs have been allocated under the rate directives, but rather how the Administrator has exercised her discretion in allocating benefits to the companies.

Notwithstanding this fact, section 7(g) does not require the result advocated by Alcoa and Vanalco. Section 7(g) states in pertinent part:

> [T]he Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this chapter, all costs and benefits not otherwise allocated under this section, including, but not limited to, conservation, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under section 839d of this title, the cost of credits granted pursuant to section 839d of this title, operating services, and the sale of or inability to sell excess electric power.

16 U.S.C. §839e(g).

Section 7(g) addresses the allocation of costs not otherwise allocated by the rate directives "to power rates." In other words, section 7(g) costs are allocated across all power rates, including non-DSI power rates. Section 7(g) does not address the allocation, equitable or otherwise, of rates within a customer class. Therefore, Alcoa and Vanalco's suggestion that section 7(g) requires that the "costs and benefits" of the 1,440 aMW must be equitably or uniformly allocated between the DSIs is misplaced. Alcoa and Vanalco state in their brief on exceptions that this analysis is insufficient. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 76. However, because section 7(g) does not address intra-class allocations of power costs not otherwise allocated under the rate directives, it simply has no application to the issue. That fact alone would appear to provide a sufficient explanation. The consequence of adopting the proposal of Alcoa and Vanalco and allocating the costs of the 450 aMW market purchase equally between the DSIs would be to confer on Alcoa and Vanalco the benefits of the Compromise Approach agreement without those companies being required to meet the obligations under that agreement.

If Alcoa and Vanalco are arguing that section 7(g) requires that the entire 1,440 aMW be allocated across all power rates because the IPTAC rates are not being priced in total under section 7(c)(2), this is also incorrect. BPA acknowledges that the direct assignment of purchase power costs to a particular customer class is unique. Berwager *et al*., WP-02-E-BPA-38, at 12. However, the direct assignment to the DSIs of the costs associated with the purchase of the additional 450 aMW is justified in light of the novel facts and circumstances under which BPA's DSI service proposal is being made. *Id*.

One novel fact, as noted, is that the Administrator is not obligated to make any section 5(d) sales to the DSIs after September 30, 2001. Likewise, the decision to purchase 450 aMW to serve DSI load is also a discretionary. BPA's objective in making these sales is to enhance DSI smelter survivability, but without raising other customers' rates; the extent of BPA's ability to roll into all customers' rates the cost of augmenting purchases to meet DSI load and still satisfy these competing principles is 990 aMW. *Id*. However, BPA's goal of enhancing the prospects of DSI survivability is best achieved through a proposal that offers more power than would be available at the cost-based rate (990 aMW) by making this additional market based purchase of 450 aMW. *Id*. at 11-12. The best way to reconcile the competing goals of enhancing survivability with no additional cost to other customers is to allocate the full cost of the 450 aMW to the DSIs, which every DSI other than Alcoa and Vanalco agreed to as part of the Compromise Approach agreement. Simply put, if BPA were compelled by section 7(g) to allocate the costs to all power rates of these discretionary purchases made in support of a discretionary sale--which it is not--it would likely not make any service proposal for the DSIs. As explained elsewhere, to do so would frustrate BPA's policy goal of enhanced smelter survivability without rate increases to other customers. Section 7(g) contemplates the equitable allocation of costs not otherwise allocated by the rate directives to the power rates of *all* customer classes, but the costs of this power are not properly allocable to other customers in the context of this proposal.

Finally, Alcoa and Vanalco argue that BPA's proposal to charge them a higher rate than other DSIs violates section 205(b) of the Federal Power Act (FPA), 16 U.S.C. §824d(b), and some cases interpreting that provision. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 14-16. Of course, section 205(b) of the FPA, which prohibits undue preference or advantage or undue prejudice or disadvantage in rates, applies only to "public utilities," and so is not applicable to BPA. Likewise, the cases cited by Alcoa and Vanalco establishing criteria for when different rates applicable to otherwise similarly situated customers are justified are not applicable to BPA ratemaking.

Some provisions in BPA's organic statutes do expressly forbid discrimination by the Administrator. For example, section 6 of the Transmission System Act requires the Administrator to make transmission capacity in excess of BPA's requirements available to all utilities on a fair and nondiscriminatory basis. 16 U.S.C. §838d. No such provision exists with respect to the formulation of rates for discretionary sales of power by the Administrator to the DSIs, and the courts will not apply such a standard where Congress has not made one expressly applicable. In *Southern California Edison v. Jura*, 909 F.2d 339 (9th Cir. 1990), the court refused to apply a nondiscrimination standard to BPA's extraregional nonfirm energy rates where Congress did not expressly provide one for such rates, but had "expressly prohibited discrimination or 'undue' discrimination in other very similar administrative contexts," including section 205(b) of the Federal Power Act. *Id*. at 343. Similarly, in *Aluminum Co. of America v. Bonneville Power Admin.*, 903 F.2d 585 (9th Cir. 1989), in discussing the applicability of section 825s of the Flood Control Act to the establishment of extraregional nonfirm rates, the court held that "no 'fair and reasonable' standard is applicable to BPA ratemaking." *Id*. at 591.

Even if such a standard did apply in this case, BPA has articulated a strong factual rationale for the higher rate it proposed to charge Alcoa and Vanalco. Charging these two companies a slightly higher rate is consistent with the negotiated nature of these sales and the context of the Compromise Approach agreement. Requiring the Administrator to offer Alcoa and Vanalco the same rate paid by DSIs willing to offer the Administrator valuable consideration in return would seriously undermine the Administrator's ability to operate BPA in a business-like manner. Alcoa and Vanalco argue that the most important fact arguing against BPA's proposal is that BPA is not a private utility, but a government agency that is both the rate applicant and the decisionmaker. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 16. However, Congress endowed the Administrator "with broad-based powers to act in accordance with BPA's best business interests--powers not normally afforded government agencies." *Association of Public Agency Customers v. Bonneville Power Admin.*, 126 F.3d 1158, 1170 (9^{th} Cir. 1997).

Of course, any defect to the rates proposed for Alcoa or Vanalco may be cured by simply not offering a new power sales contract to these two companies. Although BPA's proposal for service to the DSIs contemplates service to both Alcoa and Vanalco, the actual decision whether to offer a power sales contract based on the service proposal ultimately adopted by the Administrator in the rate case is not itself a rate case issue.

Decision

The decision to charge Alcoa and Vanalco a slightly higher rate than the DSIs that signed the Compromise Approach is justified by strong business and policy considerations and is not otherwise prohibited by law.

Issue 2

Whether the method used to calculate the industrial IPTAC rates is inconsistent with section 7(c)(2) of the Northwest Power Act.

Parties' Positions

Alcoa and Vanalco argue that the Northwest Power Act mandates that firm power sales to the DSIs be at the IP-02 rate as calculated by section 7(c)(2) of the Northwest Power Act, and that the proposed IPTAC rates are inconsistent with that provision. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 72-75. They note that of the proposed DSI service amount of 1,440 aMW, 990 aMW will be priced using a cost-based approach consistent with the IP-PF relationship of section 7(c)(2), but that the remaining 450 aMW will be melded in at a price that reflects the market price. *Id*. at 72. They argue that this runs afoul of section 7(c)(2) because it uses the IP-02 rate established by that provision as only one element of the IPTAC rates. *Id*.

Alcoa and Vanalco cite section 5(e)(1) of the Northwest Power Act for the proposition that there are only four classes of regional customers for firm power, and BPA's proposal for two IPTAC rates effectively creates a fifth class, in violation of both section 5(e)(1) and section 7(c)(2). *Id*. at 72-73. They argue that the proposal to link the 450 aMW of market-priced power with the 990 aMW of section 7(c)(2) priced power imposes an "improper tying arrangement," and that tying the DSIs' ability to purchase the 990 aMW with an obligation to purchase the 450 aMW of market-priced power is not authorized anywhere in the Northwest Power Act and is not justified, since BPA has sufficient amounts of critical water power to serve all regional firm load. *Id*. at 74.

Alcoa and Vanalco state that section 7(c) defines the revenues to be collected from the DSIs, and such revenues are not based on the resources serving these loads but are based on the PF rate plus a margin. *Id*. at 75. They argue that the cost of the resources used to serve them must be allocated to the "section 7(b) rate pool" and then priced under section 7(c)(2). *Id*. Alcoa and Vanalco conclude that the proposed IPTAC rates fail this legal standard because, by directly assigning to the DSIs the purchase costs of the 450 aMW, the IPTAC rate overrecovers the revenues lawfully allowed by section 7(c)(2), and that the IPTAC rates unlawfully combine a section 7(c) sale and a section 7(f) sale. *Id*.

Alcoa and Vanalco repeat most of these arguments in their brief on exceptions. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 80-86.

BPA's Position

BPA's proposal is to offer the DSIs 1,440 aMW, but to price only 990 aMW (approximately 69 percent) of this amount at the cost-based section 7(c)(2) rate. The projected purchase power costs of the remaining 450 aMW would be allocated directly to the DSIs. BPA's proposal is to combine the two components (990 aMW priced at 20.98 mills/kWh and 450 aMW priced at 28.1 mills/kWh) to create the IPTAC rates (23.5 and 25 mills/kWh) applicable to the sale of the 1,440 aMW. Nothing in the Northwest Power Act prohibits the Administrator from allocating directly to the DSIs the purchase power costs made to support a discretionary sale to those customers. Because the proposed sale is discretionary, the Administrator may allocate as much or as little of the costs of that discretionary purchase and sale to the section "7(b) rate pool" as she determines is appropriate and consistent with BPA's other ratesetting goals. In this case, the Administrator proposed to allocate to that pool 990 aMW of the 1,440 aMW needed to support sales to the DSIs, because that is the amount that can be allocated to the rates paid, in part, by other customers without triggering a rate increase over current levels. This 990 aMW is then priced pursuant to section 7(c)(2) for sale to the DSIs.

However, the Administrator has elected to propose serving an additional 450 aMW (for a total of 1,440 aMW) of DSI load at below market rates in response to the concern that, absent the availability of a substantial amount of low-cost Federal power, a significant number of family-wage aluminum smelter jobs in the region will be at risk. Berwager *et al*., WP-02-E-BPA-09, at 6. BPA's proposal is to allocate the costs of this 450 aMW directly to the DSIs. *Id*. at 8-9. Nothing in the Northwest Power Act requires that the additional 450 aMW be allocated to the section 7(b) rate pool and priced under section 7(c)(2).

BPA's ability to achieve the goals of enhancing the prospects of DSI smelter survivability and associated jobs, while not simultaneously raising other customers' rates, is best achieved through the proposal to offer more power than would be available to the DSIs at the cost-based 7(c)(2) rate (990 aMW). Berwager *et al*., WP-02-E-BPA-38, at 9. This is accomplished by making additional market-based purchases (450 aMW), allocating the costs directly to the DSIs, and melding the costs of the two components together, creating the IPTAC rates. *Id*. at 10. Another benefit that BPA receives from blending the two amounts of power into a single amount offer is that the entire amount will be subject to the power CRAC, which provides BPA and its other customers a higher level of risk protection than would be the case if the amount was limited to 990 aMW. *Id*. at 12.

Evaluation of Positions

Alcoa and Vanalco argue that all firm power sales by BPA to the DSIs must be priced under section 7(c)(2) of the Northwest Power Act. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 75. Whether BPA is obligated to price all firm power sales to the DSIs under section 7(c)(2) must be examined in the context of three important circumstances surrounding BPA's DSI service and rate proposal: (1) the Administrator has no obligation to offer a new section 5(d) power sales contract to the DSIs for the period after September 30, 2001; (2) the Administrator is exercising her discretion to make such sales in order to enhance the prospects of DSI smelter survivability, and the jobs associated with those operations, through the next rate period; and (3) a limitation on the proposal was that it not require rate increases for BPA's other customers. The argument by Alcoa and Vanalco that BPA must price the entire 1,440 aMW amount at the section 7(c)(2) rate is neither required by the statutes nor consistent with the discretionary nature of the proposal or the goals that have shaped it.

Given the third element of the Administrator's proposal (no rate increases for other customers), if BPA were in fact required to include the costs of the 450 aMW of augmenting power purchases in the section 7(b) rate pool and price that power under section 7(c)(2), the Administrator simply would not exercise her discretion to make that power available in the first instance. However, given the second element of the proposal (enhancing smelter survivability), the total amount of service (1,440 aMW) is important. Allocating only 990 aMW to the DSIs would represent substantially less than half of each DSI's potential load in the region. Berwager *et al*., WP-02-E-BPA-09, at 9. This smaller amount might encourage the use of reduced production schedules to manage energy costs, and would be inconsistent with BPA's focus on helping to maintain as many DSI jobs in the region as possible consistent with BPA's other marketing and ratemaking goals. *Id*. Adding the 450 aMW and allocating the costs of the power directly to the DSIs, then melding those purchases with the 990 aMW priced under section 7(c)(2), materially aids smelter survivability by encouraging the broad use of these benefits over a larger DSI load than would be the case if the amount were only the cost-based portion. Berwager *et al*., WP-02-E-BPA-38, at 9.

Section 7(c)(2) has two principal requirements: (1) that rates for the DSIs be established at a level which the Administrator determines to be equitable in relation to the retail rates charged by public body and cooperative customers to their industrial customers in the region, 16 U.S.C. §839e(c)(1)(B); and (2) that such rates in no event be less than the rates in effect for the contract year ending June 30, 1985 (the floor rate), 16 U.S.C. §839e(c)(2). BPA is not taking the position that just because section 5(d) sales to the DSIs after September 30, 2001, are discretionary, that section 7(c)(2) is not applicable to such sales. In particular it is important that, on average measured across the rate period, the proposed DSI rate recover revenues that are equal to or greater than revenues under the section 7(c)(2) floor rate. This element of the test is clearly met in this case, because the proposed floor rate is 20.98 mills/kWh, lower than the proposed IPTAC rates. *See supra*, at 15.2.3. With respect to the equitable rate requirement, BPA proposed to allocate the maximum amount it can to the section 7(b) rate pool (990 aMW), and price such power at the "equitable" section 7(c)(2) rate, and still maintain its other ratemaking goals, primarily its goal to not increase the rates of its other customers. Berwager *et al*., WP-02-E-BPA-38, at 12. However, absent allocating another 450 aMW to the DSIs, BPA's survivability goals are frustrated, but allocating the costs of that power to the 7(b) rate pool is not possible without increasing other customers' rates. *Id*. The result is that if BPA were required to allocate the 450 aMW to the 7(b) pool and price that power under section 7(c)(2), the Administrator would effectively be placed in the position of making no proposal for serving DSI load. In the context of discretionary post-2001 sales, it is not reasonable to read section 7(c)(2) to require such a result.

Alcoa and Vanalco cite section 5(e)(1) (16 U.S.C. §839c(e)(1)) for the proposition that Congress contemplated only four rate classes, and that the proposal to have two IPTAC rates divides the DSI class into two distinct classes of customers, resulting in five rate classes, which is not authorized under section 7(c)(2) of the Northwest Power Act. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 72-73. However, section 5(e)(1) is not relevant to the question whether BPA may have different rates for members of the same class of customers, or whether the Northwest Power Act contemplates a single DSI rate calculated pursuant to section 7(c)(2). Section 5(e)(1) establishes certain parameters around the Administrator's right to restrict the contractual entitlement of customers to firm power. The provision creates the four categories of customers expressly and exclusively "[f]or purposes of this paragraph" implementing the restriction provisions, not for any ratemaking purpose. Alcoa and Vanalco argue that this logic is unresponsive to their argument. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 83. However, if the argument by these parties is that section 5(e)(1) creates exclusive and immutable rate classes for purposes of power ratemaking, then BPA's response that the provision has no application to ratemaking issues seems completely responsive. In any case, section 5(e)(1) addresses the contractual entitlement to firm power, which neither Alcoa or Vanalco will have after September 30, 2001, absent a new contract offer from the Administrator.

Alcoa and Vanalco argue that the proposal to link the 450 aMW of market-priced power with the 990 aMW of cost-based priced power constitutes an "improper tying arrangement" that is not authorized by the Northwest Power Act and is not necessary, because BPA has sufficient inventory to serve all regional firm load without such a proposal. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 73. First, BPA does not have sufficient inventory to serve Alcoa and Vanalco absent purchases to augment its inventory. Alcoa and Vanalco were able to argue there is sufficient inventory because they selectively exclude certain resources and load obligations in their determination that BPA has surplus energy. Rather than including all of BPA's loads and resources, Alcoa and Vanalco have hand picked certain loads and resources for inclusion and selectively ignored other loads and resources in the Loads and Resource Study. This manner of calculating the load/resource balance allows them to draw the conclusion that BPA has sufficient inventory. Had Alcoa and Vanalco included all of BPA's loads and resources, they would have found that on a fiscal year basis BPA is 38 MW deficit on a five-year average basis, and that on an operating year basis BPA is in load/resource balance. *See, generally,* Loads and Resources Study, WP-02-E-BPA-01; *see also,* Tr. 867-868.

Second, as explained above, the 450 aMW component of the Administrator's proposal, and its rate treatment, is critical to meeting the goal of enhanced survivability without rate increases. This is a discretionary allocation of power designed to meet these goals, and nothing in the Northwest Power Act prohibits the Administrator from exercising her discretion in the manner proposed. Nevertheless, BPA is taking on the risk that the expected costs of the 450 aMW will in fact be recovered. Berwager *et al*., WP-02-E-BPA-38, at 13. There is some risk that the cost of obtaining this power will be higher than forecast in the rate case, if BPA waits to purchase until the sales amount is known, or that the loads will not materialize once BPA has purchased the power, if it locks in the purchases before the sales amount is known. *Id*. Therefore, the implication that BPA is somehow financially benefiting from tying the market-based component to the cost-based component of the proposal is wrong. Alcoa and Vanalco also argue that the 450 aMW component of the proposed sale will be made more expensive for the DSIs because BPA's presence in the market will drive up prices. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 80-81. However, the rate for the 450 aMW market purchase component of this sale is being established at 28.1 mills/kWh, so BPA is taking the risk the price will be higher, not the DSIs.

Alcoa and Vanalco also argue that the proposed IPTAC rates unlawfully combine a section 7(c) and a section 7(f) sale. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 75. They cite excerpts from a past BPA ROD for the proposition that Congress did not intend BPA's DSI customers to pay for their direct service from BPA at a rate other than the section 7(c) rate. *Id*. However, the statements in the cited material were made in the context of mandatory direct sales to the DSIs under the mandatory section 5(d)(1)(B) initial long-term contracts. Again, the treatment of the 450 aMW is consistent with the discretionary nature of this proposal and is necessary to achieve the goals that underlie the proposal.

In the same context, Alcoa and Vanalco argue that the proposed IPTAC rates may not be justified simply as a matter of rate form allowed by section 7(e) of the Northwest Power Act (16 U.S.C. §839e(e)), because the proposal to assign to the DSIs the purchase cost of the 450 aMW means the IPTAC rates overrecover the revenues lawfully allowed by section 7(c)(2). Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 75. Section 7(e) provides that:

> Nothing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms.

16 U.S.C. §839e(e).

Section 7(f) provides that:

> Rates for all other firm power sold by the Administrator for use in the PNW shall be based upon the cost of the portions of Federal base system resources, purchases of power under section 839c(c) of this title and additional resources which, in the determination of the Administrator, are applicable to such sales.

16 U.S.C. §839e(f).

The IPTAC rates reflect BPA's proposal for a discretionary sale that provides the DSIs with a large quantity of below-market power, addressing the smelter survivability issue without raising other customers' rates. However, such a proposal, balancing these competing service and ratemaking goals, would not be possible if priced in total under section 7(c)(2), although the great majority of the power under this proposal (approximately 69 percent) is priced under section 7(c)(2). As already explained, the Administrator is not limited in this context to allocating to the 7(b) rate pool all the resources needed to serve the DSIs and pricing sales of those resources at the 7(c)(2) rate. In fact, she has elected to price 450 aMW of the proposed sale under section 7(f). So the argument of Alcoa and Vanalco that the IPTAC rates recover more than permissible under section 7(c)(2) is incorrect. The pool of resource costs appropriately allocated to the DSIs includes both the cost-based 990 aMW (section 7(c)(2) rate) and the market-priced 450 aMW (section 7(f) rate). Under this framework, section 7(e) provides an appropriate vehicle for the proposed IPTAC rates, which are designed to recover the costs of those resources.

Decision

In the context of this discretionary section 5(d) sale, the Administrator is not obligated to allocate all resources needed to support such sales to the section 7(b) rate pool and price such sales exclusively under section 7(c)(2). The IPTAC rates are not inconsistent with section 7(c)(2).

15.5.5 Allocation Methodology

Issue

Whether BPA should allocate power to the DSIs based on plant capacity.

Parties' Positions

Alcoa and Vanalco argue that BPA's proposal to allocate power to the DSIs based on the level of power purchases during the last 5-year period of the 20-year 1981 contract is a breach of that contract and a "1996 accord and satisfaction." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 76. They propose that the allocation be based on plant capacity. *Id*.

They argue that BPA "may not use its supposed exercise of discretion" in the selection of how to apportion the DSIs' power sales to punish Vanalco and Alcoa for exercising their rights under the 1981 contract. *Id*. at 78. They assert that BPA's proposal will force them to go to market for a substantial portion of their power needs, thereby substantially increasing the likelihood of Alcoa and/or Vanalco being forced to close smelters during the rate period, and that this is inconsistent with BPA's goal of offering a combination of power and rates to "ensure DSI survivability as a class." *Id*. at 79.

<u>BPA's Position</u>

BPA's proposal is to allocate available power to the DSIs according to the relative amounts of IP-96 power purchased by each DSI in the current rate period. Berwager *et al*., WP-02-E-BPA-09, at 7. DSIs that purchased larger amounts of IP-96 power from BPA during this period will be entitled to a larger proportional share of the available power than DSIs that placed less IP-96 load on BPA. *Id*.

The primary benefit BPA received from the DSIs that purchased under the IP-96 rate during the current rate period was a high degree of certainty that BPA would be able to cover its costs. Berwager *et al*., WP-02-E-BPA-38, at 11. Some purchased more than others, even though they could have obtained better prices in the short-term market, and the general consensus at the time was that BPA's proposed IP-96 rate would be above market through the rate period, and this created a benefit for BPA. *Id*.; Berwager *et al*., WP-02-E-BPA-09, at 8. It is entirely appropriate to reflect this benefit in how BPA will allocate available power when it enters into discretionary post-2001 sales to the DSIs. Berwager *et al*., WP-02-E-BPA-38, at 11.

<u>Evaluation of Positions</u>

Alcoa and Vanalco provide a summary of events that led to the negotiation of the "Block Sale Contracts" with the DSIs in 1996, and to BPA's offer of long-term transmission contracts allowing the DSIs to make non-Federal power purchases, which together appear to constitute the "accord and satisfaction" they reference. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 77-78. They note that most DSIs decided to sign a Block Contract, but that Alcoa and Vanalco elected to stay with their 1981 contracts and exercise their right to reduce their purchases from BPA under that contract. *Id*. at 78. Alcoa and Vanalco conclude that BPA's allocation proposal "is a breach of the covenant of good faith and fair dealing" because it deprives Vanalco and Alcoa of their benefits under the 1981 contract and the 1996 accord and satisfaction. *Id*. at 78.

BPA's allocation proposal in no way deprives Alcoa or Vanalco of any benefit or right under the 1981 contract. If they believe BPA has somehow breached that contract, or some duty of good faith and fair dealing, they are free to pursue those claims in the appropriate forums. Alcoa and Vanalco assert that BPA is punishing them through its allocation proposal for exercising their rights under the 1981 contract to reduce load on BPA. *Id*. However, given BPA's limited ability to provide the DSIs with an amount of power at below market prices, it is fair and reasonable to allocate that limited resource based on each DSI's commitment in 1995 to provide revenue certainty to BPA during the current rate period, enhancing BPA's continuing ability to bring long-term benefits to the region. Berwager *et al*., WP-02-E-BPA-38, at 11; Berwager *et al*., WP-02-E-BPA-09, at 8. At least one DSI customer indicated it would support the Compromise Approach agreement only if BPA allocated available power pursuant to this methodology.

See Cross-Examination Exhibit, WP-02-E-AL-32, at 3 ("Reynolds [Metals Company] supports the proposed amount of power for service to the DSIs, provided the power is allocated among the DSIs in the manner proposed by BPA.")

Nevertheless, Alcoa and Vanalco argue that BPA has provided no rationale for why the last five years of the 1981 contracts should receive 100 percent weighting and the first 15 years no consideration. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 87. To the contrary, while BPA has articulated its rationale for allocating a scarce benefit based on the level of IP-96 purchases placed on BPA by each DSI, Alcoa and Vanalco have failed to propose any reasonable alternative. Alcoa and Vanalco urge BPA to simply forget the level of past purchases by any company over any period, but to allocate available power based on each company's total plant load as a percentage of total sales to the DSIs. *See* Speer *et al*., WP-02-E-AL/VN/EG-01, at 15-17. This proposal is not supported by any rationale other than an argument that to do otherwise somehow violates their 1981 power sales contract rights and expectations, and that the DSIs that signed Block Sale Contracts were rewarded with stranded cost protections, and that rewarding them now with greater allocations is not appropriate. *Id*. at 12-15. Whether this is true or not, Alcoa and Vanalco continue to refuse to recognize the critical importance BPA placed in 1996 on retaining as much DSI load as possible at the IP-96 rate. Given the limited resource BPA can allocate to the DSIs at this time, it is not only reasonable but fair to allocate that limited resource recognizing the commitment made by each company to BPA at that time through the Block Sale Contracts.

In addition, their argument is irrelevant because whether the allocation methodology is "fair" is not a legal standard that applies to this decision. The Administrator has no obligation to offer either Alcoa or Vanalco a new section 5(d) contract for the post-2001 period. *See supra*, at 15.5.3. Even if she did, nothing in the Northwest Power Act, or any other BPA enabling statute, indicates that BPA would be required to meet each DSI's full requirements. Alcoa and Vanalco disagree, and suggest that each DSI's plant capacity is the appropriate allocator, citing the 1981 and 1996 contracts as support. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 78. Of course, the amount of power allocated to each DSI in its 1981 contract was fixed by section 5(d)(1)(B) of the Northwest Power Act to be equivalent to the amount of power each DSI was entitled to under its 1975 contract with BPA. These 1981 contracts were the mandatory initial long-term contracts that BPA was obligated to offer each DSI. However, allocations under section 5(d)(1)(A) are not dictated by section 5(d)(1)(B), which applied only to those initial contracts. Given that, a decision would still be required of the Administrator allocating whatever amount of power she could provide the DSIs consistent with BPA's other policy and ratemaking objectives and obligations. In effect, there is no law to apply to the allocation decision, because no provision in BPA's statutes limits the Administrator's discretion respecting allocations of post-2001 power to the DSIs under section 5(d)(1)(A). *Cf. City of Santa Clara v. Andrus*, 572 F.2d 660 (9^{th} Cir. 1978) (recognizing unfettered discretion in Secretary of Interior regarding allocation of Federal power to public preference customers absent specific statutory limitation on such discretion). In any case, as explained above, BPA believes its proposed allocation methodology is fair.

Finally, Alcoa and Vanalco assert that BPA's proposed allocation methodology is inconsistent with its stated goal to "ensure DSI survivability as a class." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 79. They argue that because they are being forced to go to the market for a substantial portion of their power needs (for Vanalco the amount is 97.5 percent) there is a substantially higher likelihood of Alcoa and/or Vanalco being forced to close its smelters during the rate period. *Id*. Alcoa and Vanalco have mischaracterized the nature of BPA's goals regarding DSI smelter survivability. BPA cannot guarantee the survivability of either any individual DSI or the DSIs as a class, and BPA never stated that was its goal. Berwager *et al*., WP-02-E-BPA-09, at 10. BPA's interest is in doing as much as it can to preserve DSI smelter jobs consistent with its other strategic goals and commitments. *Id*. at 11. BPA has a limited ability at this time to provide the DSIs with power at below-market rates. As a consequence, the Administrator is forced to make choices regarding how to allocate that limited resource among the members of the DSI class of customers.

The allocation methodology proposed by the Administrator attempts to balance the objective of offering some Federal power at below-market rates to each DSI, while recognizing the level of commitment made by each DSI in 1996 both to BPA's transition into the deregulated energy market and BPA's continuing ability to bring long-term benefits to the region. *Id*. at 8. Under BPA's proposed allocation methodology, Alcoa and Vanalco would receive a total of 230 aMW of below-market priced power, or roughly 16 percent of the total available to the DSIs, notwithstanding the fact that both Alcoa and Vanalco placed very little load on BPA in 1996 at the IP-96 rate. *Id*.

Decision

BPA is not required by the 1981 contracts, the so-called 1996 accord and satisfaction, or BPA's enabling statutes to allocate power to the DSIs based on plant capacity. BPA will use the allocation methodology based on each DSI's average annual purchases in the current rate period at the IP-96 rate.

16.0 SLICE OF THE SYSTEM PRODUCT

16.1 <u>Introduction</u>

Slice is a new and different product compared with BPA's more traditional requirements power products. It is important to understand the fundamental aspects of Slice product design, because the issues raised by the parties largely relate to the unique features of the product. The fundamental decisions regarding the product design were made in the Subscription Strategy and the Power Subscription Strategy ROD. A detailed description of the product design can be found in the above-referenced documents.

By design, Slice is a requirements power product sale, not a sale or lease of any part of the ownership of or operational rights to the FCRPS. Subscription ROD, at 85. Slice is a power sale based upon a Slice purchaser's annual net firm requirements load that is shaped to BPA's generation output from the FCRPS, rather than to the Slice purchaser's load. Mesa *et al.,* WP-02-E-BPA-32, at 2. The Slice purchaser will be entitled to a fixed percentage of the generation output from the FCRPS, based upon the size of the Slice purchaser's net firm requirements load. *Id.* The upper limit of the Slice percentage is determined by looking at the ratio of the customer's annual average net firm regional requirements load to the annual average FELCC of the FCRPS resources identified in the Slice contract. Wholesale Power Rate Development Study, WP-02-E-BPA-E-05, at 154. During certain periods of the year and under certain water conditions, the power delivered will exceed the customer's actual firm load. *Id.* As a consequence, Slice entails a sale of both net requirements and surplus power products. *Id.*

Eligibility for purchasing Slice is limited to PNW public preference customers as defined under section 5(b)(1) of the Northwest Power Act. 16 U.S.C. §839c(b)(1). Subscription ROD, at 89. By purchasing Slice, these public preference customers will forgo the right to have BPA serve their actual firm load in return for an energy product indexed to a percentage of the output from the FCRPS. *Id.* The IOUs and DSIs will not be eligible to purchase Slice. *Id.* Slice will be offered to the public preference customers on a contract basis of no less than 10 years. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 41.

Rather than paying a set price per MW for the power, Slice purchasers will assume the obligation to pay a percentage of BPA's costs proportionate to the percentage of the FCRPS that the Slice purchaser elects to purchase. *Id.* at 42. The costs considered by the Slice contract are referred to collectively as the Slice Revenue Requirement. *Id.* The Slice Revenue Requirement will be comprised of all the line items identified in the 2002 power rate case revenue requirement, with certain limited exceptions. Mesa *et al.*, WP-02-E-BPA-32, at 5. The exceptions to the PBL revenue requirement for Slice purchasers are:

- Transmission costs other than those associated with GTAs and with fulfilling System Obligations.

- Power purchase costs other than the net costs incurred as part of the Inventory Solution, which is discussed below.

- PNRR.

Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 155.

BPA has excluded these items from the Slice Revenue Requirement because these costs are not attributable to the Slice product. *Id.* at 155.

BPA is forecasting the need to increase or supplement the capability of the FCRPS, which is also referred to as the Inventory Solution. *Id.* at 156. The net costs associated with the Inventory Solution will become an obligation of the Slice purchaser. *Id.* The Slice purchaser will be responsible for a proportionate share of the net costs associated with the Inventory Solution. Mesa *et al.*, WP-02-E-BPA-32, at 13. However, the Slice purchaser will not receive any portion of the additional power. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 156.

The net cost of the Inventory Solution is estimated in the rate case and is not adjusted for actual expenses incurred for augmenting the system. Mesa *et al.*, WP-02-E-BPA-32, at 13. However, there will be an adjustment to the Inventory Solution for the actual MW necessary to augment the system after the close of the window for signing Subscription contracts. Mesa *et al.*, WP-02-E-BPA-54, at 11. Slice purchasers will be responsible for a proportionate share of that cost. *Id.* at 12. The manner in which the Inventory Solution shall be calculated for the Slice rate shall be through the Slice True-Up Adjustment Charge. The Slice True-Up Adjustment Charge is a monthly charge applied to the Slice product that is expressed in terms of dollars per percent Slice selected. The Slice True-Up Adjustment Charge consists of two components: (1) an Inventory Solution True-Up Adjustment that is calculated once for each rate period and is applied as a constant adjustment in each month of the rate period; and (2) the Annual Slice True-Up Adjustment that is calculated once each fiscal year and is applied to specific months of the fiscal year. In no event shall the Inventory Solution True-Up Adjustment exceed the net cost of the Inventory Solution.

One of the underlying principles of the Slice product design was that there would be no cost shifts either to or from the Slice purchasers. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 160. Slice was designed so that the overall financial impact would be revenue-neutral for all parties. *Id.* In order to determine whether offering Slice created cost shifts either to or from the Slice purchasers, BPA did a Cost Shift Study to ensure that the product was consistent with this underlying principle. *Id.*

The Cost Shift Study uses the same basic assumptions as the 2002 power rate case. Mesa *et al.*, WP-02-E-BPA-32, at 20. The first part of the Cost Shift Study compares the change in BPA's net revenues that would result from a customer switching from a requirements product purchase to a Slice product purchase. *Id.* at 20. This change in net revenues is independent of water conditions and therefore is referred to as the "Direct Revenue Impact." Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 161. The second part of the Cost Shift Study examines the change in BPA's net revenues from sales of secondary energy and power purchase costs resulting from delivering a share of BPA's secondary energy (surplus power) to the Slice purchaser. *Id*. The surplus power delivered to the Slice purchaser is the power BPA would otherwise have sold at market prices or used to displace its power purchases. *Id.* Since these revenue impacts vary, depending on water conditions, they are referred to as "Variable Revenue Impacts." *Id.*

The Cost Shift Study found that there was an average annual cost shift to Slice purchasers of $5.7 million as a result of BPA selling 15 percent of the generation output of the FCRPS as Slice. Wholesale Power Rate Development Study, WP-02-FS-BPA-05, Appendix C, Section 5.3. This cost shift is considered to be insignificant, given the margin of error in the Cost Shift Study assumptions and the relatively small size of the cost shift results. *Id.*

16.2 <u>Product Design</u>

16.2.1 <u>Introduction</u>

Slice is a requirements power product that sells a fixed percentage of the energy generated by the FCRPS to the public preference customers. The Slice product differs from traditional requirements products in that the power sold through Slice is shaped to BPA's generation output of the FCRPS rather than the purchaser's load. Because the Slice sale is a percentage of the generation output of the FCRPS, the actual deliveries of power will vary. During certain parts of the year and under certain water conditions, power deliveries will exceed the purchaser's net firm requirements. As a consequence, Slice entails both requirements and surplus power sales.

16.2.2 <u>Consistency of Slice with BPA's Statutory Obligations</u>

<u>Issue 1</u>

Whether BPA's decision to offer Slice is outside the scope of the 2002 power rate case.

<u>Parties' Positions</u>

Alcoa/Vanalco believe that by offering a percentage of the generation output of the FCRPS, in return for payment of an equal percentage of the PBL revenue requirement, BPA violated the Northwest Power Act, 16 U.S.C. §839 *et seq.*, and the Urgent Supplemental Appropriations Act of 1986, Public Law No. 99-349. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 54-55. Specifically, they contend that the sale is prohibited under the Northwest Power Act because Slice is designed to sell part of the Federal generation resources as opposed to the power produced by the FCRPS. *Id.* at 54.

Alcoa/Vanalco also believe that Slice is not an authorized sale under sections 5(b), (c), or (d) of the Northwest Power Act. *Id.* at 54-55. Specifically, Alcoa/Vanalco contend that Slice does not fit the definition of a net requirements sale under section 5(b), a Residential Exchange under section 5(c), or a sale to the DSIs under section 5(d). Alcoa/Vanalco contend that, in addition to violating various aspects of the Northwest Power Act, Slice violates the Urgent Supplemental Appropriations Act of 1986, Public Law No. 99-349. *Id.* at 55. According to Alcoa/Vanalco, Slice is a long-term lease of the Federal system that transfers to the Slice purchasers the ability to manage and control the operation of the generating facilities. *Id.* at 55. Alcoa/Vanalco contend that this long-term transfer of control violates the Urgent Supplemental Appropriations Act of 1986, Public Law No. 99-349. *Id.* at 55.

In Alcoa/Vanalco's brief on exceptions, they argue that the legality of the decision to offer Slice is a rate case issue. Alcoa/Vanalco Ex. Brief, WP-02-B-AL/VN-02, at 89. They contend that Slice is a rate for which a pricing formula must be established in the rate case. *Id.* As such, Slice is subject to challenge in the rate case. *Id.*

BPA's Position

Slice is a power product that BPA intends to offer as part of the Subscription Strategy. This rate proceeding is designed, in part, to establish a rate for the Slice product. BPA believes that the issues raised by Alcoa/Vanalco regarding the decision to offer Slice were issues either decided in the Subscription ROD or are subject to challenge after the execution of any Slice contract. In either case, the issues raised are outside the scope of this rate proceeding and are not subject to review in this ROD.

Even though the issues are outside the scope of this rate proceeding, Alcoa/Vanalco's arguments lack merit. Each of the three arguments relies primarily upon the contention that Slice is a sale or lease of the FCRPS resources that somehow transfers operational control of the system to the Slice purchaser. There is no factual basis for this contention. In the Wholesale Power Rate Development Study, WP-02-E-BPA-05, where the Slice product is described, it states unambiguously that "Slice is a sale of a fixed percentage of the generation capability of the FCRPS and is *not a sale or lease of any part of the ownership of, or operational control rights to, the FCRPS*." (Emphasis added.) Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 41.

Evaluation of Positions

Alcoa/Vanalco argue that BPA is prohibited by law from offering Slice to its public preference customers. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 54-55. Each of their arguments is premised upon their belief that Slice, by design, transfers a portion of the operational and managerial control of the Federal power system to the Slice purchaser. *Id.* at 54-55. Alcoa/Vanalco believe this transfer of control constitutes a violation of the Northwest Power Act, 16 U.S.C. §839 *et seq.*, and the Urgent Supplemental Appropriations Act of 1986, Public Law No. 99-349. *Id.* at 54-55.

Irrespective of whether Slice actually transfers some level of operational or managerial control of the Federal power system to the Slice purchaser, the resolution of this issue is a matter that is outside the scope of this rate proceeding.

The decision to offer Slice as a requirements product to BPA's public preference customers was made in the Subscription Strategy and the corresponding Subscription ROD. In the Subscription ROD, BPA explained the features of the Slice product and the rationale for BPA's decision to offer Slice. Part of the discussion in the Subscription ROD involved questions surrounding the potential for the sale or transfer of ownership or control of the FCRPS to the Slice purchaser. Subscription ROD, at 85. The Subscription ROD is clear that the sale of Slice does not entail the transfer of ownership or control of the FCRPS. The Subscription ROD states:

> Moreover, Slice does not sell any part of the ownership or the right to operation of the FCRPS to the purchaser. Control of the hydrosystem operation will continue to rest with the Federal agencies now charged with making operational decisions. Slice purchasers obtain only that power and service available based on the river conditions and reservoir operations BPA must implement for fish, flood control, or other considerations. BPA will not agree to any dispute resolution with Slice purchasers that could compromise decision making regarding fish and wildlife protection, or any other aspect of river operations.

Id.

Alcoa/Vanalco maintain that the unrebutted testimony and draft Slice contract demonstrate that BPA is transferring ownership, management, and control of the FCRPS to Slice customers. Alcoa/Vanalco Ex. Brief, WP-02-B-AL/VN-02, at 90. These arguments are without merit. One of the primary tenets of Slice was that it did not transfer ownership or operational control of the FCRPS to the purchaser of the product. Subscription ROD, at 85. There is substantial evidence on the record that demonstrates that ownership, management, and control of the FCRPS is not transferred with the purchase of Slice. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 41, 154.

While not all features of the Slice product had been determined at the time of the Subscription ROD, it was BPA's position that the sale of a net requirements product based on the generation shape of the FCRPS did not constitute a transfer of operational control or ownership of the FCRPS. *Id.* That decision in the Subscription ROD constituted a final action by the Administrator and as such, is subject to judicial review. 16 U.S.C. §839f(e)(1), (3), and (5).

Alcoa and Vanalco both challenged the legality of the Subscription ROD before the Ninth Circuit. *Goldendale Aluminum Company et al. v. BPA*, No. 99-70268 (9th Cir. 2000). However, the challenge by Alcoa and Vanalco focused on alleged violations of their constitutional first amendment and due process rights. Alcoa and Vanalco both elected not to raise any questions about BPA's decision to offer Slice. The Ninth Circuit Court of Appeals dismissed the case filed by Alcoa and Vanalco for lack of jurisdiction. *Goldendale Aluminum Company et al., v. BPA*, No. 99-70268 (9th Cir. 2000); Order dated February 9, 2000.

By failing to raise the issue before the Ninth Circuit, any objection Alcoa and Vanalco may have had with the decisions made in the Subscription ROD related to Slice are time-barred. 16 U.S.C. §839f(e)(5).

Having failed to raise the matter before the Ninth Circuit, Alcoa and Vanalco are now attempting to introduce a decision made in the Subscription ROD into this proceeding. The Federal Register

Notice outlined the scope of this proceeding. 64 Fed. Reg. 44318 (1999). Regarding matters resolved in the Subscription ROD, the Federal Register Notice states:

> The Administrator directs the Hearing Officer to exclude from the record any material attempted to be submitted or arguments attempted to be made in the hearing which seek to in any way revisit decisions that were made in BPA's Subscription Strategy, including the ROD for the Strategy.

Id. at 44322.

Clearly, the questions Alcoa and Vanalco are attempting to introduce are outside the scope of this proceeding as it is framed in the Federal Register Notice.

This is not to say that Alcoa and Vanalco are without a remedy. If BPA signs contracts with public preference customers for the sale of Slice, and Alcoa and Vanalco still believe the product, as set forth in the contract, is prohibited by statute, they would be able to make the appropriate legal challenge. 16 U.S.C. §839f(e)(1)(B), and (5).

In Alcoa/Vanalco's brief on exceptions, they contend that Slice is a rate or pricing formula which is being established in this proceeding, rather than a type of power product. Alcoa/Vanalco Ex. Brief, WP-02-B-AL/VN-02, at 89. Alcoa/Vanalco's argument attempts to confuse the distinction between a power rate and a power product. BPA is offering a variety of power products to its customers through the Subscription process. This rate proceeding will establish the rates for those various products. Slice, contrary to Alcoa/Vanalco's assertion, is not a rate or a pricing formula. Rather, it is a power product for which a rate is being established in this proceeding. As noted above, the decision to offer Slice was made in the Subscription Strategy and Subscription ROD.

<u>Decision</u>

BPA's decision to offer Slice is outside the scope of the 2002 power rate case.

<u>Issue 2</u>

Whether the Slice rate is consistent with section 7 of the Northwest Power Act.

<u>Parties' Positions</u>

Alcoa/Vanalco contend that BPA's decision to offer Slice is in violation of section 7 of the Northwest Power Act. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 54. Alcoa/Vanalco claim that because the Slice rate is a power rate for a product that contains both firm and surplus components, it violates section 7 of the Northwest Power Act. *Id.*

In its brief on exceptions, Alcoa/Vanalco contend that the Administrator's discretion in setting rates does not extend to the adoption of products not specified in the Northwest Power Act. Alcoa/Vanalco Ex. Brief, WP-02-B-AL/VN-02, at 90. Alcoa/Vanalco believe that BPA may establish rates only for "power sales enumerated by Congress." *Id.* Because Slice is not a sale "enumerated by Congress" in the Northwest Power Act, Alcoa/Vanalco contend the Administrator is proposing a "total elimination of the statutory rate directives" through Slice. *Id.* at 91.

<u>BPA's Position</u>

Nothing in the Northwest Power Act prohibits BPA's Administrator from establishing a single rate for a product that is comprised of both firm and surplus components. 16 U.S.C. §839e. BPA has considerable discretion under section 7 to set rates. This discretion allows the Administrator the ability to set rates to send customers price signals, as in the Slice rate.

The Administrator is not limited to setting rates for products that are specifically enumerated in BPA's organic statutes.

<u>Evaluation of Positions</u>

Alcoa/Vanalco contend that the Slice rate violates section 7 of the Northwest Power Act because it combines into a single rate both a requirements and a surplus power product. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 54. Alcoa/Vanalco provide no support for their interpretation of the statute.

Alcoa/Vanalco further contend that the Administrator may set rates only for products that Congress has enumerated in statute. Alcoa/Vanalco Ex. Brief, WP-02-B-AL/VN-02, at 91. Because Slice is a product not specifically enumerated in statute by Congress, Alcoa/Vanalco claim that the Administrator is abusing her discretion by establishing a rate for Slice. *Id.* Alcoa/Vanalco state that if the Administrator is allowed to develop a "whole new class of rates not authorized by Congress, the rate directives of §7 would be meaningless." *Id.*

BPA notes that the Administrator has broad discretion in establishing rates, and the Slice rate is consistent with the ratemaking standards established by the Northwest Power Act.

The Administrator has broad discretion to interpret and implement statutory standards applicable to ratemaking. These standards focus on cost recovery, and they do not restrict the Administrator to any particular rate design methodology or theory. *See Pacific Power & Light v. Duncan*, 499 F. Supp. 672 (D.C. Or. 1980); *accord City of Santa Clara v. Andrus*, 572 F.2d 660, 668 (9th Cir. 1978) ("widest possible use" standard is so broad as to permit "the exercise of the widest administrative discretion"); *ElectriCities of North Carolina v. Southeastern Power Admin*., 774 F. 2d 1262, 1266 (4th Cir. 1985). The United States Court of Appeals for the Ninth Circuit has also recognized the Administrator's ratemaking discretion. *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1120-29 (9th Cir. 1984).

The Slice rate is not inconsistent with section 7 of the Northwest Power Act because it blends into a single rate a requirements sale and a surplus power sale. Section 7(e) of the Northwest Power Act grants the Administrator considerable rate design discretion, including the ability to employ rate designs which recover BPA's costs through blended rates or pricing methodologies.

This broad discretion is found in section 7(e) of the Northwest Power Act, which provides:

> Nothing in this Act prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or *other rate forms*.

16 U.S.C. §839e(e) (emphasis added). The Ninth Circuit has recognized this authority, finding that "the statute does not require BPA to impose any particular type of rate on its customers. Rather it restricts BPA only to 'sound business principles' in setting rates to meet its revenue requirements." *City of Seattle v. Johnson*, 813 F.2d 1364, 1367 (9th Cir. 1987). Thus, the Administrator's primary ratesetting obligation is to set rates to meet BPA's revenue requirements, consistent with sound business principles. *See* 16 U.S.C. §839e(a)(1).

In *Central Lincoln Peoples' Utility District. v. Johnson*, 735 F.2d 1101 (9th Cir.1984), the Court noted that the Northwest Power Act "specifically allows the Administrator latitude in choosing rate forms" and has, as a main purpose, encouraging "conservation and efficiency." *Id*. at 1122. 16 U.S.C. §839e(e) and 16 U.S.C. §839(1). The point of such ratemaking is to "encourage efficiency and conservation by enabling customers to make informed consumption decisions based on the costs of producing each type of electric power." *Id*. at 1121. This is exactly the same logic used to develop the rate for Slice. Despite Alcoa/Vanalco's assertions to the contrary, it is a proper exercise of statutory ratemaking authority that "permits rate forms designed to give BPA customers price signals." *Id*. at 1122 (H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. (1980) at 53).

Alcoa/Vanalco's argument that the Administrator is limited to setting rates only for products enumerated by Congress is equally without support. Alcoa/Vanalco's argument is premised on the idea Slice is a product not specifically enumerated by Congress and therefore, the Administrator is prohibited from establishing a rate for the product. There is, however, no specific limitation in the Northwest Power Act, or any of the other ratesetting directives, that limits BPA's ability to design and offer a variety of products. The Northwest Power Act is silent regarding product design features and the types of products BPA can offer. BPA has traditionally designed power products to meet the needs of its customers. This flexibility has allowed BPA not only to meet the needs of its customers and but also to meet its financial obligations. Alcoa/Vanalco's argument would limit BPA's ability to design and offer products to some undefined categories. As noted above, section 7 of the Northwest Power Act gives the Administrator a great deal of flexibility to set rates for new products.

Decision

The Slice rate is consistent with the ratemaking directives in section 7 of the Northwest Power Act.

Issue 3

Whether BPA's offer of the Slice product complies with NEPA.

Parties' Positions

Alcoa/Vanalco contend that prior to making Slice a product available under Subscription, BPA was required to conduct an Environmental Assessment (EA) to determine whether an EIS was necessary. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 56. Alcoa/Vanalco state that by failing to perform an EA or issue an EIS, BPA failed to comply with NEPA and ignored the significant environmental impacts on the FCRPS that will result from offering Slice. *Id.* at 57. According to Alcoa/Vanalco, Slice purchasers may use the surplus portion of the Slice purchase to displace more expensive resources. *Id.* at 57-58. Alcoa/Vanalco state that this may result in the curtailment or closure of nonsystem power generating facilities, causing significant environmental impacts. *Id.* at 58. Alcoa/Vanalco contend that Slice will, in addition to potentially causing the curtailment or closure of generation facilities, allow purchasers to change the flow of the river and operation of the dams, causing a direct impact on the environment. *Id.* at 58.

In their brief on exceptions, Alcoa/Vanalco contend that "BPA does not dispute that Slice triggers the environmental assessment requirements of NEPA" and "that the environmental impacts alleged by Alcoa and Vanalco may occur." Alcoa/Vanalco Ex. Brief, WP-02-B-AL/VN-02, at 91. Alcoa/Vanalco state that BPA's attempt to tier the Subscription Strategy and Subscription ROD to the BP EIS was in error, because Slice was a program not even proposed at the time the BP EIS was drafted. *Id.* at 92. Alcoa/Vanalco acknowledge that this fact is not fatal to BPA's NEPA compliance, but they contend that the NEPA ROD was flawed because it did not adequately analyze Slice. *Id.* at 93. Alcoa/Vanalco believe that they do not need to show any change in circumstances between the issuance of the BP EIS and issuance of the Subscription ROD. They contend that Slice is such a different product that it changed the environmental circumstances. *Id.*

BPA's Position

In December 1998, BPA issued the Subscription Strategy and Subscription ROD. These documents addressed, in part, BPA's decision to offer Slice, and outlined the design features of the product. Subscription ROD, at 81-109. In addition to the Subscription Strategy and Subscription ROD, BPA also issued the NEPA ROD. The NEPA ROD relied upon the BP EIS for the analysis of the environmental consequences of BPA's proposed actions in the Subscription Strategy and Subscription ROD. NEPA ROD, at 15-22. The NEPA ROD found the environmental impacts from BPA's Subscription Strategy were adequately covered in the BP EIS. NEPA ROD, at 22. While the BP EIS was issued well before the decision to offer Slice, the BP EIS was designed to support a number of subsequent decisions, including the Subscription Strategy. BP EIS, at 1-5, 1-7.

BPA believes that questions regarding its compliance with NEPA were decisions made in the NEPA ROD. To the extent that NEPA ROD failed to comply with the NEPA by not properly addressing the environmental consequences of the final decisions made in the Subscription Strategy and the Subscription ROD, those concerns should have been raised before the Ninth Circuit Court of Appeals. By failing to appeal this final action, the matter is time barred.

Evaluation of Positions

Alcoa/Vanalco's argument is founded on the fact that BPA issued the BP EIS well before the decision to offer Slice was ever considered. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 58. Because of the sequence of these two events, Alcoa/Vanalco contend that BPA cannot rely upon the BP EIS, as it did in the NEPA ROD, as a basis for fulfilling its NEPA obligations. *Id*. at 56. Implicit in the argument is the contention that BPA cannot rely on a comprehensive programmatic impact statement such as the BP EIS and must perform a contract-specific EIS before offering Slice to public preference customers.

In their brief on exceptions, Alcoa/Vanalco contend that the NEPA ROD did not adequately address the environmental consequences of Slice. Because there were limited references to Slice in the NEPA ROD, Alcoa/Vanalco believe that BPA has not met its environmental obligations under NEPA.

Alcoa/Vanalco incorrectly assume BPA cannot rely on the BP EIS to fulfill BPA's obligations under NEPA. The fact that the BP EIS (June 1995) was issued several years prior to the decision in the Subscription ROD (December 1998) to offer Slice does not automatically make the decision to rely on the prior environmental impact statement inconsistent with BPA's NEPA requirements. The BP EIS was designed to provide BPA with a comprehensive impact statement that would allow BPA to respond to the changes in the marketplace. Business Plan ROD, at 1. "Other decisions on specific issues will be the subject of subsequent RODs that will be tiered to this ROD and distributed to the public. For example, while this ROD provides general direction on rate policies, decisions on how policies will be applied in the 1996 rate case will be applied in a tiered ROD. The BP EIS will sufficiently document the analysis needed for a variety of these business decisions." *Id.* at 14. As further explained the BP EIS:

> This BP EIS is a programmatic EIS: that is, it addresses 'umbrella' policies and concepts. Approaches, strategies, and general agency direction--not site-specific actions--are recommended here. As the Administrator implements his broader policies and business strategies, other more specific business decisions such as the development of individual energy generation resources and transmission facilities will have their own environmental review and decision process. These additional environmental reviews will look at site-specific actions, using the information and decision in this EIS as a base to understand how they fit into the more global policies and business strategies. This process is called 'tiering' where more specific additional information on potential environmental consequences adds to the understanding for subsequent decisions (where more specific information on environmental consequences does not improve decisions or segments the decisions by focusing on only small pieces which lose sight of the cumulative concerns, then no more environmental analysis is conducted).
>
> The EIS is intended to support the following decisions:
>
> - A business concept BPA will adopt, with response strategies for changing circumstances;

- Products and services BPA will market;

- Rates for BPA products and services to be implemented in the 1995 and 1996 rate cases and future rate cases;

- A strategy BPA will use to administer its fish and wildlife responsibilities;

- Policy direction for BPA's sale of power products to publicly owned utilities, IOUs, DSIs, and non-utility purchases, and for Residential Exchange agreements with PNW utilities;

- Contract terms BPA will offer for power sales to PNW publicly owned utilities, IOUs, DSIs, and IPPs for transmission services; and for extraregional sales, including non-PNW IPPs/broker/marketers;

- Plans for BPA resource acquisitions (including renewables, conservation, and thermal) and power purchase contracts;

- A policy for transmission system access and development.

> Before taking action, BPA will review the decisions listed above to ensure that they are adequately covered within the scope of alternatives and impacts described in the BP EIS.

BP EIS, at 1-5 to 1-7.

The NEPA ROD stated that "A review of the BP EIS clearly shows that the potential environmental impacts from BPA's Power Subscription Strategy are adequately covered." NEPA ROD, at 16. The NEPA ROD analyzed the potential air, land, water, and socioeconomic effects of the Subscription Strategy in the context of the BP EIS and found the Subscription Strategy to be consistent with the decision and strategy laid out in the BP EIS. *Id*. at 16-22. This analysis included the decision to offer Slice to BPA's public preference customers. Subscription ROD, at 89-90.

BPA's decision to tier its subsequent RODs to the BP EIS has been supported by the Ninth Circuit. In *APAC v. BPA*, the court found that BPA's reliance on the BP EIS obviated the need for a subsequent site- or project-specific EIS. *APAC v. BPA*, 126 F3d 1158, 1183 (9th Cir. 1997). In *APAC*, the petitioners challenged BPA's decision to offer the DSIs cost protection in the Block Sale contracts. *Id.* The petitioners argued that BPA could not tier the ROD for these contracts to the BP EIS, but rather, BPA was required to issue a separate EIS for each contract. *Id.* at 1184. The court rejected the petitioners' argument and found that tiering the ROD to the BP EIS was consistent with NEPA. *Id.* The court went on to find that a comprehensive programmatic environmental impact statement was superior to a contract-specific one, because the former examines the entire range of policy issues rather than engaging in a piecemeal analysis. *Id.* The court further found that the mere passage of time would not cause the EIS to become outdated.

Id. A significant change in circumstances between issuance of the programmatic EIS and the ROD is necessary to trigger the need for a new or supplemental EIS. *Id*.

The impact of the Ninth Circuit's decision in *APAC* is fourfold. First, the decision establishes that it was appropriate to tier a later ROD to a prior programmatic EIS. Second, Alcoa/Vanalco have not demonstrated any intervening change of circumstances that would necessitate supplementing or issuing a new EIS. Third, the NEPA ROD constitutes a final action by the Administrator, and by failing to challenge the action, Alcoa/Vanalco waived any objection. Finally, the Federal Register Notice specifically determined that issues related to the Subscription Strategy were beyond the scope of the 2002 power rate case proceeding.

Alcoa/Vanalco's contention that Slice had to be contemplated at the time the BP EIS was drafted in order for it to satisfy the environmental analysis under NEPA demonstrates a fundamental lack of understanding of the requirements of the statute. A programmatic EIS, by design, does not address contract-specific issues, but rather it is designed to address a broad range of policy issues. The BP EIS was designed to provide BPA with a programmatic environmental impact statement that could address decisions to offer new and different products and contracts to its customers. As with the Slice product, the Block Sales offered to the DSIs in the *APAC* case were not contemplated at the time the BP EIS was drafted. Despite this fact, the court determined that the environmental consequences of decision to offer the Block contract was covered by the BP EIS.

The NEPA ROD also constituted a final action by the Administrator and as such, is subject to judicial review. 16 U.S.C. §839f(e)(1), (3), and (5). Alcoa and Vanalco both challenged the legality of the Subscription ROD (which incorporated the NEPA ROD) before the Ninth Circuit. *Goldendale Aluminum Company et al. v. BPA*, No. 99-70268 (9th Cir. 2000). However, the challenge by Alcoa and Vanalco focused on alleged violations of their constitutional first amendment and due process rights. Alcoa and Vanalco both elected not to raise any questions about BPA's decision to offer Slice or the adequacy of BPA's compliance with NEPA. The Ninth Circuit Court of Appeals dismissed the case filed by Alcoa and Vanalco for lack of jurisdiction. *Goldendale Aluminum Company et al. v. BPA,* No. 99-70268 (9th Cir. 2000); Order dated February 9, 2000.

By failing to raise the issue before the Ninth Circuit, any objection Alcoa and Vanalco may have had to the decisions made in the Subscription ROD or the NEPA ROD related to Slice are time barred. 16 U.S.C. §839f(e)(5).

Having failed to raise the matter before the Ninth Circuit, Alcoa and Vanalco are now attempting to introduce the matter into this proceeding. The Federal Register Notice outlined the scope of this proceeding. 64 Fed. Reg. 44318 (1999). Regarding matters resolved in the Subscription ROD, the Federal Register Notice states:

> The Administrator directs the Hearing Officer to exclude from the record any material attempted to be submitted or arguments attempted to be made in the hearing which seek to in any way revisit decisions that were made in BPA's Subscription Strategy, including the ROD for the Strategy.

Id. at 44322.

Decision

The decision to offer Slice to BPA's public preference customers was made consistent with BPA's statutory obligations under NEPA, but the matter is outside the scope of the 2002 power rate case.

Issue 4

Whether BPA's decision not to offer Slice to the IOUs is a matter within the scope of the 2002 power rate case.

Parties' Positions

The IOUs contend that they should be offered Slice. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 63. The IOUs claim that the decision to offer Slice only to BPA's public preference customers violates BPA's obligation under section 7 of the Northwest Power Act to offer rates of general applicability to the residential and small farm customers of the IOUs. *Id.*

In IOUs' brief on exceptions, they repeat their contention that BPA's decision not to offer Slice to the IOUs is a violation of section 7 of the Northwest Power Act and section 9 of the Transmission System Act. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 46. The IOUs believe that it is arbitrary and capricious to rely upon the Subscription ROD as a basis for excluding consideration of this issue in this proceeding. *Id.* at 47. The IOUs contend that the Administrator cannot avoid the statutory ratesetting requirements that are part of this proceeding by asserting that the decision on the eligibility of the IOUs to purchase Slice was made in another forum. *Id.*

The IOUs also believe they have not waived any right to contest this issue by failing to appeal the issue in the Ninth Circuit Court of Appeals. *Id.* at 48. The IOUs contend that the matter may still be appealed to the Ninth Circuit and that their failure to raise this issue before the Ninth Circuit is factually incorrect, because the Ninth Circuit dismissed the matter on jurisdictional grounds before the IOUs submitted a statement of the issues. *Id.* at 49.

BPA's Position

The decision to sell Slice only to BPA's public preference customers was made in the Subscription Strategy and the corresponding Subscription ROD and is therefore beyond the scope of the issues in this rate proceeding. Subscription ROD at 88-90; 64 Fed. Reg. 44318, 44322 (1999).

Evaluation of Positions

Whether the decision to limit the eligibility to purchase Slice constitutes a violation of section 7 of the Northwest Power Act or section 9 of the Transmission System Act as alleged by the IOUs is a matter that is beyond the scope of this proceeding. The decision to offer Slice as a requirements product to BPA's public preference customers was made in the Subscription

Strategy and the corresponding Subscription ROD. Subscription Strategy, at 14; Subscription ROD, at 81-109. In the Subscription ROD, BPA explained the features of the product and the rationale for BPA's decision to offer Slice. *Id.* The issue of whether the IOUs would be offered a Slice product was squarely addressed in the Subscription ROD. *Id.* at 88-90. In the Subscription ROD, it was determined that BPA would not offer Slice to any customer class other than BPA's public preference customers. The reasoning for that decision was explained in the Subscription ROD. *Id.*

The decision in the Subscription ROD constituted a final action by the Administrator and as such, is subject to judicial review. 16 U.S.C. §839f(e)(1), (3), and (5). Failure to appeal a final decision by the Administrator is time barred if not raised within 90 days of the final action. 16 U.S.C. §839f(e)(5). The IOUs are now attempting to introduce a decision made in the Subscription ROD into this proceeding. The Federal Register Notice outlined the scope of this proceeding. 64 Fed. Reg. 44318 (1999). Regarding matters resolved in the Subscription ROD, the Federal Register Notice states:

> The Administrator directs the Hearing Officer to exclude from the record any material attempted to be submitted or arguments attempted to be made in the hearing which seek to in any way revisit decisions that were made in BPA's Subscription Strategy, including the ROD for the Strategy.

Id. at 44322.

Clearly, the question the IOUs are attempting to introduce is outside the scope of this proceeding, as it is framed in the Federal Register Notice. In their brief on exceptions, the IOUs contend that their appeal rights to the Ninth Circuit have not been waived by their failure to address this issue sooner. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 48-49. Whether the IOUs' right to appeal has been waived is not a matter within scope of this Record of Decision, nor is it within the Administrator's authority to make such a determination. Ultimately, a decision as to whether the IOUs have waived their appeal rights on this issue will be made by the Ninth Circuit, if the IOUs choose to raise this matter before the court.

Decision

BPA's decision not to offer Slice to the IOUs is a matter that is beyond the scope of the issues in the 2002 power rate case.

16.3 Transmission

Issue 1

Whether Slice purchasers will pay twice for transmission losses if the amount of Slice offered is capped or limited.

Parties' Positions

SPG argued in its direct case that BPA's Slice Revenue Requirement should be reduced so that Slice purchasers do not pay twice for transmission losses. Carr *et al*., WP-02-E-SG-01, at 26. In its initial brief, however, SPG agreed with BPA's rebuttal testimony that the adjustments were not necessary, because the manner in which losses on the system are calculated fully accounts for transmission losses without any double collection. SPG Brief, WP-02-B-SG-01, at 18-19. SPG states, however, that if BPA limits or caps the amount of Slice it offers, Slice purchasers will pay twice for transmission losses. *Id.* at 19. They contend this will occur because a limit or cap will not allow the Slice purchaser to "obtain the extra power made available through the adjustment of FELCC for transmission losses." *Id.*

BPA's Position

In rebuttal, BPA stated that Slice purchasers were not paying twice for transmission losses. Mesa *et al*., WP-02-E-BPA-54, at 14-15. The FELCC of the Federal system used in the initial proposal was reduced to account for system transmission losses. *Id.* To determine the maximum percentage of the system generation a Slice purchaser is eligible to buy, the Slice purchaser's annual net requirements are divided by the FELCC, less system losses. *Id.* Losses are factored into the calculation, ensuring that Slice purchasers do not pay twice. *Id.* If a Slice purchaser buys less than its full net requirements as Slice, or a cap or limit is placed on the amount of Slice available, there is no impact on the treatment of losses.

The decision to cap or limit the amount of Slice is not an issue in this rate proceeding. There is a separate public process dealing with the decision to limit or cap the amount of Slice offered. Tr. 1344. To the extent that a limit or cap is placed on the amount of Slice BPA makes available, that decision will be made in that public process and not in this rate case. If, at the conclusion of the public process, the amount of Slice made available to purchase is limited, transmission losses will not be collected twice, because a Slice purchaser's percentage of the system would still be calculated in the same fashion. The denominator in the above-referenced equation would still be the FELCC less transmission losses, ensuring that losses are not collected twice. Mesa *et al*., WP-02-E-BPA-54, at 14-15.

Evaluation of Positions

A Slice purchaser would have two basic purchase options. The Slice purchaser could make an economic decision to purchase all of its net requirements as Slice. By making this decision, a Slice purchaser would purchase the maximum percentage of Slice allowed, and would be required to declare resources to serve the balance of its net requirements. Subscription ROD, at 84. The other alternative would be for the Slice purchaser to purchase part of its net requirements as Slice. The Slice purchaser could voluntarily combine Slice with a Block purchase. *Id.* at 92-93. Under this option, the Slice purchaser would serve a portion of its load with Slice at some percentage less than the maximum allowed. The balance of the Slice purchaser's net requirements would consist of a Block purchase and additional resources to serve the balance of its net requirements. *Id.* at 84. Under either scenario, transmission losses are deducted from the FELCC prior to determining the percentage of Slice purchased. Mesa *et al*., WP-02-E-BPA-54, at 14-15.

SPG agreed with BPA that if transmission losses are deducted from the FELCC before determining the maximum percentage a Slice purchaser is eligible to purchase, there is no double collection of transmission losses. SPG Brief, WP-02-B-SG-01, at 18-19. Despite general agreement on the subject, the SPG argued that if the amount of Slice product available to public preference customers is capped or limited, Slice purchasers will pay twice for transmission losses. *Id.* at 18. This would occur, SPG contends, because "if Slice purchasers cannot purchase their full Slice Percentage, they will not obtain the extra power made available through the adjustment to the FELCC for transmission losses." *Id.* at 19. SPG provides no substantive analysis to support this conclusion.

SPG's argument on this point appears to be inconsistent with its own testimony. The SPG claims, on one hand, that Slice purchasers are paying twice for transmission losses if Slice is limited or capped. *Id.* Yet SPG acknowledges that absent some limit or cap on the amount of Slice available, there is no double collection of transmission losses, because the losses are deducted from the FELCC before the maximum percentage is determined. *Id*. The only factual difference between the two circumstances would be that rather than voluntarily taking less than the maximum percentage available, there is a limit imposed by BPA on the amount purchased. In either case, the treatment of transmission losses would be the same, as would be the impact on the Slice purchaser.

There is no reason that transmission losses will be double collected in the event that there is some limit or cap. The calculation of the percentage of the Federal system generation which the Slice purchaser is buying will be the same. Transmission losses will be deducted from the FELCC prior to the calculation of the percentage of Slice purchased, whether or not there is a limit or cap on the amount available. The only difference is that the limit would be imposed by BPA, rather than chosen by the Slice purchaser.

However, any decisions regarding limiting or capping the amount of Slice available to public preference customers are not part of this proceeding. Those issues are being addressed in a separate public process. Tr. 1344. In the event that limits are placed on the amount of Slice available, questions regarding the impact of limiting the amount available on the payment for transmission losses should be posed in that public process.

Decision

Slice purchasers will not be charged twice for transmission losses in the event they purchase less than a maximum percentage of Slice or if the amount of Slice is limited or capped.

Issue 2

Whether costs associated with transmission activities of the PBL should be removed from the Slice Revenue Requirement to avoid double collection of such costs by BPA.

Parties' Positions

The MAC argues that BPA should remove costs associated with transmission activities of the PBL from the power scheduling costs allocated to the Slice product. MAC Brief, WP-02-B-MA-01, at 10. MAC contends that Slice purchasers will bear the costs associated with transmission activities of the PBL through their transmission rates, which will be determined in the upcoming BPA transmission rate case. *Id.* at 10. MAC argues that this represents a double collection of such costs if they are included in the Slice Revenue Requirement. *Id.* at 10.

BPA's Position

Costs associated with transmission activities of the PBL will not be included in the costs allocated to BPA's transmission rates. Pedersen and McRae, WP-02-E-BPA-28, at 1-8. Furthermore, should there be such a cost that should be shared between BPA's PBL and TBL, but by mutual agreement that cost is allocated in full to the PBL, PBL will charge the TBL for its share of that cost, and the payment from TBL would be appropriately accounted for as a credit in PBL's revenue requirement. *Id*. Correspondingly, this credit would be reflected in the Slice Revenue Requirement. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 157-158.

Evaluation of Positions

MAC argues that Slice purchasers will be paying twice for certain costs associated with transmission activities of the PBL, if these costs are not removed from the Slice Revenue Requirement. MAC Brief, WP-02-B-MA-01, at 10. MAC contends that unless removed, certain costs will be collected through both BPA's transmission rates and the Slice Revenue Requirement. *Id.* MAC does not identify what costs are part of both the transmission rates and Slice Revenue Requirement.

MAC's argument is factually incorrect. BPA has specifically removed all costs related to transmission activities, except for those associated with System Obligations and GTAs, from the Slice Revenue Requirement. Mesa *et al.*, WP-02-E-BPA-54, at 13. No costs associated with transmission activities of the PBL will be included in the costs allocated to BPA's transmission rates. Pedersen and McRae, WP-02-E-BPA-28, at 1-8. The costs associated with transmission activities of the PBL are power marketing expenses associated with procuring transmission service for particular power products. They are correctly functionalized to generation and included in generation revenue requirements, not transmission revenue requirements. Revenue Requirement Study, WP-02-E-BPA-02, at 63. Therefore, Slice purchasers will not be paying twice for such costs.

Decision

The Slice Revenue Requirement reflects the appropriate costs that the Slice purchasers should be responsible for, and there are no costs associated with transmission activities of the PBL that are allocated to BPA's transmission rates.

16.4 Slice Revenue Requirement

16.4.1 Minimum Net Revenue Requirement

Issue

Whether to ensure consistency with the revenue requirements of other products and to avoid the possibility of a cost shift to non-Slice purchasers, it is necessary to modify the Slice true-up for capital cost recovery to the greater of PBL's non-cash expenses or amortization and irrigation assistance payments.

Parties' Positions

SPG argued that rather than having the Slice Revenue Requirement trued-up to BPA's depreciation expense, as was suggested in BPA's direct case, the true-up should be based on the greater of amortization or depreciation. In those years when the amortization payment exceeds depreciation expense, the excess would be recovered through the true-up. Carr *et al.*, WP-02-E-SG-01, at 25.

BPA's Position

Capital investments are recovered through depreciation, and depreciation is part of the annual true-up. Mesa *et al.*, WP-02-E-BPA-54, at 9.

Evaluation of Positions

No party, including SPG, raised this issue. However, after careful consideration of the issue, it became apparent that there was the potential for a cost shift under certain circumstances if BPA's initial proposal was adopted for the final rates. By using only depreciation as the mechanism for the annual recovery of capital investments, BPA may fail to fully recover its actual costs under the same conditions that necessitate adding funds to the generation revenue requirement to avoid a cash shortfall in a particular year. SPG's proposal to use the greater of amortization or depreciation, while similar in concept to the decision in this ROD, also does not ensure full cost recovery or ensure no cost shift, because of the manner in which BPA accounts for these costs in the generation revenue requirement.

BPA's Revenue Requirement Study, WP-02-E-BPA-02, produces the total generation revenue requirement necessary for BPA to meet its annual financial obligations. The basis for BPA's generation revenue requirement is total annual generation expenses, which include items related to capital cost recovery that do not require outlays of cash in that year (non-cash expenses). Revenue Requirement Study, WP-02-E-BPA-02, at 38-39. These capital cost recovery items (non-cash expenses) are: Federal Projects Depreciation, Amortization of Conservation and Fish and Wildlife Investments, and the Capitalization Adjustment. *Id.* at 40.

In order to ensure full annual cost recovery, BPA must determine whether it is necessary to add funds to cover those cash payments that are not directly included in revenue requirements.

Id. at 38-39. Minimum Required Net Revenues is the component of the generation revenue requirement that, when combined with the non-cash expenses, ensures there is sufficient cash to cover planned amortization and irrigation assistance payments. *Id*. If the non-cash expenses do not cover these cash payments, the difference is added to the revenue requirement so that cash considerations will be met by revenues in that year. *Id*. In the FY 2002-2006 rate period, the revenue requirements for 2005 and 2006 include forecasted amounts for Minimum Required Net Revenues. *Id.* at 47.

The Slice Revenue Requirement is a subset of the generation revenue requirement. There are discrete elements that are excluded from the generation revenue requirement to produce the Slice Revenue Requirement. Mesa *et al.,* WP-02-E-BPA-32, at Attachments 1 and 2. The Slice Revenue Requirement will have an annual true-up that will calculate the difference between the forecasted Slice Revenue Requirement and actual expenses and credits. Mesa *et al.,* WP-02-E-BPA-32, at 9. BPA's proposed capital investments will be recovered through depreciation expense. Mesa *et al.,* WP-02-E-BPA-54, at 9. Minimum Required Net Revenues are not part of the Slice Revenue Requirement, so there is no mechanism for ensuring that there is sufficient cash to ensure payment of planned amortization and irrigation assistance. Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 105-06. SPG made an alternative proposal that "[i]n those years when actual amortization expenses exceed actual depreciation expenses, the excess would be recovered through the True-Up. In those years when the reverse occurs, no adjustment is necessary in the True-Up." Carr *et al.*, WP-02-E-SG-01, at 25.

This proposal, while principally sound, does not capture fully the considerations that BPA uses to ensure the adequacy of funds for amortization/irrigation assistance payments. As noted above, one of the non-cash expenses included in BPA's generation revenue requirement is the Capitalization Adjustment, a negative component of Net Interest Expense. Revenue Requirement Study, WP-02-E-BPA-02, at 37-38. Similarly, BPA does not include amortization/irrigation assistance directly in its generation revenue requirement. Rather, the generation revenue requirement includes a reference to Minimum Required Net Revenues. This item accounts for the amount by which all of the non-cash expenses may be exceeded by planned amortization and irrigation assistance. *Id*. at 39.

BPA stated in its testimony that the "Slice product, by design, is attributed with the same costs for its revenue requirement as the other products." Mesa *et al.*, WP-02-E-BPA-32, at 5. This would not be the case if BPA's initial proposal is adopted. Under BPA's initial proposal, there is no Minimum Required Net Revenues that is part of the true-up. Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 105-06. As previously referenced, there are years (2005-2006) in which BPA's forecasted generation revenue requirement includes Minimum Required Net Revenues to cover the cash requirement for amortization and irrigation assistance payments. Revenue Requirement Study, WP-02-E-BPA-02, at 47.

The SPG proposal parallels on an actual basis the conditions addressed by Minimum Required Net Revenues. However, the comparison between depreciation expense (Federal Projects Depreciation and Amortization of Conservation and Fish and Wildlife Investments) and amortization payments (including irrigation assistance) falls short of ensuring adequate coverage for all cash payments. The other non-cash expense, the Capitalization Adjustment, which is a negative component of interest expense, must also be taken into account. As previously described, all non-cash expenses must be weighed against amortization and irrigation assistance payments to ensure sufficient coverage of these cash requirements. *Id.*

In order to have the Slice Revenue Requirement comport with the generation revenue requirements for other Subscription products, the Slice Revenue Requirement and, more importantly, the true-up to actual costs should include a Minimum Required Net Revenues component. This will ensure sufficient funds to cover the cash payments for debt reduction from which Slice purchasers, as well as other purchasers of Subscription products, will benefit.

One of the fundamental tenets of Slice is that the product would be designed in such a fashion that there would not be cost shifts to or from Slice purchasers from or to BPA's other customers. If the proposal advocated by BPA, in its testimony, were adopted, the potential for a cost shift to BPA's non-Slice purchasers would exist. If BPA trued-up the Slice Revenue Requirement and did not include a Minimum Required Net Revenues component, a cost shift would occur in those years when non-cash expenses do not cover these cash payments. Therefore, to avoid the possibility of a cost shift, a Minimum Required Net Revenues component should be added to the actual Slice Revenue Requirement.

<u>Decision</u>

To ensure consistency with the revenue requirements for other products, thereby avoiding any cost shift in this area, the Slice True-Up for capital cost recovery has been modified to be the greater of PBL's non-cash expenses or amortization and irrigation assistance payments.

16.4.2 <u>Power Marketing Costs</u>

<u>Issue</u>

Whether BPA should remove the costs associated with BPA's power marketing from the Slice Revenue Requirement.

<u>Parties' Positions</u>

MAC argues that most of BPA's power marketing costs should be removed from the Slice Revenue Requirement. MAC Brief, WP-02-B-MA-01, at 10. MAC claims that the costs associated with sales of other products, managing short-term purchases and sales, and other such power costs are costs the Slice purchaser assumes independently, and they should be removed from the Slice Revenue Requirement. *Id.*

<u>BPA's Position</u>

BPA has attempted to segregate the costs associated with BPA's power marketing activities and remove them from the Slice Revenue Requirement. Mesa *et al.*, WP-02-E-BPA-54, at 12. BPA made some policy decisions in developing the Slice product, one of which included a decision not to conduct a detailed accounting of certain items such as salary and overhead expenses, to determine with absolute precision the costs that should be excluded from the Slice Revenue Requirement. *Id.* While BPA has agreed to continue to refine its accounting practices to further identify costs that should be excluded from the Slice Revenue Requirement, there will be a point beyond which BPA may not be able to segregate such costs. *Id.*

Evaluation of Positions

MAC contends that power marketing costs should be removed from the Slice Revenue Requirement. MAC Brief, WP-02-B-MA-01, at 10. MAC's argument describes in very broad terms the types of costs it believes should be excluded from the Slice Revenue Requirement. *Id*. MAC notes that "[c]osts associated with managing transmission purchases and sales, negotiating new surplus power sales contracts, and managing secondary energy sales from the Federal system are the types of costs that the Slice product description excludes by definition." *Id*. at 10. However, before MAC raised this issue in its brief, BPA testified that power marketing costs would not be included in the Slice Revenue Requirement. Mesa *et al.,* WP-02-E-BPA-54, at 12. There is general agreement on the issue and the dispute, if any, appears to be over the level of detail to which one should go to segregate the costs into separate categories.

BPA believes that power marketing costs have been appropriately excluded from the Slice Revenue Requirement, with the limited exception of salary and overhead expenses associated with these activities. *Id.* BPA has attempted to account for program level expenses and include only those associated with Slice. *Id.* BPA will continue to refine its accounting practices to properly segregate costs and will reflect any adjustments in the annual true-up. *Id.*

Decision

BPA believes that power marketing costs have been appropriately excluded from the Slice Revenue Requirement, with the potential limited exception of some specific salary and overhead expenses associated with these activities.

16.4.3 Hedging Costs

Issue

Whether BPA should remove all non-Slice hedging costs from the Slice Revenue Requirement.

Parties' Positions

SPG argues that BPA should remove from the Slice Revenue Requirement all hedging costs not associated with the Slice product. SPG Brief, WP-02-B-SG-01, at 18. SPG contends that hedging costs should be removed because these costs benefit only non-Slice customers. *Id.*

MAC also argues that BPA should remove all costs associated with BPA's risk hedging program. MAC Brief, WP-02-B-MA-01, at 11. Specifically, MAC is concerned about the inclusion of costs of BPA's risk hedging activities associated with aluminum prices and natural gas prices. *Id.* MAC states that these activities do not benefit the Slice purchasers and therefore, the costs associated with these activities should not be included in the Slice Revenue Requirement. *Id.* MAC states that Slice purchasers assume this risk directly, so if BPA includes these costs, Slice purchasers essentially would be paying twice for mitigating this risk. *Id.*

BPA's Position

All hedging costs for risks assumed directly by the Slice purchaser are removed from the Slice Revenue Requirement. Mesa *et al.*, WP-02-E-BPA-54, at 13. However, hedging costs associated with the Inventory Solution will be included in the Slice Revenue Requirement, because these costs associated with the Inventory Solution are part of the Slice Revenue Requirement. *Id.*

There may be some costs associated with hedging activities that are not accounted for. BPA will not conduct a detailed accounting of staff salaries and related overhead costs in order to remove these costs associated with hedging activities from the Slice Revenue Requirement. *Id.*

Evaluation of Positions

SPG and MAC argue that BPA should remove all hedging costs from the Slice Revenue Requirement. SPG Brief, WP-02-B-SG-01, at 18; MAC Brief, WP-02-B-MA-01, at 11. BPA generally agrees with the idea that all hedging costs unrelated to the Slice product should be removed from the Slice Revenue Requirement. Mesa *et al.*, WP-02-E-BPA-54, at 13. BPA has attempted to do this, and the Slice Revenue Requirement reflects this effort.

However, the benefits of BPA's hedging activities do not flow only to non-Slice purchasers. Aspects of BPA's hedging activities provide benefits to both Slice purchasers and non-Slice customers. *Id.* Where the hedging activities provide a benefit to the Slice purchaser, the hedging costs will be included in the Slice Revenue Requirement or, if necessary, made part of the true-up. *Id.* An example of such cost would be hedging activities associated with the Inventory Solution. The Slice purchasers are responsible for the costs associated with the Inventory Solution. Mesa *et al.*, WP-02-E-BPA-32, at 13. In the event BPA incurs hedging costs or expenses associated with the Inventory Solution, it would be appropriate to include such costs in the Slice Revenue Requirement. Mesa *et al.*, WP-02-E-BPA-54, at 13.

The only possible exception to this general proposition is for the expenses associated with salaries and overhead for BPA's hedging activities. BPA stated in its rebuttal testimony that it will not perform a detailed accounting of staff salaries and related overhead costs to ensure that all non-Slice related costs are removed. *Id.* The segregation of these costs into Slice and non-Slice categories is not justified given limited benefit. *Id.* at 14. Even if such salary and overhead expenses were segregated, the amount would be insignificant and would have a negligible effect on the Slice Revenue Requirement. *Id.*

Decision

BPA eliminated hedging costs from the Slice Revenue Requirement, except for those hedging costs from which Slice purchasers receive some benefit.

16.4.4 IOU Residential Exchange Settlement Costs

Issue

Whether the Slice Revenue Requirement fully allocates to Slice purchasers the proportionate cost of the proposed settlement of the Residential Exchange with the IOUs.

Parties' Positions

SPG states that Slice purchasers will not be insulated from paying their share of the actual net costs of the settlement of the Residential Exchange with the IOUs. SPG Brief, WP-02-B-SG-01, at 17. This includes both the power and the financial benefits of the proposed settlement. SPG argues that, by virtue of BPA including the 1,000 aMW block sale to the IOUs in its loads and resources analysis, power is included in the Inventory Solution cost, which is included in the Slice Revenue Requirement. *Id.* at 13. In addition, Slice purchasers will be required to pay for a net cash equivalent of an additional 800 aMW, which has a projected cost of $54 million per year. *Id.* Slice purchasers will pay the proportionate share of the actual cost of this financial benefit, whatever the actual amount turns out to be. *Id.*

The DSIs contend that the Slice purchasers should pay their proportionate share of the settlement of the Residential Exchange with the IOUs. DSI Brief, WP-02-B-DS-01, at 84. The DSIs believe that SPG's proposal would limit the Slice purchasers' contribution to the power and financial benefits that BPA is offering to IOUs to settle the Residential Exchange. *Id.*

MAC disagrees with the DSIs' contention that the Slice Revenue Requirement includes only the 800 to 900 aMW of financial benefit of the proposed settlement of the Residential Exchange with the IOUs. MAC Brief, WP-02-B-MA-01, at 13. MAC states that the 1,000 aMW sold to the IOUs already is included in the load/resource balance used to calculate the net cost of the Inventory Solution, which the Slice Revenue Requirement includes. *Id.*

BPA's Position

BPA proposed that the Slice purchasers would be obligated for their proportionate share of the REP, including any settlement of the Exchange benefits with the IOUs. Mesa *et al.*, WP-02-E-BPA-54, at 9. This includes both the costs associated with the power deliveries and financial benefits to the IOUs under the proposed settlement. *Id.*

Evaluation of Positions

There appears to be some confusion among the parties regarding the obligation of the Slice purchasers for the cost of the REP and any settlement of the REP.

Slice purchasers will be responsible for paying their proportionate share of the costs of the REP or any settlement of the REP. The costs of the settlement of the REP include costs associated with both the power delivery and financial payment components of the proposed settlement. Mesa *et al.*, WP-02-E-BPA-54, at 9. Slice purchasers will not be insulated from the full cost of the proposed settlement of the REP, nor will they be insulated from the actual cost of the REP should some utilities choose not to accept the proposed settlement.

Decision

The Slice Revenue Requirement fully covers the full cost of the Residential Exchange, including any settlement of the benefits under that exchange.

16.4.5 Transmission Costs

Issue 1

Whether costs associated with transmission activities of the PBL should be removed from the Slice Revenue Requirement.

Parties' Positions

MAC states that BPA should remove costs associated with transmission activities of the PBL from the power scheduling costs allocated to the Slice product. MAC Brief, WP-02-B-MA-01, at 10.

BPA's Position

BPA has excluded all transmission costs (other than those associated with the transmission of System Obligations and GTAs) from the Slice Revenue Requirement. Mesa *et al.*, WP-02-E-BPA-54, at 13. BPA will not conduct detailed accounting of costs attributable to staff salaries and related overhead to remove "non-Slice" costs. *Id.* BPA believes that these amounts are insignificant and have a negligible effect on the Slice Revenue Requirement. *Id.* at 14.

Evaluation of Position

MAC's concern is that Slice purchasers will be paying for transmission management expense that should be excluded from the Slice Revenue Requirement. MAC Brief, WP-02-B-MA-01, at 10. MAC correctly notes that the Slice Revenue Requirement should not include costs associated with transmission management from power scheduling, except for those costs associated with the transmission of System Obligations and GTAs. *Id.* With the limited exception of the transmission expenses for System Obligations and GTAs, Slice purchasers directly assume the obligation for the transmission expense to market any surplus power. The only remaining aspect of transmission management costs that has not been separated for purposes of the Slice Revenue Requirement is salaries and overhead expenses. Mesa *et al.*, WP-02-E-BPA-54, at 13.

The BPA's transmission management group performs functions that would be considered both Slice and non-Slice related costs. Many of these activities would be difficult or impossible to precisely assign to the appropriate cost category.

For staff salary costs and related overhead costs associated with transmission management, BPA noted that it will not be conducting detailed accounting to remove such non-Slice costs from power scheduling costs allocated to the Slice product. *Id.* The amounts of staff salary costs and related overhead costs associated with managing non-Slice products, in general, are insignificant and have a negligible effect on the Slice Revenue Requirement. *Id.* at 14.

Decision

The costs associated with transmission activities of the PBL were removed from the Slice Revenue Requirement to the greatest extent possible, other than those associated with the transmission of System Obligations and GTAs.

Issue 2

Whether the stranded cost of PBL's transmission rights over the Southern Intertie should be included in the Slice Revenue Requirement.

Parties' Positions

The DSIs argue that the PBL is paying a significant amount of money to the TBL to purchase transmission rights over the Southern Intertie to market short-term firm power. DSI Brief, WP-02-B-DS-01, at 85; DSI Ex. Brief, WP-02-R-DS-01 at 30-31. The DSIs contend this transmission expense should be included in the Slice Revenue Requirement, because Slice sales diminish the short-term firm power available to BPA and thus diminish the amount of transmission rights needed by BPA. *Id.* The DSIs recommend that the Slice Revenue Requirement should include the annual cost of $8.1 million for excess intertie capacity already purchased by the PBL, plus any increase in "stranded" transmission rights created by Slice sales. *Id.*

MAC argues the transmission costs associated with PBL's pre-purchased Southern Intertie capacity should be excluded from the Slice Revenue Requirement. MAC Brief, WP-02-B-MA-01, at 14. MAC believes the DSIs overlook some important rights PBL has with respect to its obligations to the TBL related to the Southern Intertie that remove any possibility that there will be any stranded transmission costs for Southern Intertie capacity. *Id.* First, the MOA between TBL and PBL grants PBL termination rights prior to March 2017, pursuant to BPA's Open Access Transmission Tariff in effect at the time the termination is being noticed. *Id.* The current Open Access Transmission Tariff allows the PBL to terminate or reduce transmission demand upon two years' notice. *Id.* Second, should the PBL hold unneeded transmission rights on the intertie, the PBL should be able to remarket these unneeded rights, especially if they occur during the summer, when demand for intertie capacity is high. *Id.* Third, the MOA states that the notice periods for termination and conversion to another transmission service may be shortened upon mutual agreement of the parties. *Id.* at 15.

Therefore, the MAC concludes that there should not be any unused or surplus transmission rights for which costs would have to be included in the Slice Revenue Requirement. *Id.*

SPG states that there will not be any stranded transmission expenses related to the Southern Intertie as a result of the sale of Slice, because BPA can terminate or resell any excess capacity. SPG Brief, WP-02-B-SG-01, at 10-11.

BPA's Position

BPA did not include in the Slice Revenue Requirement the costs of pre-purchased transmission that BPA was intending to use for surplus sales outside the region. Tr. 1378. There are three reasons why BPA did not include these costs. First, BPA does not anticipate selling 100 percent of the generation output of Federal system resources as Slice products; therefore, some amount of pre-purchased transmission will be necessary for surplus sales outside the region. *Id*. Second, BPA has not pre-purchased transmission for all the surplus sales it anticipates making in the absence of Slice sales, so there is the potential that the amount of pre-purchased transmission may not be in excess of the amount of surplus sales BPA makes, once Slice sales are known. Tr. 1379. Third, BPA has termination rights with a two-year notice period, so that any excess transmission can be terminated, once Slice sales are known. *Id*. The gap in time between the commencement of Slice sales and the termination date for pre-purchased transmission could be approximately one year. *Id*. Any costs resulting from excess transmission held by BPA during this gap could be mitigated by remarketing to other customers, including Slice purchasers. *Id*.

Evaluation of Positions

The DSIs argue that $8.1 million of stranded Southern Intertie capacity should be added to the Slice Revenue Requirement. DSI Brief, WP-02-B-DS-01, at 85. The DSIs are concerned that responsibility for these stranded transmission costs will be borne solely by non-Slice purchasers. *Id.* The DSIs believe that if these costs are not included in the Slice Revenue Requirement, there will be a cost shift. *Id.*

The DSIs' contention that $8.1 million should be added to the Slice Revenue Requirement is highly speculative. DSI Brief, WP-02-B-DS-01, at 84-85. The DSIs do not explain how they determined that there would be $8.1 million in stranded transmission costs. *Id.* There is no evidence in the record that supports this conclusion. The Joint DSIs made a similar argument in their rebuttal testimony, but there they concluded that only $6.7 million should be included each year. Schoenbeck and Bliven, WP-02-E-DS/AL/VN-06, at 32. The DSIs provided no substantive analysis to support their conclusion that $6.7 million should be added to the Slice Revenue Requirement.

The DSIs' argument is premised on some assumed level of Slice sales. However, BPA did not forecast any Slice load as part of its initial proposal. Tr. 1341. Based on the zero Slice load forecast assumption, BPA is forecasting a need for all of the pre-purchased Southern Intertie transmission capacity to market surplus generation. Pedersen and McRae, WP-02-E-BPA-28, at 3. In fact, BPA may need to acquire additional transmission capacity to market its surplus, based on the assumption of no Slice load. Tr. 1378.

To create a stranded transmission expense, there must be a level of Slice sales high enough to displace BPA's need for the transmission capacity. The DSIs do not provide any explanation of what assumptions they are making about the presumed level of Slice sales. Without some understanding as to how the DSIs came to the conclusions they reach, it is impossible to evaluate, much less adopt, the proposal.

The DSIs' argument is further undermined by the fact that BPA has the ability to avoid most, if not all, of these stranded costs. Under PBL's agreement with the TBL, PBL can terminate a portion of the purchase upon two years' notice. Tr. 1378-79. Because the level of Slice sales will be known at least one year prior to the start of the Slice contract, BPA can terminate the agreement in whole or in part to limit its exposure. This one year of stranded costs will result only if BPA is unable to remarket the capacity or reach a mutual agreement with TBL to take it back on a shorter notice. *Id*.

MAC argues that BPA should have no costs associated with any excess transmission intertie capacity, because of BPA's termination rights through its MOA with the TBL. MAC Brief, WP-02-B-MA-01, at 14. Furthermore, any excess transmission intertie capacity can be remarketed, especially if it occurs during periods when demand for transmission intertie capacity is high. *Id.*

BPA agrees with MAC's argument, and BPA testified during cross-examination that BPA would not be encumbered with any stranded transmission costs as a consequence of selling Slice:

> Q. Will the amount of transmission that BPA would need for that purpose change if, for example, BPA were to sell 100 percent of the Federal system generation as a slice product?
>
> A. (Mr. Pearson) If we sold 100 percent, yes. But you have to look at the reason we did not--we chose not to include it. And there's three reasons for that: One, is in actuality we will not be selling 100 percent of the system with slice. We have not fully pre-purchased all the transmission we need, so there could be the potential that the amount of slice we sell will not interfere with the pre-purchase. Second, to the extent we do sell enough slice that it does displace some of that pre-purchased transmission, it has a two-year termination notice. We would know how much slice we sell by September 30, 2000. By October 1, 2001, the slice contracts would start. So there is--and we would terminate that what we do not need. There is only one year overlap there from October 1, 2001, to September 30, 2002. We would look at reselling that transmission so it would not result in a net cost and potentially reselling it to the slice customers, because there is still only a certain amount of transmission available in the Northwest.

Tr. 1378-79.

Decision

BPA will not adjust the Slice Revenue Requirement to include potential stranded costs due to excess Southern Intertie capacity.

16.4.6 Inventory Solution True-Up

Issue

Whether BPA should include the forecasted costs of the Inventory Solution in the Slice Revenue Requirement, rather than truing up to actual costs.

Parties' Positions

NRU testified that Slice purchasers will be shielded from costs associated with the Inventory Solution. Saven, WP-02-E-NI-04, at 12.

MAC argues that the actual costs of the Inventory Solution should be excluded from the true-up process for the Slice product. MAC Brief, WP-02-B-MA-01, at 12. MAC argues that the cost uncertainty associated with the Inventory Solution is due to BPA's discretionary decision to sell power to the DSIs, which is unrelated to the Slice product. *Id.* MAC believes that truing up to the actual costs of the Inventory Solution violates the basic premise of the product, because these are costs which result from decisions that go beyond BPA's statutory obligations. *Id.*

SPG also notes that, because BPA will true-up the Inventory Solution to actual MW after the Subscription contracts are signed, Slice purchasers will not, as NRU's testimony suggests, be shielded from the costs associated with an expanding Inventory Solution. SPG Brief, WP-02-B-SG-01, at 12. Any additional load placed on BPA after the close of Subscription will include a TAC that will place the costs of the additional augmentation on the actual purchaser and not all other customers. *Id.*

BPA's Position

BPA anticipates taking steps to supplement the capability of the FCRPS to meet the total load placed on BPA (Inventory Solution). Mesa *et al.*, WP-02-E-BPA-32, at 12. The Inventory Solution is defined as the power purchases needed to meet all load service requests made under the Subscription process on a planning basis. *Id.*

Slice purchasers will pay their proportionate share of all costs associated with increasing the current inventory in order to meet the total Subscription load. *Id.* at 13. The estimated net cost of the Inventory Solution will be included in the Slice Revenue Requirement. *Id.* The "net cost" of the Inventory Solution refers to the net amount of the costs associated with any inventory augmentation and the associated revenues from such inventory augmentation. *Id.*

The actual costs of the Inventory Solution will be excluded from the true-up process for the Slice product. Mesa *et al.*, WP-02-E-BPA-54, at 11. BPA will true-up to the actual MW of the

Inventory Solution 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 power rate case. *Id.*

The rationale for service to the DSIs is discussed in the testimony of Berwager *et al.,* WP-02-E-BPA-09, at 6-7. Both Slice and non-Slice customers will share the costs of extending the Inventory Solution. Mesa *et al.,* WP-02-E-BPA-54, at 10.

<u>Evaluation of Positions</u>

MAC argues that forecasted rather than actual costs of the Inventory Solution should be included in the Inventory Solution. MAC Brief, WP-02-B-MA-01, at 12. MAC does not specify whether the term "costs" refers to Inventory Solution MW or to the price ($/MWh) of the Inventory Solution, or both. There is some ambiguity, because MAC alludes to both the MW associated with BPA's decision to serve the DSIs and the volatility in the net cost of such service. *Id.* at 12-13.

BPA distinguishes between the MW component and the price component of its Inventory Solution costs. The MW component will be trued-up after the closing of the Subscription contract signing window, but the cost of the Inventory Solution ($/MWh) will not be subject to the true-up process. Mesa *et al.,* WP-02-E-BPA-54, at 11. By truing up to the actual MW of the Inventory Solution at the close of the Subscription contract signing window as opposed to using the forecasted MW amount of the Inventory Solution, all customer classes will share responsibility for the full amount of the Inventory Solution. Mesa *et al.,* WP-02-E-BPA-54, at 11-12. The equitable treatment between customer classes for this expense is assured by having both Slice and non-Slice customers assessed the same forecasted price for the replacement power. If BPA did not true-up to the actual MW of the Inventory Solution, there would be the possibility of a cost shift to or from Slice purchasers, if BPA did not accurately forecast the amount of Inventory Solution MW. Truing up to actual MW at the close of the Subscription signing window also assures that Slice purchasers will be not be shielded from an expansion of BPA's loads, as NRU's testimony suggested would be the case. Saven, WP-02-E-NI-04, at 12.

<u>Decision</u>

BPA will true-up the MW component of its Inventory Solution costs, but the price of the Inventory Solution ($/MWh) will not be subject to the true-up process.

16.5 <u>Cost Shifts</u>

<u>Issue 1</u>

Whether BPA should establish in this rate proceeding a limit on the amount of cost shift associated with Slice.

Parties' Positions

The DSIs are concerned that Slice sales may create unforeseen cost shifts. DSI Brief, WP-02-B-DS-01, at 85; DSI Ex. Brief, WP-02-R-DS-01, at 31. The DSIs believe that the greater the percentage of the generation output of the Federal system resources that is sold as Slice products, the greater the effect on non-Slice customers of any cost shift. *Id.* Given this uncertainty about the unforeseen cost shifts that could be caused by the sale of Slice, the DSIs recommend that BPA limit the volume of Slice products sold to 15 percent of the generation output of Federal system resources. *Id.* at 85-86.

NRU also is concerned about the magnitude of cost shifts due to Slice sales, particularly if the volume of Slice products sold exceeds 15 percent of the generation output of the Federal system resources. NRU Brief, WP-02-B-NI-02, at 27. NRU believes that the cost shifts associated with the sale of Slice will increase in terms of dollar amounts, proportionate to the increase in Slice sales beyond the 1,000 aMW range. *Id.* NRU believes that BPA should ensure that any cost shifts associated with the sale of Slice go no further than BPA's initial assumption of up to $7.7 million, assuming 15 percent of the generation output of Federal system resources is sold as Slice products. *Id.*

UCUT is concerned about increasing amounts of Slice purchases beyond the estimates of potential sales in BPA's initial proposal. UCUT Brief, WP-02-B-UC-01, at 23. UCUT recommends BPA consider all rate impacts that must be mitigated that result from the actual level of Slice sales differing from the level considered in BPA's initial rate proposal. *Id.* at 23-24.

SPG states that sales of the Slice product will not cause significant cost shifts to other BPA customers. SPG Brief, WP-02-B-SG-01, at 6. SPG states that BPA's cost shift study and SPG's own sensitivity study both demonstrate that there would be no measurable, significant cost shifts to other customers due to the sale of Slice. *Id.* at 6-7. SPG states that the DSIs mistakenly assume that the magnitude of cost shifts will increase as BPA sells greater amounts of the Slice product. *Id.* at 9. SPG believes the DSIs' argument is flawed. SPG states that the DSIs assume that the relationship between potential costs and amount of power assumed to be sold as Slice products in BPA's Cost Shift Study is perfectly linear and can be applied to higher amounts of power sold as Slice products, without critical examination. *Id.* SPG claims that BPA's Cost Shift Study may be unreliable in the upper ranges of assumed percent of the generation output of Federal system resources sold as Slice products. *Id.* at 10. If BPA's Cost Shift Study is unreliable in the upper ranges, then the DSIs' conclusion is entirely unsupported. *Id.*

SPG asserts that there are significant benefits to BPA, the Federal Government, and to other BPA customers from the sale of the Slice product. SPG Brief, WP-02-B-SG-01, at 4. Benefits include the shift of risks from BPA to the Slice purchasers, the improvement of BPA's ability to make its Treasury repayments, and the Slice purchasers' payment of their share of BPA's costs. *Id.* at 5.

MAC states that the sale of the Slice product will not result in improper shifting of costs to other power customers. MAC Brief, WP-02-B-MA-01, at 9. This is due to two main reasons:

(1) the Slice purchaser alone will face an annual rate true-up; and (2) Slice purchasers alone will bear responsibility for incremental resources necessary to serve their loads. *Id.* No other customers have to bear those risks. *Id.* MAC concurs with the conclusions of both BPA's Cost Shift Study and SPG's analysis, which show that the sale of Slice will not result in the shifting of costs from Slice purchasers to other BPA customers. *Id.*

MAC asserts that the sale of the Slice product creates benefits to BPA's non-Slice customers, because the sale of Slice significantly shifts FBS cost responsibility from the Treasury to Slice purchasers. MAC Brief, WP-02-B-MA-01, at 7. The Slice purchaser directly assumes the risks associated with weather, fish, and the energy marketplace, which strengthens BPA's ability to make payments to the Treasury and reduces the amount of any potential stranded costs. *Id.*

<u>BPA's Position</u>

The Slice product is a balanced product that has some provisions that are favorable to Slice customers, as well as some provisions that provide benefits to BPA's other customers. Mesa *et al.*, WP-02-E-BPA-54, at 2. The Slice product, in total, represents an equitable balance between risks and benefits for the Slice customers and non-Slice customers. *Id.*

BPA conducted a Cost Shift Study to examine the potential for cost shifts between the Slice product and other requirements products. Mesa *et al.*, WP-02-E-BPA-32, at 20. The results of this Cost Shift Study indicated that the 50 water year average annual cost shift to Slice purchasers of selling 15 percent of the generation output from the Federal system resources as Slice products is equal to $5.7 million. Wholesale Power Rate Development Study, WP-02-FS-BPA-05, Appendix C, Section 5.3. Given the sensitivity of the study, the margin of error in the assumptions, and the relatively small size of the cost shift results, BPA concluded that there would be no significant cost shift to or from Slice purchasers to or from other customers. Mesa *et al*., WP-02-E-BPA-32, at 22-23. Therefore, BPA believes that no further adjustments to the Slice rate are necessary, including developing a cost shift "cap." Mesa *et al.*, WP-02-E-BPA-54, at 7. BPA's Slice Cost Shift Study, while useful in determining whether or not there would be significant cost shifts caused by BPA selling 15 percent of the generation output from Federal system resources as Slice products, was not intended to be used to precisely calculate a cost shift amount that would set a "tolerable" upper limit. *Id.* at 7.

<u>Evaluation of Positions</u>

The DSIs, NRU, and UCUT are all concerned about the magnitude of cost shifts due to Slice sales, particularly if the volume of Slice products sold exceeds 15 percent of the generation output of the Federal system resources. DSI Brief, WP-02-B-DS-01, at 85; NRU Brief, WP-02-B-NI-02, at 27; UCUT Brief, WP-02-B-UC-01, at 23. To limit the potential cost shift associated with Slice sales to tolerable levels, the parties have slightly different recommendations. The DSIs recommend that BPA limit the volume of Slice products sold to 15 percent of the generation output of Federal system resources. DSI Brief, WP-02-B-DS-01, at 85-86. NRU recommends that BPA limit the cost shift associated with Slice sales to $7.7 million, assuming 15 percent of the generation output of Federal system resources is sold as Slice products. NRU Brief, WP-02-B-NI-02, at 27. UCUT contends that Slice should not be extended beyond the levels considered in the initial proposal. UCUT Brief, WP-02-B-UC-01, at 23.

BPA's initial proposal was silent about the need to limit or cap the amount of Slice available to its public preference customers. Since the initial proposal, however, several parties have recommended in their testimony that BPA limit in some fashion the amount of Slice offered. Saven, WP-02-E-NI-04, at 9-10; Schoenbeck and Bliven, WP-02-E-DS/AL/VN-06, at 36-38. In response to these and other concerns regarding Slice, BPA initiated a separate public process to examine whether it would be appropriate to cap or limit the amount of Slice available to public preference customers. Tr. 1344. As a result, BPA will not be considering setting limits on volume of Slice sales in this rate case. The Power Subscription Strategy Administrator's Supplemental ROD stated that Slice sales will be capped. Decisions with respect to the amount of such a volume limit will be made outside the rate case in a different forum.

The DSIs assert that without imposing some limit on the amount of Slice, there would be a cost shift to the non-Slice customers. DSI Brief, WP-02-B-DS-01, at 85. The DSIs' argument assumes that with the sale of Slice there would be some unspecified cost shift. The DSIs do not provide any quantitative analysis to support their assumption of a cost shift.

BPA conducted a Cost Shift Study to determine the "potential for cost shifts between the Slice product and other requirements products." Mesa *et al.*, WP-02-E-BPA-32, at 22. The Cost Shift Study found that, over the 50 water years, the cost shift to BPA from selling 15 percent of the system as Slice was $5.7 million. Wholesale Power Rate Development Study, WP-02-FS-BPA-05, Appendix C, Section 5.3. BPA concluded that "given the sensitivity of the study, margin of error in the assumptions, and relatively small size of the cost shift results," BPA did not believe offering Slice resulted in a significant cost shift. Mesa *et al.*, WP-02-E-BPA-32, at 22. BPA found that this cost shift of $5.7 million was equal to 2.1 percent of the Slice revenue. Wholesale Power Rate Development Study, WP-02-FS-BPA-05, Appendix C, Section 5.3. The Cost Shift Study confirmed that this percentage remained constant over the range of percentages of the Federal system generation sold as Slice.

NRU's argument asks that the Cost Shift Study be used to set the bounds for an acceptable cost shift. NRU Brief, WP-02-B-NI-02, at 26-27. NRU misinterprets the purpose of the Cost Shift Study and ignores one of the fundamental principles of the Slice product. BPA's Cost Shift Study was not intended to be used to precisely calculate a cost shift amount that would set a "tolerable" upper limit, as NRU suggests. Mesa *et al.*, WP-02-E-BPA-54, at 7. Rather, the Cost Shift Study is a tool to examine whether significant cost shifts would result from the decision to offer the Slice product. *Id.*

BPA has stated that one of its guiding principles in the decision to offer Slice was that it would not create a cost shift to or from those who chose to purchase Slice. Subscription ROD, at 85. It is BPA's overall objective that there would be no "tolerable" level of cost shifts that would be acceptable, as NRU's interpretation suggests. BPA recognizes, however, that absolute precision in the allocation of expenses between Slice and non-Slice purchasers in some instances may be difficult, and likely would have negligible effects. (*See* section 16.4.5 on allocation of transmission costs.) In these limited instances, however, the impact on rates, both Slice and non-Slice, is so negligible that there will be no material impact.

While SPG and MAC point out that there are significant benefits to BPA's non-Slice customers due to the costs and risks shifted to Slice purchasers, SPG Brief, WP-02-B-SG-01, at 4; MAC Brief, WP-02-B-MA-01, at 7; these benefits to non-Slice customers and BPA are balanced with benefits to Slice purchasers. Mesa *et al.*, WP-02-E-BPA-54, at 2.

Decision

BPA will not establish in this proceeding a limit on the amount of Slice cost shift.

Issue 2

Whether BPA offers comparability of future cost protection to Slice and non-Slice customers.

Parties' Positions

NRU argues that customers signing 10-year or longer Full Requirements contracts with BPA should receive the same protections Slice purchasers receive from the assignment of costs for future changes in the FBS (*e.g.*, fish and wildlife costs) or from the assignment of costs of load service obligations undertaken by BPA (*e.g.*, inclusion of DSI and IOU service in the Inventory Solution). NRU Brief, WP-02-B-NI-02, at 25.

BPA's Position

BPA believes that customers signing up for 10-year or longer Full Requirements contracts with BPA are treated no differently than Slice purchasers. Mesa *et al.*, WP-02-E-BPA-32, at 5.

Evaluation of Positions

NRU is concerned that BPA will provide Slice purchasers some extra protection from the assignment of costs, compared to costs assigned to non-Slice customers. NRU Brief, WP-02-B-NI-02, at 25. BPA does not believe this is the case in the FY 2002-2006 rate period, nor will this be the case in any future rate periods. Mesa *et al.*, WP-02-E-BPA-32, at 4. First, the Slice product, by design, includes the same costs for its revenue requirement as other products, with some limited exceptions. *Id.* at 5. Second, with respect to the assignment of costs of load service obligations undertaken by BPA (*e.g*., inclusion of DSI and IOU service in the Inventory Solution), the Slice purchasers are required to pay their proportionate share of these costs for the FY 2002-2006 rate period. *Id.* at 13.

After 2006, BPA will be determining the amount of the Inventory Solution in the then-applicable rate periods. *Id.* at 15. Both Slice purchasers and non-Slice customers will be responsible for paying their share of the Inventory Solution costs determined in the then-applicable rate periods. *Id.*

Decision

BPA is offering comparability of future cost protection to Slice purchasers and non-Slice customers.

16.6 Impact of Slice on Risk Mitigation

Issue 1

Whether BPA should adjust the CRAC thresholds downward based on the percentage of the generation from the Federal system sold as Slice.

Parties' Positions

SUB states that a methodology should be developed which adjusts the CRAC threshold to correspond to the actual amount of Slice load. SUB Brief, WP-02-B-SP-01, at 10. SUB contends that preference customers who do not purchase Slice will be burdened with unnecessarily high reserve requirements. *Id.* SUB asserts that an adjustment should be made to the CRAC threshold after September 30, 2000, when the level of Slice sales is known. *Id.*

WPAG similarly indicates that the failure to reflect Slice load in the risk analysis will increase the likelihood of the CRAC triggering for those customers that will not purchase power under the Slice Rate. WPAG Brief, WP-02-B-WA-01, at 15. WPAG argues CRAC is more likely to trigger because of the diminution in the accumulation of reserves when load is being placed under the Slice rate rather than the PF rate. *Id.* Because Slice purchasers are not contributing to PNRR, increases in reserve levels through PNRR and positive market conditions make it necessary to adjust the CRAC threshold downward so the Slice load will not increase the likelihood of a CRAC triggering. *Id.*

BPA's Position

While a percentage of Slice sales greater than zero would lower the contribution to reserve levels by PNRR (Slice rates do not have a PNRR component), the magnitude of risk that the reserves are designed to cover will also be smaller. Mesa *et al.*, WP-02-E-BPA-32, at 18-19. CRAC is a risk mitigation tool designed to be used as part of an overall risk mitigation package. Lovell *et al.*, WP-02-E-BPA-14, at 3. CRAC is a temporary upward adjustment to posted power prices if AANR fall below threshold levels set forth in BPA's initial proposal. *Id.* at 6, and Table A, Attachment 1. Although the CRAC thresholds are often discussed in terms of reserves (*e.g.*, WPAG Brief, WP-02-B-WA-01, at 15), BPA proposed that the thresholds be based on AANR, a similar measure. Lovell *et al.*, WP-02-E-BPA-14, at 6-7. Because Slice purchasers assume directly the financial risks CRAC is designed to mitigate, Slice purchasers will not be subject to an upward CRAC adjustment to the Slice rate. Mesa *et al.*, WP-02-E-BPA-32, at 16-17. By assuming the risks for which CRAC was designed to mitigate directly, the CRAC threshold is no more likely to be reached when BPA sells Slice.

Evaluation of Positions

WPAG and SUB both correctly note that there will be a direct relationship between the contribution to reserves through PNRR and the level of Slice sales. WPAG Brief, WP-02-B-WA-01, at 15; SUB Brief, WP-02-B-SP-01, at 10. However, WPAG and SUB focus on only one aspect of the impact of Slice load on BPA's risk profile and ignore a second, larger impact.

Slice sales have two major impacts on the relationship between the level of reserves and reaching the CRAC threshold. First, as noted by WPAG and SUB, the contribution to reserves based on PNRR is reduced by a percentage equal to the percent of the Federal system generation sold as Slice. Mesa *et al.*, WP-02-E-BPA-32, at 18-19. The higher the level of Slice sales BPA has, the lower the contribution to reserves will be from PNRR. *Id.* at 18-19. WPAG and SUB both argue that this will result in a greater likelihood of CRAC triggering due to a smaller number of customers contributing to the reserves through PNRR. WPAG Brief, WP-02-B-WA-01, at 15; SUB Brief, WP-02-B-SP-01, at 10.

While Slice sales do not contribute to reserves through PNRR, Slice creates a countervailing impact that provides a level of protection against reaching the CRAC threshold. Mesa *et al.*, WP-02-E-BPA-32, at 18-19. The Slice rate is based on BPA's actual costs, rather than the costs forecasted in the rate case. *Id.* at 9. As a consequence of Slice purchasers paying BPA's actual costs, the magnitude of risks that reserves will need to buffer will be smaller. *Id.* Through Slice, BPA is assured payment of its actual costs irrespective of generation levels, market prices, or expense levels. *Id*. at 2. The Cost Shift Study confirmed this. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 141. The Cost Shift Study found that both of these reductions would be proportional to the percentage of the system sold as Slice (the "linear relationship"). *Id.* For example, if 10 percent of the system is sold under Slice, the annual contributions to reserves based on PNRR would be reduced by 10 percent. *Id.*

By examining the reserve forecasts contained in the initial proposal, it is apparent that rather than increasing the likelihood of reaching the CRAC threshold, Slice will decrease the potential of it triggering. Lovell *et al.*, WP-02-E-BPA-14, at Attachment 2. The annual contribution to reserves based on PNRR in the initial proposal was $127 million. By contrast, the largest annual downswing in cash modeled in the ToolKit is approximately $1.13 billion. *Id.* Assuming 10 percent of the Federal generation is sold as Slice, the result would be a $12.7 million reduction in contribution to reserves from PNRR as compared to a $113 million reduction in maximum downward swing in cash BPA receives due to transfer of 10 percent of BPA's risk to Slice purchasers. A comparison of the two amounts allows one to conclude that Slice loads will reduce the likelihood of reaching the CRAC threshold for the non-Slice customer, not increase it as SUB and WPAG suggest. The same comparisons could be made for hypothetical Slice percentages of 20, 30, and 40 percent, and so on, supporting the same conclusion.

Decision

BPA will not adjust the CRAC threshold downward based on the percentage of the Federal system generation sold as Slice.

Issue 2

Whether BPA has adequately taken into account risks associated with meeting BPA's environmental obligations, assuming high levels of Slice sales.

Parties' Positions

UCUT states that a higher level of Slice sales poses risks that were not considered in the initial proposal. UCUT Brief, WP-02-B-UC-01, at 23. UCUT claims BPA should increase the PNRR to offset these additional risks. *Id.* at 23-24. UCUT contends that a higher level of Slice sales will lead to fewer revenues to support future environmental costs. *Id.* They believe this will result in additional economic and political pressures on BPA to cut its environmental programs. *Id.*

BPA's Position

BPA testified it will meet all of its statutory environmental obligations under the Northwest Power Act, NEPA, and ESA. DeWolf *et al.*, WP-02-E-BPA-39, at 33. BPA's rates and risk mitigation measures are designed to be sufficient to recover the costs of a wide range of future decisions on system reconfiguration and associated standards. *Id.* The revenue requirement, repayment schedule, and risk analysis took into account the full range of potential fish costs by identifying and modeling all significant risks. *Id.*

Through Slice, BPA is assured payment of its actual costs (which will include environmental costs) irrespective of generation levels, market prices, or expense levels. Mesa *et al.*, WP-02-E-BPA-32, at 18-19. To ensure that Slice did not shift costs, including those associated with BPA's environmental obligations, from Slice purchasers to non-Slice customers, BPA performed the Cost Shift Study. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 141. The Cost Shift Study confirmed there were no cost shifts that resulted from offering the product.

There is no evidence on the record to support UCUT's contention that Slice sales will have any impact on BPA's ability or motivation to meet its environmental obligations.

Evaluation of Positions

UCUT's concern is that the sale of Slice will increase the possibility that BPA will not meet its environmental obligations. UCUT Brief, WP-02-B-UC-01, at 23. UCUT provides no evidentiary support for this position.

UCUT's contention that the Slice sales will lead to fewer revenues to support future environmental costs is based primarily upon an assumption that Slice sales will somehow result in smaller revenues, lessening BPA's ability to meet its environmental obligations. *Id.* UCUT does not provide any analysis to support this contention, nor does it explain what features of the product design will cause this to happen.

BPA testified that it intends to fully comply with all of its environmental obligations. DeWolf *et al*., WP-02-E-BPA-39, at 33. This includes obligations under the Northwest Power Act, ESA, and NEPA. *Id*. Rates (including that for Slice) were designed and the risk mitigation package was created to ensure that BPA will meet the broad range of potential environmental obligations it could face in the future. *Id.*

To confirm that Slice would not result in customers avoiding environmental or other obligations, BPA conducted the Cost Shift Study. Mesa *et al*., WP-02-E-BPA-32, at 20. The Cost Shift Study found that there was a linear relationship between the percentage of the Federal system generation sold as Slice and the payment of an equal percentage of the Slice Revenue Requirement. Mesa *et al.*, WP-02-E-BPA-32, at 18. Therefore, over the term of the Slice contract, selling part of the Federal system generation as Slice products is net revenue-neutral to BPA and its customers, and therefore, there are no resulting cost shifts to or from Slice purchasers, and no further adjustments to the Slice rate are necessary. *Id.* at 23. Based upon the conclusion of the Cost Shift Study, there should be no negative financial consequence from Slice sales that would result in BPA failing to meet its financial obligations.

In addition, Slice was designed, in part, to relieve BPA of a degree of risk and share that risk with the Slice purchasers. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 41-43; Tr. 1371; Mesa *et al*., WP-02-E-BPA–32, at 17. As explained in the Subscription ROD, "Purchasers of Slice would pay a pre-established portion of BPA's revenue requirement regardless of weather, streamflow, market, or generation output conditions. This assured payment would tend to mitigate BPA's financial risks in the event that any of these conditions put adverse financial pressure on BPA." Subscription ROD, at 83. The annual true-up mechanism would ensure that Slice purchasers pay the actual costs incurred by BPA. Mesa *et al*., WP-02-E-BPA-32, at 9-12. As the Subscription ROD noted, "This feature would help stabilize BPA's financial picture by sharing unexpected costs, as well as savings, with the Slice purchaser." Subscription ROD, at 83.

Decision

BPA has adequately taken into account risks associated with meeting BPA's environmental obligations even if there are high levels of Slice sales.

Issue 3

Whether BPA should revise its proposal to account for the risk-mitigating effects of expected Slice sales and adjust the TPP downward.

Parties' Positions

The DSIs note that BPA's risk mitigation package is based on a forecast of no Slice sales. DSI Brief, WP-02-B-DS-01, at 52-53. Because BPA anticipates some sales of Slice, these actual Slice sales will reduce some of BPA's risk and increase the TPP. *Id.* BPA should revise the risk mitigation package to reflect the anticipated Slice sales. *Id.*

Alcoa/Vanalco argue that BPA is attempting to overcollect from its customers for risks that it does not face. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 53.

In Alcoa/Vanalco's brief on exceptions, they contend that the Risk Analysis Panel was incorrect in stating that BPA expected to make no Slice sales, because the evidence suggests that there is significant interest in the product. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 29. They also believe that BPA failed to analyze the effects of the anticipated Slice sales on BPA's risk position. *Id.* Alcoa/Vanalco state that BPA did not properly incorporate Slice sales into its risk analysis, because BPA only considered the increased risks Slice presented BPA and not reductions in risk. *Id.* at 29-30. As a consequence of these actions, Alcoa/Vanalco believe that BPA is double collecting for the same risk. *Id.* at 31. Alcoa/Vanalco believe that there should be a reduction in PNRR as the sales of Slice increase. *Id.* at 33. Alcoa/Vanalco also contend that there is no evidentiary support for BPA's claim that there is a corresponding decrease in PNRR as Slice sales increase. *Id.*

BPA's Position

BPA performed a risk analysis and designed a risk mitigation package for this rate case that assumed there would be no Slice sales. Tr. 1938. Using the forecast of no Slice load, the risk mitigation package in the initial proposal would assure that BPA achieved an 88 percent TPP. *Id.* BPA has developed the risk mitigation package in this fashion for two reasons. First, Slice is designed so that if there are Slice sales, the costs and risks to other parties, specifically including non-Slice customers and the Treasury, will not increase. Mesa *et al*., WP-02-E-BPA-32, at 16-23. Similarly, no Slice sales were assumed in developing the risk package, so that in the event Slice sales are smaller than what BPA may have attempted to forecast, BPA's risk profile would not be adversely impacted. Tr. 1939.

Evaluation of Positions

The DSIs and Alcoa/Vanalco both argue that BPA's risk mitigation experts took it as their charge to assure BPA of having an 88 percent TPP. DSI Brief, WP-02-B-DS-01, at 52; Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 33. Because BPA's risk mitigation package is based on no Slice sales, the DSIs contend TPP is actually greater than 88 percent, because some Slice sales are anticipated. DSI Brief, WP-02-B-DS-01, at 53. The DSIs argue that BPA does not dispute that there could be as much as 4,000 MW of Slice load, yet the DSIs fail to provide any substantive evidence as to the anticipated amount of Slice load. *Id.* The DSIs also do not provide any substantive analysis showing how much TPP would increase due to their undefined level of Slice sales.

Alcoa/Vanalco contend that BPA did not properly incorporate Slice sales into its risk analysis. Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 29. Alcoa/Vanalco claim that because BPA failed to properly incorporate Slice sales into its risk analysis, BPA is double collecting PNRR. *Id.*

Despite the lack of substantive evidence to support the conclusion, the DSIs state that PNRR should be reduced to account for the increased TPP due to Slice sales. DSI Brief, WP-02-B-DS-01, at 52-53. Alcoa/Vanalco similarly argue that BPA is attempting to overcollect PNRR for risk it does not face. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 53; Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 33.

BPA believes that Slice load would not cause an overcollection of PNRR or significantly affect TPP. Tr. 1361. In the event there are actual Slice loads, as those actual loads increase, the amount of PNRR collected decreases. Mesa *et al*., WP-02-E-BPA-32, at 17. The amount of PNRR collected decreases in a linear relationship to the amount of Slice that is purchased. *Id.* at 18-19. For example, if 15 percent of load were to be sold as Slice, then BPA would collect 15 percent less PNRR. Slice purchasers accept the risk of market variability, hydro variability, and other risks directly rather than using PNRR and CRAC to mitigate risks. *Id*. at 18-19.

If BPA were to project some percentage of Slice sales in its rate case forecast, BPA would have to add a corresponding level of PNRR to account for the volatility surrounding the assumption. Tr. 1360-62. This additional risk variable would likely counteract any projected decrease in PNRR and TPP. Tr. 1361.

It is appropriate to base BPA's risk mitigation package on a forecast of zero percent Slice load. Tr. at 1938, 1939. "By basing our risk analysis on an assumed level of no Slice sales, we were able to assemble a risk mitigation package that met the financial goal of 88 percent Treasury payment probability that would still be achieved almost certainly, not absolutely certainly, if there were Slice sales. It did this without shifting risk to the non-Slice customers." Tr. 1938-1939.

It would be imprudent to base BPA's risk analysis on an expected level of Slice sales, because the actual level of Slice sales is unknown. While there has been some preliminary interest in Slice, BPA testified that this interest could not be interpreted as a precise indication of the level of sales that will result. Tr. 1341-48. Furthermore, BPA testified that because of the unique nature of Slice, many of the parties participating in the dry runs were evaluating the product in light of their own power needs. *Id*. Given how different Slice is from BPA's traditional PF products, it would be impossible to anticipate with any degree of certainty the precise levels of Slice sales. *Id*. If BPA did assume a particular level of Slice load and reduced the PNRR in its rates, if the actual Slice loads turned out to be lower than the level assumed, BPA would find itself immediately in the position of having a TPP below its rate case goal.

While there is a potential for some levels of Slice sales, and while it is possible that actual Slice sales may increase the TPP, this does not require BPA to modify the risk mitigation package or risk analysis. Non-Slice customers are not harmed by this approach. If no Slice sales were anticipated, BPA would calculate PNRR in the manner it has in this rate case and in past rate cases. If it turns out that there are Slice sales, non-Slice customers will be no worse off than if there were no Slice sales.

Decision

BPA will not change the risk mitigation package based on the expectation of some level of Slice sales.

16.7 Irrigation Mitigation

Issue

Whether combining Slice with an irrigation mitigation product is an issue within the scope of the 2002 power rate case.

Parties' Positions

WPAG testified that Slice purchasers should not be eligible to purchase the surplus irrigation mitigation product. Cross *et al.,* WP-02-E-WA-01, at 48. WPAG states that under Slice, the purchaser is entitled to both requirements and surplus power generated by the system. *Id.* WPAG claims that no further irrigation mitigation is necessary, because the Slice purchaser will already be receiving its share of surplus power through the Slice purchase. *Id.*

NRU contends that WPAG's assertion that no further irrigation mitigation is necessary is factually incorrect. NRU Brief, WP-02-B-NI-02, at 23. NRU states that because most of the irrigation utilities have summer peaks, Slice may meet the utilities' load during May and June, but will likely not meet its needs in July and August, when the surplus component of Slice is generally smaller. Saven, WP-02-E-NI-05, at 31-32. NRU suggests that Slice purchasers should be entitled to a block purchase heavily shaped during the late summer when irrigation loads are the greatest. *Id.* at 32. NRU noted, however, that this is not an issue in the 2002 power rate case. *Id.* at 33.

BPA's Position

The determination of whether a Slice purchase can combine Slice with an irrigation mitigation product is not an issue in the 2002 power rate case.

Evaluation of Positions

The debate between WPAG and NRU over whether a Slice purchaser is entitled to some type of irrigation mitigation product is not an issue in this rate case. There are a number of issues surrounding the decision to offer Slice that will be resolved outside of this proceeding. These issues include at what level the amount of Slice offered should be capped (the decision whether to cap Slice sales already having been made outside the power rate case in the Power Subscription Strategy Administrator's Supplemental ROD), as well as eligibility for an irrigation mitigation product.

Decision

Any decision regarding combining Slice with an irrigation mitigation product will be made outside of the 2002 power rate case.

16.8 Slice Methodology

16.8.1 Introduction

The idea of submitting a Slice Methodology to FERC for approval was first raised by SPG in its direct case. Carr *et al.*, WP-02-E-SG-01, at 11. BPA, in rebuttal, agreed in general with the idea of submitting a Slice Methodology to FERC for approval for 10 years, but differed with SPG on some of the elements contained in SPG's proposed Methodology. Mesa *et al.*, WP-02-E-BPA-54, at 10.

In concept, the proposed Slice Methodology would provide the basis for calculating the Slice rate and annual true-up in the current rate period and also in future rate periods. Carr *et al.*, WP-02-E-SG-01, at 11. The methodology was to provide a consistent method of calculating the rate without determining what the rate will be in the future. *Id*.

16.8.2 Approval of Slice Methodology

Issue

Whether BPA should seek 10-year approval of the Slice Methodology.

Parties' Positions

The DSIs argue that BPA should not seek 10-year approval of the Slice Methodology because of the uncertainty surrounding the Slice product. DSI Brief, WP-02-B-DS-01, at 85-86; DSI Ex. Brief, WP-02-R-DS-01, at 31. The DSIs reason that because Slice is a new and untested product, BPA cannot be assured that it will actually recover all of its costs as planned. *Id.* at 85. The DSIs state that because of the absence of any experience with the product, BPA should not seek FERC approval of the methodology for more than five years so that BPA can make any necessary adjustments to ensure total cost recovery. *Id.* at 86.

MAC states that BPA should seek approval of the Slice Methodology for a minimum of 10 years. MAC Brief, WP-02-B-MA-01, at 5-7. MAC contends that seeking long-term approval of the Slice Methodology is the "only real protection against the vagaries of BPA's programmatic spending decisions." *Id.* at 5. Without long-term approval of the Slice Methodology, MAC contends, the "Slice contract would become the customer's blank check that BPA could endorse over to any cause or interest group. . . ." *Id.* at 5-6. MAC believes that "FERC approval ensures the balance of risks between the Slice product and other products will be maintained over the long term." *Id.* at 7.

SPG also states that BPA should seek 10-year approval to ensure the proper balance of risks between Slice and BPA's other power products. SPG Brief, WP-02-B-SG-01, at 15-16. SPG believes that seeking 10-year approval is consistent with section 7(a)(1) of the Northwest Power Act and does not conflict with the Administrator's ratesetting directives. *Id.* at 16.

In the IOU brief on exceptions, the IOUs contend that BPA should not offer the Slice contract for a period of 10 years. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 49. The IOUs believe that it is poor public policy to offer a Slice contract for 10 years because the product is new and untested and there is no assurance that BPA will recover its costs. *Id.* at 49-50.

SPG states in its brief on exceptions that BPA adopted the new cost test in the Slice methodology that will drastically change the Slice rate. SPG Ex. Brief, WP-02-R-SG-01, at 5. The SPG contends that BPA's proposal, which provides for adding new generation costs or credits to the Slice Revenue Requirement that result from fulfilling System Obligations or other generation function costs, makes the methodology meaningless and is a fundamental change from BPA's initial proposal. *Id.* According to the SPG, BPA's proposal was that the costs and credits would be included "if and only if they are directly attributed to the costs of the Slice generating resources (Slice System)." *Id.* at 3-4. The SPG believe the change to the Slice methodology is not supported by any evidence in the record and is arbitrary and capricious. *Id.* at 6.

<u>BPA's Position</u>

BPA believes it is appropriate to offer Slice contracts for a period of 10 years and to seek approval of the Slice Methodology from FERC for a period of 10 years as well. Mesa *et al.*, WP-02-E-BPA-54, at 10.

BPA also believes that the addition of new generation costs or credits to the Slice Revenue Requirement should include those that result from fulfilling System Obligations or other generation costs. Whether this test for adding new cost or credit items to the Slice Revenue Requirement will result in a drastically different Slice rate is highly speculative. Any change (increasing or decreasing) to the Slice rate will depend entirely upon whether there are cost or credit items that should appropriately be assessed to the Slice Revenue Requirement.

<u>Evaluation of Positions</u>

The Slice contract will be for a minimum of 10 years (2002-2011). Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 154. As such, Slice purchasers will be locked into a contractual obligation through the FY 2007-2011 rate period. Because rates for those five years will not be set until some time in the future, there is uncertainty surrounding what the Slice rate will be in that second rate period. SPG proposed in its direct testimony that BPA seek FERC approval for the methodology used to develop the Slice rate for a 10-year period. Carr *et al.*, WP-02-E-SG-01, at 11. SPG points out that the primary purpose for seeking 10-year approval of the Slice Methodology would be to provide the Slice purchaser with some level of assurance that the Slice Revenue Requirement will consist of the same basic components and that the annual true-up will be conducted in a consistent fashion for the duration of the contract. *Id*.
FERC approval of the Slice Methodology would not constitute a mechanism for locking in the proposed rate for the term of the contract and thereby would avoid the possibility of contributing to the payment of higher costs BPA may face in the next rate period. *Id.* Rather, the Slice Methodology is the establishment of a set of cost categories and rate design features that would be employed for the duration of the contract. *Id*. at 11-12.

By seeking 10-year approval of the Slice Methodology, the balance of risks between Slice purchasers and non-Slice purchasers is ensured. Mesa *et al.*, WP-02-E-BPA-54, at 10. While BPA agrees with the concept of 10-year approval of the Slice Methodology, BPA does not agree with all of the elements contained in the proposed Slice Methodology attached to the SPG's direct testimony. Approval for 10 years also ensures that Slice purchasers have rate protections similar to ones BPA has given other customers signing contracts for a duration beyond the current rate period.

In their brief on exceptions, the IOUs raise for the first time BPA's decision to offer Slice contracts for a 10-year period. The IOU argument is barred for two reasons. First, the decision to offer Slice contracts for a period of 10 years is not a rate case issue. The decision to allow a Slice contract for a minimum of 10 years was made in the Subscription ROD. Subscription ROD, at 96.

Even if the issue is not outside the scope of this proceeding, the IOUs are nonetheless barred from advancing it for the first time in their brief on exceptions. Pursuant to §1010.13(b) of BPA's *Rules of Procedure Governing Rate Hearings*, "Parties whose briefs do not raise and fully develop their position on any issue shall be deemed to take no position on such issue. Arguments not raised are deemed to be waived." Having not raised this argument in its initial brief, the IOUs have waived the matter. *See* ROD section 1.1.3.

SPG contends that there is not sufficient evidence in the record to support changing the Slice Methodology to require the addition of new generation costs or credits to the Slice Revenue Requirement resulting from fulfilling System Obligations or other generation cost. SPG Ex. Brief, WP-02-R-SG-01, at 5. The SPG believes that this provision in the Slice Methodology is a fundamental change to BPA's initial proposal that incorporated the Slice product description.

The SPG's argument is based upon the notion that adding of new costs or credits to the Slice Revenue Requirement is a fundamental change from the initial proposal. Contrary to the SPG argument, however, BPA's initial proposal did not include a Slice Methodology. SPG Ex. Brief, WP-02-R-SG-01, at 5. The concept of the Slice Methodology was first proposed by the SPG in its direct case. WP-02-E-SG-01, at Attachment 5. BPA also did not discuss the "new cost test" or incorporate the Slice Product description as part of its initial proposal as stated by the SPG. SPG Ex. Brief, WP-02-R-SG-01, at 5.

The Slice Methodology was designed to ensure that new costs that are appropriately assigned to Slice purchasers are incorporated into the Slice Revenue Requirement. PBL costs or credits not otherwise specifically dealt with in the Slice Revenue Requirement may be included in both the Slice Revenue Requirement and the Actual Slice Revenue Requirement (True-Up) if and to the extent that:

Such PBL costs or credits could be properly includable in PBL's wholesale power rates; and either:

- Such PBL costs or credits are: (1) incurred by PBL to provide service to customers other than Slice purchasers; and (2) incurred to provide service to or otherwise benefit Slice purchasers;

OR

- Such PBL costs or credits are not incurred to provide service to customers other than Slice purchasers, nor to provide service to or otherwise benefit Slice purchasers.

By designing the Slice Methodology in this fashion, BPA will be assured that there will not be any cost shifts between Slice and non-Slice customers.

Decision

BPA will seek approval of the Slice Methodology for a minimum of 10 years.

Issue

Whether there is sufficient evidence on the record to support the inclusion of System Augmentation and Conservation Augmentation in the Slice Revenue Requirement.

Parties' Positions

The SPG raises for the first time in its brief on exceptions the belief that BPA has improperly revised the amount of System Augmentation from the 1,112 aMW in the Slice Revenue Requirement contained in the initial proposal to 1,282 aMW in the Draft ROD. SPG Ex. Brief, WP-02-R-SG-01, at 7. In addition, the SPG contends that BPA has also improperly added Conservation Augmentation to the Slice Revenue Requirement. *Id.* at 8. The SPG argues that there is no evidence in the record to support either of these changes. *Id.*

BPA's Position

There is substantial evidence on the record to support and explain the addition of Conservation Augmentation. Tr. at 877. There is also substantial evidence to support the update of the System Augmentation numbers. Tr. at 839 and 841-43.

SPG's attempt to raise these issues in its brief on exceptions is barred. Under BPA's *Rules of Procedure Governing Rate Hearings*, parties are prohibiting from raising new issues in their briefs on exceptions. *See Procedures*, §1010.13.

Evaluation of Positions

The Slice Revenue Requirement is designed to include the same cost items as other products, with the exception of power purchases, inter-business line transmission costs and PNRR. Mesa *et al.*, WP-02-E-BPA-32, at 5. One aspect of the Slice Revenue Requirement for which Slice purchasers are responsible is the net cost of the Inventory Solution. *Id.* at 12-13. The net cost of the Inventory Solution in the initial proposal included the costs associated with purchasing 1,112 aMW. *Id*. (This amount should have been the 1,116 aMW reflected in the Loads and Resources Study)

During cross examination, BPA witnesses explained that there would be two changes to the Loads and Resources Study that would impact the augmentation purchases from which the net cost of the Inventory Solution is calculated. The first adjustment was that there would be a change to the load forecast due to Conservation Augmentation. Tr. 839 and 877. This adjustment reduced the public agency loads by 20 aMW per year for each of the five years of the rate period. Tr. 877. This results in an average 60 aMW annual reduction over the five years of the rate period. *Id.*

The second adjustment to the Loads and Resources Study was an update to current hydroregulations. Tr. 839. BPA updated the Study to incorporate the 99/2000 PNCA data submittals. Tr. 842. As a consequence of updating to the more recent PNCA submittals, there are 144 fewer megawatts generated by the hydro system during critical water. Tr. 841.

The reduction in these generation levels leads to a need to forecast additional augmentation purchases. Tr. 843. The combination of the Conservation Augmentation and the reduction in hydro generation levels resulted in a need to increase augmentation purchases from the 1,116 aMW forecasted in the initial proposal to the current forecast of 1,282 aMW. It should be noted, however, that the net cost of the Inventory Solution for system augmentation will be adjusted to reflect actual megawatts and not the amount forecasted in this rate case. Mesa *et al.*, WP-02-E-BPA-54, at 11. BPA testified that it will true-up System Augmentation, after the Subscription contract signing window closes, to the amount of actual megawatts necessary, based on the level of sales. *Id.* Therefore, for purposes of the Slice Revenue Requirement and the precise calculation of the Slice rate, the current forecast of 1,282 aMW of System Augmentation purchases may increase or decrease, depending on the actual level of power sales that result from the Subscription process.

Even if the SPG could legitimately contend that this issue is not supported in the record, the SPG is nonetheless barred from advancing it for the first time in its brief on exceptions. Pursuant to §1010.13 (b) of BPA's *Rules of Procedure Governing Rate Hearings*, "Parties whose briefs do not raise and fully develop their position on any issue shall be deemed to take no position on such issue. Arguments not raised are deemed to be waived." Having not raised this argument in its initial brief, the SPG has waived the matter.

Decision

There is substantial evidence in the record to support the inclusion of System Augmentation and Conservation Augmentation in the Slice Revenue Requirement.

17.0 WHOLESALE POWER RATE SCHEDULES

17.1 Introduction

In the 2002 rate case, BPA proposed major changes in the design of its wholesale power rates. *See* Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 1-3. Most of these changes are covered elsewhere in the ROD; this chapter reflects primarily changes to the rate schedules. BPA's 2002 rate schedules have been revised in format and content to reflect BPA's Subscription Strategy and the goals stated therein. Burns and Elizalde, WP-02-E-BPA-08, at 7.

BPA proposed greater flexibility in power products and power product pricing by:

- offering optional stepped rates for the five-year rate period, and a five-year average rate;
- offering energy and demand charges with 12 monthly seasons per year;
- using market forecasts to develop the monthly Demand Charge to send more accurate price signals;
- measuring monthly peak for purchasers of the Full Service Product on the customer's monthly peak coincident with BPA's monthly system peak, and for purchasers of the Actual Partial Product on their system peak; and
- replacing the Load Shaping Charge with a Load Variance Charge.

Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 6-7; Burns and Elizalde, WP-02-E-BPA-08, at 5-6. Also new for this rate period is the TAC, which will recover the costs of market purchases needed to serve customers requesting additional service after the close of the Subscription window. *Id*. at 6. *See also* Arrington *et al*., WP-02-E-BPA-24, and ROD section 10.15. An IPTAC has been designed to allow power to be sold to the DSIs at a price that reflects a melding of power sold from the FBS and power purchased specifically to serve the DSIs. Berwager *et al*., WP-02-E-BPA-09, at 8-9; *see* ROD section 15.5.

BPA is establishing the Residential Load Firm Power (RL-02) rate. This rate applies to net requirements sales under section 5(b) of the Northwest Power Act to IOUs that participate in a settlement of the REP, as described in BPA's Subscription Strategy. Leathley *et al*., WP-02-E-BPA-19, at 8-14; *see also* ROD sections 2.1 and 12.3. The PF Exchange Subscription rate was developed for in-lieu power sales under section 5(c) of the Northwest Power Act, in a settlement of the REP as described in BPA's Subscription Strategy. Leathley *et al*., WP-02-E-BPA-19, at 14-15.

The Load Variance Charge will recover the costs of the variability in monthly energy consumption within a BPA customer's system. The Load Variance Charge under the Full and Actual Partial Service products enables customers' billing factors to follow actual consumption.

This differs from Block products, where the amounts to be paid are fixed in advance. Keep *et al*., WP-02-E-BPA-17, at 7; *see* ROD section 10.5. The SUMY Block Charge is applicable to Block purchases if the annual amounts that are specified in the contractual commitment increase (*i.e*., step-up) over multiple years of a purchase commitment term due to projected increases in customer net requirements that are not subject to a TAC. Keep *et al*., WP-02-E-BPA-17, at 10; *see* ROD section 10.9. BPA has changed its method of computing UAI Charges so they more effectively encourage customers to buy the products they need and avoid exceeding their contractual entitlement to take power. Keep *et al*., WP-02-E-BPA-17, at 14-15; *see* ROD section 10.6. Similarly, the Excess Factoring Charge provides a penalty to the customer that requires BPA to provide factoring service (energy distributed among hours to match a load shape) that is outside the factoring benchmarks. Keep *et al*., WP-02-E-BPA-17, at 19-20; *see* ROD section 10.7.

BPA is offering a Slice product, a power sale based upon a Slice participant's annual net firm requirements load, shaped to BPA's generation from the Federal system resources. Mesa *et al*., WP-02-E-BPA-32, at 2. The Slice product, rate, and methodology are described in detail in ROD chapter 16 and Attachment 1. The Slice rate will apply uniformly over the five year rate period. The Slice true-up adjustment charge, positive or negative, will recover the difference between the forecasted Slice Revenue Requirement and actual expenses and credits of the Slice Revenue Requirement. *See* ROD chapter 16.

The C&R Discount will help sustain and encourage conservation and renewable resource development and low-income weatherization. The GEP is a dollar amount that customers will pay in addition to the applicable rate to purchase EPP. Esvelt *et al*., WP-02-E-BPA-33; *see* ROD sections 10.13 and 10.14.

Cost-based indexed rates for PF and IP are designed to recover revenues over the term of the indexed rate approximately equivalent to the applicable fixed rate. The indexed rate for DSI smelters would offer DSIs with aluminum smelter operations a tool that should promote smelter survivability during periods of low aluminum prices, while providing BPA with revenues necessary to recover its costs. Miller *et al*., WP-02-E-BPA-21, at 2; *see* ROD section 10.16.2. Indexed rates for non-smelter DSIs will be available, at BPA's discretion, if BPA and the DSI can mutually agree to an appropriate industry or commodity index. Miller *et al*., WP-02-E-BPA-21, at 6; *see* ROD section 10.16.2. The cost-based indexed PF rate allows BPA to offer utility customers pricing flexibility related to power market prices. Miller *et al.*, WP-02-E-BPA-21, at 16-17; *see* ROD section 10.16.1. Flexible PF, IP, and NR rates will continue to be available, at BPA's discretion. Gustafson *et al*., WP-02-E-BPA-23, at 7-9; *see* ROD section 10.10.

BPA continues to offer the LDD. Issues related to the LDD are addressed in ROD section 10.12.

As noted in the Wholesale Power Rate Schedules, contract language prevails over the rate schedule language and GRSPs.

17.2 Major Rate Design Proposals Affecting More Than One Rate Schedule

17.2.1 Definition of Dow Jones Mid-Columbia Index

Issue 1

How to define and reference the DJ Mid-C Indexes in the GRSPs.

Parties' Positions

PGP notes its concerns about the definitions pertaining to the DJ Mid-C Indexes as they appear in the GRSPs. PGP proposes an alternative definition, and also proposes to eliminate the definition for the Mid-C Bus. Knitter *et al*., WP-02-E-PG-01, at 7; PGP Brief, WP-02-B-PG-01, at 8-9.

BPA's Position

In the GRSPs for the initial proposal, BPA defined the DJ Mid-C Indexes as the price indexes for "the sale of firm and nonfirm power traded at the Mid-Columbia Bus." Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 117. BPA also included a definition for the Mid-C Bus. *Id.* at 120. In rebuttal testimony, BPA agreed that the first sentence of PGP's proposed definition for the DJ Mid-C Indexes constitutes an appropriate modification, and indicated BPA's intent to adopt that portion of PGP's suggested language for the final GRSPs. Keep *et al*., WP-02-E-BPA-43, at 32. BPA does not agree, however, to adopt the remainder of PGP's proposed definition, which addresses establishment of successor price indexes. *Id*. *See, infra,* Issue 2.

Evaluation of Positions

PGP's suggestion not to include the definition of the Mid-C Bus in the GRSPs is reasonable and appropriate. BPA will not include the definition for the Mid-C Bus in the final GRSPs in the Wholesale Power Rate Schedules. PGP witnesses claim the definition has three problems. First, they want to ensure that BPA uses publicly available, published indices published by a third party, *e.g.*, Dow Jones. This would prevent the possibility that BPA will unilaterally reinterpret the definition in the event that the nature of the Dow Jones index changes in the future, and avoid the risk of BPA creating a reporting burden on Mid-C utilities in the event that Dow Jones discontinues the index or BPA determines that the Dow Jones indices no longer serve the intent of the rate schedule. Knitter and Peters, WP-02-E-PG-01, at 7. PGP recommended the following language to define "Dow Jones Mid-C Indexes (DJ Mid-C Indexes)":

> Average HLH and average LLH price indices for sales of electricity at delivery points along the mid-Columbia River, as published by Dow Jones & Company, Inc. In the event that the DJ Mid-C Indexes cease to be published, other independently compiled and published electricity price information shall be used, as agreed by the Customer and BPA.

Id. BPA agrees that the definition for the Mid-C Bus can be eliminated.

PGP's proposed modification to the definition of the DJ Mid-C indexes in the GRSPs is appropriate with the addition of clarifying language to ensure that the definitions for peak and offpeak periods at the DJ Mid-C index are aligned with BPA's defined HLH and LLH periods.

Decision

At PGP's suggestion, BPA has replaced the definition for the DJ Mid-C Indexes with the following language: "Average heavy load hour (or peak) and average light load hour (or offpeak) price indices for sales of electricity at delivery points along the mid-Columbia River, as published by Dow-Jones & Company, Inc."

BPA does not adopt PGP's proposal, included in their definition of the DJ Mid-C indexes, for establishment of successor indexes. See Issue 2.

Issue 2

Whether the GRSPs should require BPA to negotiate successor indexes with customers in the event that the California ISO and/or the DJ Mid-C price indexes cease to exist.

Parties' Positions

PGP proposes language for the GRSPs that would require that any successor index to the DJ Mid-C Indexes will be established "as agreed by the Customer and BPA." Knitter *et al.*, WP-02-E-PG-01, at 7; PGP Brief, WP-02-B-PG-01, at 8-9. PGP asserts that "(t)he Administrator's proposed method for selecting a successor index to the Mid-C index leaves open the possibility that Bonneville will unilaterally select an index at a location where a given customer cannot conduct business due to transmission restraints. This could result in BPA overcollecting from that customer, thus violating the standard that BPA's rates be based on cost of service." PGP Ex. Brief, WP-02-R-PG-01, at 12.

BPA's Position

BPA believes it is practical and equitable to rely on the language in the GRSPs presented in the initial proposal for selecting successor indexes for the Unauthorized Increase Charges and Excess Factoring Charges, specifically those provisions that identify the PX price indexes or "any applicable new hourly or diurnal energy index at a hub at which Northwest parties can trade . . ." Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 109; Keep *et al*., WP-02-E-BPA-43, at 32.

Evaluation of Positions

PGP quotes section 7(a) of the Northwest Power Act, which provides that BPA's rates must assure repayment of the FCRPS over a reasonable period of years. PGP Ex. Brief, WP-02-R-PG-01, at 12-13. PGP contends that under BPA's proposal "there is a potential that any given Bonneville customer may not be able to trade on the index chosen by Bonneville." *Id*. at 13. PGP claims that BPA's proposed selection of a successor index(es) would vest BPA with "unbridled discretion" to set rates outside the power rate case, customers would be without assurances that they will be able to switch to the successor index, and Bonneville may develop rates that are not cost-based. *Id*.

PGP provides no proposal for implementing its suggested provisions that any successor index(es) be established "as agreed by the Customer and by Bonneville." This suggested provision, if triggered by developments in the DJ Mid-C or California ISO indexes, could require BPA to individually negotiate successor indexes with each customer and result in an inconsistent administration of the UAI Charges and Excess Factoring Charges.

BPA includes sufficiently precise language in its GRSPs to assure a reasonable establishment of successor indexes for its UAI Charges and Excess Factoring Charges, should the need arise. BPA specifically identifies the PX indexes as one potential successor index for the UAI Charges for energy and Excess Factoring Charges, and otherwise specifies characteristics of successor indexes. Significantly, one of the characteristics required for any successor index in the GRSPs is that the price index reflects transactions "at a hub at which Northwest parties can trade." Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 92-94, 108-109. BPA does not agree that selection of a successor index should be based on negotiations with customers. Keep *et al*., WP-02-E-BPA-43, at 32. Such a scenario could delay billing for UAI Charges or other affected charges (such as those for Excess Factoring) until such time as negotiations with customers are complete. *Id*. Furthermore, PGP's proposal presents some potential scenarios in which negotiations, if completed individually with each customer, yield agreements utilizing differing successor indexes. *Id*. This would result in an inconsistent set of effective penalty charges affecting BPA's customers. *Id*.

PGP's contention that BPA's selection of a successor index may result in "rates that are not cost-based," PGP Ex. Brief, WP-02-R-PG-01, at 13, ignores the central intent of the UAI Charges and Excess Factoring Charges. Those charges are designed as penalty charges rather than cost-based charges, with the primary intent of deterring customers from exceeding their contractual right with regard to the amount and shape of load placed on BPA. The deterrent nature of these charges and other considerations behind their design are addressed at length in the Rate Design chapter. *See* sections 10.6 and 10.7.

PGP's argument that BPA could unilaterally select an index at a location where an individual customer may not be able to conduct business is misplaced and without merit. The language in BPA's proposed GRSPs regarding successor index(es) states it would be based on transactions at "a hub at which Northwest parties can trade." Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 109; Keep *et al*., WP-02-E-BPA-43, at 32. This provision simply ensures that any successor indexes would be representative of power prices traded at a hub(s) within the Northwest, such as the DJ Mid-C Indexes, or a hub(s) or delivery point(s) bordering on the Northwest, such as the specific California ISO indexes proposed for the Excess Factoring Charges and UAI Charges. It is unreasonable and unnecessary to require that trading locations represented by any successor index to be accessible to each individual customer. First, there may not be a potential successor index accessible to all customers. In fact, it may be that some customers, due to transmission constraints or other reasons, cannot currently trade at the hub represented by the DJ Mid-C Indexes; indeed, neither PGP, nor any other party has presented evidence to the contrary. However, no party has argued that BPA ascertain every customer's accessibility to power trades at location represented by the DJ Mid-C Index before implementing its proposed penalty charges. Secondly, BPA's selection of the DJ Mid-C Indexes and the California ISO indexes were driven by a need to ensure a deterrent against unauthorized increases and excess factoring, Tr. 1213, and protection against BPA cost exposure, Keep *et al.*, WP-02-E-BPA-43, at 32, Tr. 1212, and a deterrent against arbitraging, Tr. 1214. Further, BPA designed its penalty charges in a fashion that would motivate customers to purchase appropriate products in advance rather than to place unauthorized increases or excess factoring burdens on BPA's system. Keep *et al.*, WP-02-E-BPA-17, at 25-26; Keep *et al.*, WP-02-E-BPA-43, at 33; Tr. 1214. PGP's arguments ignore the reasons that compel the selection of relevant indexes that accomplish the objectives intended by BPA's proposed penalty charges. PGP's contention that individual customers be able to trade at any successor index that may be adopted in the future for the UAI Charges and/or the Excess Factoring Charge constitutes an unreasonable and irrelevant standard for selection of successor indexes.

Decision

BPA rejects PGP's proposal for selection of successor indexes. BPA has adopted the GRSP language included in the initial proposal for establishing successor indexes for the UAI Charges. BPA also has adopted the GRSP language included in the initial proposal for establishing successor indexes for the Excess Factoring Charges.

17.2.2 Low Density Discount (LDD)

In BPA's initial proposal, BPA advocated a Benefits Legislation Exclusion and included it as part of the description of the LDD in the GRSPs. Gustafson and Thompson, WP-02-E-BPA-23, at 5; Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 101-102. Numerous parties opposed the adoption of a Benefits Legislation Exclusion. PNGC Brief, WP-02-B-PN-01, at 22; NRU Brief, WP-02-B-NI-02, at 19-20; PPC Brief, WP-02-B-PP-01, at 43-44. In response, in its rebuttal testimony, BPA proposed that it is unnecessary at this time to include a Benefits Legislation Exclusion in the description of the LDD. Gustafson *et al.*, WP-02-E-BPA-48, at 2-3. This issue is addressed in detail in ROD section 10.12 at Issue 6.

In the initial proposal, BPA identified the following rate schedules as eligible for the LDD: the PF Preference rate, the PF Exchange Program rate, the PF Exchange Subscription rate, the RL-02 rate, and the NR-02 rate. Gustafson and Thompson, WP-02-E-BPA-23, at 2-3. In rebuttal testimony, BPA proposed that the LDD not apply to the RL-02 rate and the PF Exchange Subscription rate. Gustafson *et al.*, WP-02-E-BPA-48, at 9-10. PacifiCorp argues that BPA should apply the LDD to both the RL rate and the PF Exchange Subscription rate. PacifiCorp Brief, WP-02-B-PL-01, at 7-9. This issue is addressed in detail in ROD section 10.12 at Issue 10.

In the initial proposal, BPA proposed to eliminate the Additional Adjustment for Very Low Densities. Gustafson and Thompson, WP-02-E-BPA-23, at 3. Numerous parties argued that BPA should retain the Additional Adjustment for Very Low Densities. Saven *et al.*, WP-02-E-NI-02, at 3-6; Thayer *et al.*, WP-02-E-PN-03, at 2-5; Hansen and O'Meara, WP-02-E-PP-08, at 2-3. In its rebuttal testimony, BPA concluded that the parties' arguments were well-reasoned. Based on those arguments, BPA will continue the Additional Adjustment for Very Low Densities for the next rate period. Gustafson *et al.*, WP-02-E-BPA-48, at 2. This issue is addressed in detail in ROD section 10.12 at Issue 1.

In the initial proposal, BPA did not specify whether or not the LDD would apply to the Slice product. In an errata to the Wholesale Power Rate Schedules, WP-02-E-BPA-07(E5), BPA clarified that the LDD would apply to Slice and provided a description of how the LDD for Slice would be determined. PNGC argued that there are problems with BPA's approach and proposed refinements. PNGC Brief, WP-02-B-PN-01, at 22-23. In its testimony, BPA proposed further refinements to this approach. Gustafson *et al*., WP-02-E-BPA-48, at 4. This issue is addressed in detail in ROD section 10.12 at Issue 8.

17.3 Transmission Resale

Issue

Whether the GRSPs should include language acknowledging that PBL may resell surplus transmission capacity.

Parties' Positions

MAC states that PBL should be able to remarket unneeded transmission capacity. MAC Brief, WP-02-B-MA-01, at 14-15.

BPA's Position

BPA proposed language to be included in the GRSPs that would acknowledge PBL's ability to resell surplus transmission capacity, and set some criteria for such resales. Wholesale Power Rate Schedules, WP-02-E-BPA-07(E2). *See* Pedersen and McRae, WP-02-E-BPA-28, at 3.

Evaluation of Positions

MAC states that "there is excess demand for summer intertie capacity, as evidenced by the number of requests on the BPA OASIS that have been denied for lack of Available Transmission Capacity on the intertie. Thus, the PBL should be able to remarket these unneeded rights. There is apparently nothing on the record which states that the PBL cannot remarket these unneeded rights, and any such limitation would violate the point-to-point tariff." MAC Brief, WP-02-B-MA-01, at 14-15.

Sometimes PBL purchases more transmission capacity than it can use for its market sales. Pedersen and McRae, WP-02-E-BPA-28, at 3. PBL must often purchase transmission capacity long before executing market sales agreements; thus, it is difficult to precisely match transmission purchases with market sales deliveries. *Id.* During the FY 2002-2006 rate period, PBL intends to offer surplus transmission capacity for resale. *Id.* Therefore, PBL will include the following clarifying language in the final proposal GRSPs, section I.E., "Provision for Reassignment of Surplus Transmission Capacity":

> PBL may reassign transmission capacity that it has reserved for its own use at a price not to exceed the highest of: (1) the original transmission rate paid by PBL; or (2) the applicable transmission provider's maximum stated firm transmission rate on file at the time of the transmission reassignment. Except for the price, the terms and conditions under which the reassignment is made shall be the terms and conditions governing the original grant by the transmission provider. Transmission capacity may only be reassigned to a customer eligible to take service under the transmission provider's open access transmission tariff or other transmission rate schedules.

Wholesale Power Rate Schedules, WP-02-E-BPA-07(E2). This language is modeled on language approved by FERC in *Enron Power Marketing, Inc.*, 81 FERC ¶ 61,277, at 62,361 (1997). In *EPMI*, the Commission notified all jurisdictional power marketers that their existing rate schedules were thereby amended to include language similar to that above in order to authorize those marketers to engage in transmission capacity reassignments without the necessity of making individual filings. *Id.* BPA includes this language to make clear PBL's authority to resell excess transmission capacity.

Decision

The GRSPs include language acknowledging that PBL may resell surplus transmission capacity.

17.4 Cost-Based Indexed IP Rate Option

The indexed rate option proposed by BPA for use by aluminum smelter DSI customers is tied to the London Metals Exchange Aluminum H.G. 3-month (LME 3-month) futures contract (US$). This Indexed Rate will be set the same day the purchaser elects the Indexed Rate option. Three main features describe the Indexed Rate: (1) the "midpoint" or point where the LME 3-month price intersects $23.50/MWh ($25.00/MWh for some purchasers) on the rate curve; (2) a "lower pivot point" of $19.00/MWh ($20.50/MWh), the point where the price of energy remains unchanged as the price of aluminum continues to drop; and (3) an "upper pivot point" of $28.50/MWh ($30.00/MWh), the point where the price of energy remains unchanged as the price of aluminum continues to rise. BPA's official aluminum price forecast used to set the indexed rate midpoint shall be based on the average of aluminum forward price swap quotes received by BPA on the day of pricing, plus a risk premium of up to 2 cents. This midpoint may not be set above 74 cents/lb. aluminum or below 66 cents/lb. aluminum. The rate of change on the rate curve from the midpoint to the lower pivot point will be $.75/MWh for every 1 cent/lb. drop in aluminum price. From the midpoint to the upper pivot the rate of change will be $.833/MWh for every 1 cent/lb. rise in aluminum price. Power prices under this rate will be rounded to the nearest $1/10^{th}$ or $0.1/MWh. Once selected, this rate shall remain in effect for the entire contract period. *See, generally,* Miller *et al*., WP-02-E-BPA-46.

The parameters used to calculate the monthly price shall be as follows:

The entire month's closing bid prices (second ring) of the LME 3-month futures contract shall be used to calculate the average aluminum price each month. The average aluminum price each month will be rounded to the nearest 1/10 cent ($0.001). The rate for the month shall be establish by applying this average to the IP cost-based index rate curve established at the time the customer elected the indexed rate option. Each month's rate is likely to vary due to fluctuations in underlying LME aluminum prices.

An indexed rate will also be available, at BPA's discretion, to non-aluminum smelter DSIs. Any indexed rate offered to non-aluminum smelter DSI customers will be designed to recover the equivalent of $23.50/MWh over the rate period, and must be based on a commodity that is a direct product of the purchaser. This commodity must be tied to a commercially recognized price index that is: (1) relied on by multiple producers; (2) used commercially to set settlement terms between producers and consumers; and (3) used for establishing longer term prices and for hedging. *See, generally*, Miller *et al*., WP-02-E-BPA-46

17.5 Nonfirm Energy Rate (NF-02)

In the initial proposal, BPA modified the NF rate schedule, NF-02, by deleting the following sentence from the Rates, Billing Factors, and Adjustments section: "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." Procter, WP-02-E-BPA-31, at 1.
The NF rate was subject to the NF Rate Cap beginning October 1, 1987, for 12 years. *See* 1996 Wholesale Power and Transmission Rate Schedules, DOE/BP-2921, at 136. The NF Rate Cap defined the maximum nonfirm energy price for general application during each month. *Id*. The level of the NF Rate Cap was based on a formula tied to BPA's system cost and California fuel costs. *Id*.

In the initial proposal the following sentence was deleted: "For purchases under [the] NF-96 rate schedule, transmission service shall be charged under the applicable transmission rate schedule." Procter, WP-02-E-BPA-31, at 1. The Unauthorized Increase Charge was added to the list of Adjustments, Charges, and Special Rate Provisions. *Id*. at 3. The word "minus" was substituted for the word "less" in the following phrase in section III.C.3, Incremental Rate: " . . . that has an Incremental Cost greater than the Standard rate . . . *minus* 2 mills." *Id*. (Emphasis added.) The average cost of nonfirm energy also was updated, using the same methodology as was used for the NF-96 rate. *Id*. The CRAC is not applicable to the NF rate schedule. The correct title for the NF-02 rate is Nonfirm Energy rate.

No party raised any issues regarding the NF rate in testimony or on brief. Therefore, BPA's final 2002 power rate proposal includes the language changes described above.

17.6 Discontinued Rates

Issue

Whether BPA should discontinue the Reserve Power (RP-96) rate and the Power Shortage (PS-96) rate.

Parties' Positions

No parties addressed this issue in briefs or testimony.

BPA's Position

BPA's initial testimony stated that the RP-96 rate and the PS-96 rate are being allowed to expire. Procter, WP-02-E-BPA-31, at 2. BPA proposed no replacement rate schedules for the reserve power or power shortage rates in the 2002 power rate case.

Evaluation of Positions and Decision

The RP-96 rate superseded the RP-95 rate. 1996 Wholesale Power and Transmission Rate Schedules, at 57. At this time, however, there are no existing contracts for which the RP rate schedule is applicable. Procter, WP-02-E-BPA-31, at 2. In the future, if BPA wishes to enter into the same type of sale, it would use the FPS-96 rate schedule. *Id*. Similarly, the PS-96 rate superseded the PS-95 rate. 1996 Wholesale Power and Transmission Rate Schedules, at 59. The PS rate is being allowed to expire because the Share-the-Shortage Agreement, for which the PS rate was developed, has expired. Procter, WP-02-E-BPA-31, at 3. Because no party raised any issues regarding the reserve power or power shortage rates on brief, this issue is withdrawn in accordance with §1010.3 of the *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7611 (1986).

17.7 Slice Product Costing and True-Up Adjustment Charge Tables

Issue

Whether BPA should make changes to the tables for Slice Product Costing and Basis for Slice True-Up Adjustment Charge.

Parties' Positions

SPG proposed that BPA use a single table that combines the Slice Product Costing table and Basis for True-Up Adjustment Charge table (*see* Mesa *et al.*, WP-02-E-BPA-32, Attachment 1, at 24, and Attachment 2, at 25, respectively). Carr *et al.*, WP-02-E-SG-01, Attachment 6. This single table would provide the necessary connections between BPA's ratesetting and accounting systems, and would replace BPA's two tables in the GRSPs. Carr *et al.*, WP-02-E-SG-01, at 11.

<u>BPA's Position</u>

BPA agreed in its rebuttal testimony that it would be acceptable to combine the Slice Product Costing table and the Basis for True-Up Adjustment Charge table. Mesa *et al.*, WP-02-E-BPA-54, at 8. In addition, BPA has added line items in the newly combined table (*see* Table 1 in Slice Methodology, ROD Attachment 1) that will account for traditional Residential Exchange costs (if any); cash payments BPA makes for the settlement of the REP; hedging costs associated with the Inventory Solution; Initial Implementation Expenses; and other Implementation Expenses associated with the development of the Slice product.

<u>Evaluation of Positions</u>

BPA agrees with SPG's suggestion to combine the Slice Product Costing table and the Basis for the True-Up Adjustment Charge table. BPA has combined the two tables, and the new table is displayed as Table 1 in Attachment 1 of this ROD. The new table is entitled, "Slice Product Costing and True-Up Table." This table contains sample values and will be an attachment to the Slice Methodology, which BPA will submit to FERC for 10-year approval. This table also will replace Table E of the GRSPs. *See* Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 124. Table D of the GRSPs will be deleted. *See Id*. at 103.

BPA inserted additional line items in the Slice Product Costing and True-Up Table to be consistent with the decisions in this ROD. BPA inserted a line item for prospective Inventory Solution Hedging Activities (*see* line 59); a line item for Net Residential Exchange Costs (*see* line 75) in the event that some IOUs do not accept a settlement for the Residential Exchange; and line items for Slice Initial Implementation Expenses and other Implementation Expenses (*see* lines 78 and 79) associated with development of the Slice product. BPA moved the Subscription Settlement Costs (actual cash payments made by BPA under the new Residential Purchase and Exchange Agreements) out of the Net Cost of the Inventory Solution, to the PBL Costs (*see* line 76). This move does not affect the resulting monthly Slice rate per percent of the Slice System, and it allows for true-up for whatever the net cost of the settlement of the REP would be. *See* Mesa *et al*., WP-02-E-BPA-54, at 9. Slice purchasers would pay their share of these costs through the annual Slice True-Up process. BPA inserted a line item, "Minimum Required Net Revenues" (*see* line 72). BPA also added column labels A through F to the table. *See* WP-02-A-01(E1).

<u>Decision</u>

As proposed by SPG, BPA combined the Slice Product Costing Table and the Basis for True-Up Adjustment Charge table into a single table, the Slice Product Costing and True-Up Table.

18.0 PROCEDURAL MATTERS

18.1 <u>Evidentiary Issues</u>

18.1.1 <u>Scope of Cross-Examination</u>

<u>Issue</u>

Whether the testimony of BPA witness Mark Ebberts should be stricken because the IOUs did not receive a reasonable opportunity for cross-examination.

<u>Parties' Positions</u>

The IOUs argue that BPA violated section 7(i) of the Northwest Power Act by failing to provide parties a "reasonable opportunity for cross examination" on the issue of whether revenue taxes should be included in the industrial margin. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 96. The IOUs believe the witness had insufficient knowledge and understanding of the issues, and as a consequence, they should have been provided an opportunity to cross-examine a BPA attorney who had advised the witness on the issue of whether revenues should be included in the margin. *Id*.

<u>BPA's Position</u>

BPA believes that the IOUs' argument is without foundation when viewed in light of the entire record in this proceeding. The witness in question was cross-examined for 14 hours over a 3-day period. Tr. 1691-2079. The IOUs were provided with every piece of evidence, factual or otherwise, to which they were entitled, and the parties were not entitled, in any circumstance, to cross-examine a BPA attorney. *Id*.

<u>Evaluation of Positions</u>

Section 7 of the Northwest Power Act provides, in part, that "the hearing officer, *in [her] discretion*, shall allow a reasonable opportunity for cross examination, which, *as determined by the hearing officer*, is not dilatory, in order to develop information and material relevant to any such proposed rate." 16 U.S. §839e(i)(2)(B) (emphasis added). Originally, two weeks were scheduled for cross-examination, one week for examination of BPA's witnesses, and one week for examination of the parties' witnesses. As the record shows, BPA's witnesses were cross-examined for the entire two weeks. BPA waived cross-examination of other parties.

The BPA witness at issue here, Mr. Ebberts, was on the stand during 3 of the 10 days of cross-examination of BPA's witnesses. Tr. 1691-2079. Yet, the IOUs claim that this was insufficient opportunity for "reasonable" cross-examination. When Mr. Ebberts stated that he relied, in part, on advice of counsel on the matter of whether revenue taxes were typical for purposes of the margin, the IOUs demanded to know the basis for the advice provided to the witness. Tr. 1321. While BPA protested that the sole basis for the advice was commonly available legal authorities and that the issue should be preserved for the briefing stage of the proceeding, the Hearing Officer disagreed. *Id*. at 1324-26. She ordered that BPA provide the basis for the advice that Mr. Ebberts relied upon. *Id*. at 1328. BPA complied fully with this order. *Id*. at 1537-39.

Yet, this too, according to the IOUs, was insufficient, and they filed a motion to strike that portion of Mr. Ebberts' testimony relating to revenue taxes on the grounds that Mr. Ebberts did not qualify as an expert in the field of utility taxation or revenue taxes. BPA has been clear that the 7(c)(2) Margin Study does not require specific expertise in matters of revenue taxation. The study is conducted for purposes of calculating the typical retail margin in response to specific statutory rate directives. Ebberts, WP-02-E-BPA-22, at 2; Tr. 1696-97. The Hearing Officer denied the PacifiCorp motion, stating in part that she had "no authority to grant the relief requested by PacifiCorp." Tr. 1993.

Thereafter, the IOUs argued that, in order to satisfy the statutory provisions, they were entitled to cross-examine BPA's attorney on the issue of revenue taxes. The Hearing Officer disagreed:

> HEARING OFFICER EDWARDS: I think this matter has been totally blown out of proportion and does not carry the import that Ms. Jacklin [attorney for the IOUs] seems to think it has. The special rules she just referred to are never intended to apply to legal counsel and their work . . . If what you are trying to do is establish the fact that counsel did not research every state in order to come up with the conclusion that he purportedly gave to the witness, that can be determined through your own legal work and argued as a point on your brief. There is no point in dragging this through any more to get someone to admit as to what they did, what they did not do, what they looked at, what they did not look at.
>
> I was very concerned when I asked you before the break what you were intending to do with this testimony, and you said you intended to impeach Mr. Wright [BPA's attorney]. Now, Mr. Wright is not a witness in this case, so the only purpose for putting him on the stand would be to cause him personal embarrassment and discredit his professional reputation in a public forum. I am not going to allow you to do that for that purpose.
>
> Attorneys are only put on the stand under very extraordinary circumstances. When that happens, they are normally required to retire as counsel of record in so doing. I see nothing here that is going to aid you in that when the issue with respect to which states impose utility revenue taxes can be answered and addressed easily by any attorney in this room . . .
>
> You spent a lot of time examining the witness. You know what he did and you know what he did not do. You have all of the record testimony. You have numerous data requests you've entered that indicate that. If you are going to attack the underlying use and application of the typicality test, you have a lot of examination on the record to help you do that . . .

> I am not going to allow you to put Mr. Wright on the stand. There is no purpose for it. It will only cause more delays. I am just not going to allow it to happen.

Tr. 2091.

Thus, there are two separate issues posed for review by the Administrator: (1) whether Mr. Ebberts was sufficiently qualified as a witness so that his testimony should not be stricken; and (2) whether the parties had any right to cross-examine Mr. Wright, a BPA attorney.

With respect to the first issue, the Administrator's decision with regard to the issue of revenue taxes, as delineated in section 15.2.1 of this ROD, indicates that the Administrator believes Mr. Ebberts was sufficiently qualified to provide testimony relevant to all of the issues surrounding the section 7(c)(2) rate directives. His qualification statement, WP-02-Q-BPA-18, indicates that Mr. Ebberts has sufficient education, skill, training, and experience to serve as a witness in that capacity. Mr. Ebberts need not have any particular expertise in utility taxation simply because one of the issues pertains to whether revenue taxes should be included in the margin. BPA has stressed from the beginning its belief that the issue must be dealt with primarily as a legal issue. To that extent, it would have been inappropriate under the procedural rules for Mr. Ebberts to offer testimony on a legal issue. *See Special Rules of Practice to Govern this Proceeding*, WP-02-O-01, at 6. For the remainder, those limited factual issues necessary to make the determination were well within Mr. Ebberts' professional expertise, and those facts were made available to the parties through testimony and exhibits.

With regard to whether the parties have a right to question a BPA attorney, the Administrator finds that the Hearing Officer acted properly. Hearing Officer Edwards articulated a number of sound reasons for her decision, as cited above. Based on that reasoning, the Administrator believes that Hearing Officer Edwards was acting properly within her statutory discretion to define the scope of cross-examination in a manner that provides a reasonable opportunity for examination without being dilatory. There is no indication that this decision interfered with the Hearing Officer's duty "to develop a complete record." 16 U.S.C. §839e(i)(2). As a consequence, arguments to the effect that the decision denied parties statutory due process are totally without substance.

In their brief on exceptions, the IOUs pursue this line of argument once again. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 74. The IOUs "strongly object to BPA using witnesses who cannot explain the basis for the conclusions in their testimony," and go on to argue that the "witness did not perform the factual investigation and analysis that went into the testimony, nor could he explain it." *Id*. A fair reading of the record shows that such allegations are unfounded. From the outset, the IOUs have been unhappy with BPA's findings in this area, but they did not build a convincing case in support of their own conclusions. Instead, they relied on anecdotal testimony that was not entitled to significant weight or credibility. Hoff *et al*., WP-02-E-AC/GE/IP/MP/PL/PS/-03, at 19.

The IOUs also reargue their claim that the revenue tax issue is a "factual issue." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 75. It remains mystifying how the IOUs can continue to assert that they have somehow been denied "facts" necessary to determine how taxes embodied in state statutes should be treated for the purpose of a single Federal statutory provision. BPA did not find that an abundance of facts was necessary to carry out what is almost purely a question of statutory interpretation. Chapter 15 of this ROD makes it clear that a very limited number of "facts" are needed to analyze this issue. Those facts were provided in testimony. The real question is why the IOUs did not provide additional facts in their own case if they truly believed those were crucial to the outcome. They certainly had ample opportunity to do so.

Finally, the IOUs maintain once again that they should have been given an opportunity to question a BPA attorney, whom they refer to as the "undisclosed witness." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 75. As discussed above, the right of cross-examination in a BPA rate proceeding derives from section 7(i)(2)(B) of the Northwest Power Act. 16 U.S.C. §839e(i)(2)(B). The Administrator finds that the Hearing Officer provided a reasonable opportunity for cross-examination, as required by the statute, and did not exceed or abuse her discretion by refusing to permit cross-examination of BPA's attorney. Moreover, the Administrator does not understand why IOUs believe that BPA's use of the Hearing Officer's directly quoted ruling from the bench somehow "giv[es] the reader an erroneous impression." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at n. 245.

Decision

The Hearing Officer provided the parties a reasonable opportunity for cross-examination of BPA's witnesses. The testimony of BPA witness Ebberts will not be stricken, nor were the IOUs entitled to compel the testimony of BPA's attorney.

18.1.2 1996 Power Rate Settlement Agreement

Issue

Whether BPA has breached the "no precedent" provision of the 1996 Partial Power Settlement Agreement with respect to the issues of revenue taxes, DSI floor rate, and Mid-C resources.

Parties' Positions

The IOUs argue that BPA has breached the "no precedent" provision of the 1996 Partial Power Settlement Agreement by relying on the 1996 ROD as precedent for its decision on revenue taxes, the DSI floor rate, and Mid-C resources. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 98. *See also*, IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 77.

BPA's Position

The IOUs' interpretation of the 1996 Partial Power Settlement Agreement is erroneous. Moreover, BPA has not relied on the 1996 ROD as precedent.

Evaluation of Positions

The IOUs state that the 1996 Settlement Agreement contains a clause memorializing the parties' agreement "that the *matters covered* by the Settlement Agreement would not be binding upon any parties in future proceedings, including rate cases." (Emphasis added.) IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 98. The IOUs go on to conclude that BPA has violated this covenant because it has "impermissibly and repeatedly relied upon the decisions, conclusions, and methodologies of the last case to justify some of its most controversial proposals in this proceeding." *Id*. Three areas in particular are cited: (1) the issue of whether revenue taxes should be included in the industrial margin; (2) calculation of the DSI floor rate; and (3) treatment of Mid-C resources. *Id*.

The IOU argument is flawed in three respects. First, it inaccurately defines the scope of "matters covered" by the Settlement Agreement. The Settlement Agreement provides as follows:

> No action taken or not taken by BPA, any party, or the Hearing Officers in accordance with matters covered by this Power Settlement Agreement shall serve to create any procedural or substantive precedent . . . .

Settlement Agreement, at 1. Thus, the "no precedent" provision applies only to matters covered by the settlement agreement. As noted by the Administrator in the 1996 ROD, only a limited number of provisions were covered by the settlement agreement:

> The Power Settlement provides that the parties agreeing to it also agree to the Transmission Settlement. Attachment 2, p. 3. The Power settlement also provides that the PF rate should be established at "less than 24.4 mills per kWh as shown on line 21 of Table RDS 50 of the 1996 Final Documentation to the Wholesale Power Rate Development Study." *Id*. at 2. It contains a specific proposal for assumptions relating to any underrecovery of Utility Delivery facilities' cost due to the limit on the Delivery Charge, a proposal for the adoption of the Availability Charge, and proposals relating to the computed maximum requirement waiver and Partial Load Shaping. *Id*. at 3.

1996 ROD, WP-96-A-BPA-02, at 5. This language accurately and fully tracks the provisions of the settlement document itself. *Id*. at Attachment 2. Thus, the matters covered by the Settlement Agreement do not include the three issues raised by the IOUs: revenue taxes, DSI floor rate, and Mid-C resources. Therefore, those issues are not governed by the "no precedent" clause, and the IOU argument, consequently, has no foundation.

Second, the IOUs mischaracterize the Hearing Officer's findings with respect to the Settlement Agreement. Citing the Hearing Officer's Order in response to the IOUs' Motion to Strike, WP-02-0-16, the IOUs assert the following:

> The "no precedent" clause expressly prohibits the use of conclusions from the 1996 rate case to support the reasonableness of BPA's proposal in this case, as Hearing Officer Edwards correctly concluded in her ruling on this issue . . . .

> As Hearing Officer Edwards observed, the no-precedent provision does not prevent witnesses from referring to the 1996 ROD in their testimony to provide background or context, but it does prohibit reliance on the 1996 ROD as the legal basis in support of their position.

IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 99-100. The IOUs fail to point out that the Hearing Officer clarified the scope of the order at hearing:

> Under my earlier ruling on the motions to strike, *I did not interpret the Settlement Agreement of 1996 with respect to either the precedential or binding nature of that agreement as to all issues contained in the ROD.* I merely pointed out that the right to contest clause could not be used for the particular purpose it was being raised for at that time. *The order was issued for reasons other than the arguments based upon the settlement agreement*.
>
> The meaning of the settlement agreement appears to be still in dispute as to what issues are actually covered therein. This is a legal controversy which can be addressed by the participants in their briefs.

Tr. 1992 (emphasis added). Thus, the Hearing Officer clarified that the Order relied upon by the IOUs did not interpret the settlement agreement, and particularly not in the manner now relied upon by the IOUs. The IOU arguments in this vein must therefore be disregarded.

Third, the IOUs have erroneously concluded that BPA used the 1996 ROD as precedent. As indicated elsewhere in this ROD, Mr. Ebberts did not use the 1996 ROD as precedent. *See* chapter 15, *supra*. On the issue of revenue taxes, he did adopt the methodology used in 1996--and in that sense he "relied" upon the "typicality" test used in 1996. *Id*. But he testified repeatedly during cross-examination that he did so only after reviewing historical documentation from other rate cases. Tr. 1691-2079. Thus, he exercised independent judgment and used that methodology because, in his professional judgment, it was the correct and proper way to make the determination.

Similarly, Mr. Ebberts used the IP-83 Standard rate as the basis for the floor rate, as had been done in 1996. As pointed out elsewhere in testimony, the IP-83 Standard rate has been the basis for the floor rate in every rate case since 1985. Ebberts, WP-02-E-BPA-47, at 6. Of course, it can be said that he adopted a methodology that had been used historically, but that does not mean that he used prior rate cases as precedent. In fact, when the PPC and the IOUs proposed that the Standard rate be replaced by the Premium rate, the rebuttal testimony and this ROD indicate that BPA has responded to that issue on its merits. *Id*.; *see* chapter 15, *supra*. While the Administrator has chosen to continue using the Standard rate as the basis for the floor rate, it is because, as the record shows, she has examined the evidence, listened to the arguments, and then made a reasoned policy choice to do so--not because she is bound by her predecessors' decisions.

With respect to the treatment of Mid-C resources in the 7(b)(2) rate test, the substantive decision is moot, and that renders the issue of reliance on BPA's 1996 rate case moot. *See* ROD section 13.5.

Decision

The issues cited by the IOUs were not "matters covered" by the Settlement Agreement but, in any event, BPA did not use the 1996 rate case as precedent for the decisions being made in this proceeding.

18.1.3 Official Notice

Issue 1

Whether the Hearing Officer erred in not taking official notice of certain documents designated by CRITFC/Yakama.

Parties' Positions

On March 17, 2000, CRITFC/Yakama filed a motion requesting that official notice be taken of certain documents referenced in their initial brief. WP-02-M-90. CRITFC/Yakama argue that the documents are official publications or reports of government agencies and, as such, are well known within the region, are within the expertise of BPA, and are not subject to reasonable dispute under the Federal Rules of Evidence. *Id*. CRITFC/Yakama claim that they will be prejudiced if the request is denied. *Id*.

The DSIs filed a response alleging that CRITFC/Yakama should have sought admission of the evidence prior to the close of the hearing. WP-02-M-96. The DSIs also argue that, contrary to the assertions of CRITFC/Yakama, the documents in question are highly controversial and hotly disputed. Thus, the DSIs argue that it would be inappropriate to foreclose the other parties from testing these documents by admitting them into evidence now. *Id*.

PPC also filed a response in opposition to the CRITFC/Yakama request, noting that the documents cited in testimony had been previously stricken as lacking relevance. WP-02-M-94. The remaining documents in the CRITFC/Yakama request were not available for cross-examination.

BPA's Position

BPA did not file a response to the motion, and the Administrator is addressing it for the first time.

Evaluation of Positions

The Administrator fundamentally agrees with the Hearing Officer's determination that the request for administrative notice should be denied, for the reasons articulated in Judge Edwards' Order. *See* WP-02-0-24. The Administrator is particularly concerned that "since the proceeding is now closed, admission at this time would cause prejudice to the other parties because they have had no opportunity to explain or rebut the material or to probe its reliability in any way." *Id*. at 2. Any danger of prejudice to CRITFC/Yakama is far outweighed by the potential unfairness to other parties. This is particularly true in light of the fact that CRITFC/Yakama offer no reason for the delay in seeking admission of material that contains information and assertions that are clearly the subject of much dispute in this region.

Decision

CRITFC/Yakama's request that the Administrator take official notice of the designated documents is denied.

Issue 2

Whether the Administrator should take administrative notice of IOU Exhibit B, Exhibits and Attachments of the Initial Brief of the Northwest IOUs, WP-O2-B-AC/GE/IP/MP/PL/PS-01.

Parties' Positions

The IOUs argue that the Administrator should take official notice of a document styled Electric Sales and Revenue 1997, October 1998, Energy Information Administration, DOE/EIA-0540(97), table 16. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 42; *see also*, IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 42. The DSIs argue that the request should be denied. WP-02-M-86.

BPA's Position

BPA has not taken a prior position on this issue.

Evaluation of Positions

At footnote No. 119 of the IOU Brief, and without further explanation, the IOUs request that official notice be taken of a document styled Electric Sales and Revenue 1997, October 1998, Energy Information Administration, DOE/EIA-0540(97), table 16. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 42. The DSIs filed a responsive pleading on March 1, 2000. WP-02-M-86. The DSIs argue that the report "is not an appropriate subject for official notice, and the report is not immune from the 7(i) requirement that the parties be afforded an adequate opportunity to refute 'any material submitted by any other person'. . . ." *Id*. at 2.

On March 8, the IOUs responded to the DSI motion. WP-02-M-87. They argue that the Exhibit is appropriate for either judicial or official notice. *Id*. They also argue that the report in question contains no adjudicative facts regarding the parties to this proceeding that would be appropriate for hearing and cross-examination. Rather, the IOUs claim, the DOE Report is evidence that BPA has not properly calculated a "typical" margin. *Id*. at 6. The IOUs also maintain that the report is within BPA's area of expertise, and that the DSIs have had ample opportunity to challenge the material contained in the Exhibit. *Id*.

The Administrator does not find the IOU arguments persuasive for many of the same reasons the CRITFC/Yakama request was denied. The IOUs do not provide any compelling reason why the Exhibit was not provided at an earlier stage of the proceeding, nor do they make a clear case with regard to the relevance of the material. In fact, the IOU position seems to be largely self-contradictory. The IOUs state that the Exhibit "contains no adjudicative facts regarding the Parties to this proceeding." *Id*. Yet, in the very next sentence, they claim that the same Exhibit "is evidence that BPA has not properly calculated a 'typical' margin." *Id*. Elsewhere in the same document, the IOUs purport to be offering the Exhibit in rebuttal to BPA's margin study. *Id*.

The issue of whether BPA has properly calculated the margin is one of the many legal issues being adjudicated in this proceeding. The Advisory Committee Notes for Rule 201 of the Federal Rules of Evidence refer to "non-adjudicative" facts as "non-evidence" facts. "Adjudicative" facts are described as follows:

> What, then are "adjudicative" facts? Davis refers to them as those "which relate to the parties," or more fully:
>
> "When a court or an agency finds facts concerning the immediate parties--who did what, where, when, how, and with what motive or intent--the court or agency is performing an adjudicative function, and the facts are conveniently called adjudicative facts. * * *
>
> "Stated in other terms, the adjudicative facts are those to which the law is applied in the process of adjudication. They are facts that normally go to the jury in a jury case. They relate to the parties, their activities, their properties, their business." 2 Administrative Law Treatise 353.

Rule 201, Advisory Committee Notes on 1972 Amendments. The exhibit proffered by the IOUs consists of facts which the IOUs seek to introduce as substantive evidence to show that BPA has not properly calculated the industrial margin and to rebut the study that BPA conducted in support of its margin calculation. Such facts are unquestionably "adjudicative" facts. The Advisory Committee Notes make clear that judicial notice of such "adjudicative" facts is extremely uncommon:

> With respect to judicial notice of adjudicative facts, the tradition has been one of caution in requiring that the matter be beyond reasonable controversy . . .
>
> This rule is consistent with Uniform Rule 9(1) and (2) which limit judicial notice of facts to those 'so universally known that they cannot reasonably be the subject of dispute,' those 'so generally known or of such common notoriety within the territorial jurisdiction of the court that they cannot reasonably be the subject of dispute,' and those 'capable of immediate and accurate determination by resort to easily accessible sources of indisputable accuracy.'

Id. The DSIs have convincingly argued that the Exhibit is not a proper candidate for judicial or administrative notice in this proceeding:

> The Energy Information Administration's report is certainly not self-explanatory as to how, if at all, it relates to the issue on which the IOUs seek to offer it [*i.e.*, the appropriate level of the industrial margin]. As the overview to Exhibit B notes, the consumers reflected in the report are so small they are reclassified between the commercial and industrial sectors from year-to-year based on such things as changes in demand level. Indeed, the Energy Information Administration even classifies farms as part of the industrial sector. The inappropriateness of such data is manifest. For example, the very first utility on Exhibit C is the City of Bandon, reported as having six industrial customers with total sales of 1,842 MWh. If these figures are accurate, the average hourly consumption of the six customers is 35 kW, on a percent of the size of the smallest customer treated by BPA as 'industrial.' The so called 10 industrial customers of the City of Idaho Falls are, on average, less than one-tenth the size of the average customer of the City of Bandon. Given the obvious inverse relationship between average cost per kWh and customer size . . . use of such data to determine the margin appropriate for DSIs is improper. The IOUs then present highly misleading calculations based upon the data. IOUs have exaggerated their proposed margin by uniformly understating power and transmission costs of the utilities by pretending that all of the power sold for use by the tiny industrial customers of the utilities is purchased from BPA at a 100 percent load factor. There is no reason to believe that all power reflected in Exhibits B and C is even purchased from BPA; it almost certainly is not. Finally, the IOUs have also excluded from Exhibit C six utilities that in aggregate serve a substantial proportion of large industrial load in the region.

WP-02-M-86. The DSIs have raised substantial questions regarding the relevance of the Exhibit for the purpose for which it is being offered. Moreover, the DSIs' analysis has shown convincingly that the probative value of the Exhibit could have been tested on many levels by subjecting it to the rigors of the hearing process, where the parties would have had the opportunity to present rebuttal and conduct cross-examination. Despite the IOUs' assertions that the parties have had adequate opportunity to test the Exhibit, these traditional avenues of exploring the evidentiary facts would be totally denied to the parties were the request for taking official notice granted.

In their brief on exceptions, the IOUs make the following observation:

> BPA appears to misunderstand the purpose of requesting official notice of the Electric Sales and Revenue Report. It is not offered for the purpose of establishing in this proceeding an industrial margin based on data in the report. *That margin can be set correctly using data available on taxes in the sample contained in BPA's Industrial Margin Study* . . . At a minimum, the report should officially be noticed for the limited purposes of demonstrating that there are Northwest utilities outside of Washington and Oregon with industrial load, and to

> evidence that the industrial margins reported by DOE appear to be far higher than that proposed by BPA. The DOE report simply provides a basis to question the reasonableness of the margin proposed by BPA.

IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 77 (emphasis added). This statement appears to be a significant departure from the IOUs' earlier representations that the report was submitted for the purposes of "rebuttal to the data in the BPA confidential report" and as "evidence that BPA has not properly calculated a "typical" margin. Northwest IOUs' Answer to Motion of the DSIs to Strike, WP-02-M-87, at 2, 6. Regardless of this apparent inconsistency in the IOU position, the fact remains that the IOUs did not attempt to use this material during the evidentiary phase of the proceeding, or request official notice at that time, in spite of having every opportunity to do so. Instead, they waited until the evidentiary record was closed. The Administrator sees no excuse for the delay and finds that taking official notice at this stage of the process would deprive other parties of the right to present evidence in rebuttal. *United States v. Abilene & S. Ry. Co.*, 265 U.S. 274, 289 (1924); *see also*, *Sarria-Sibaja v. INS*, 990 F.2d 442 (9^{th} Cir. 1993) and Stein *et al*., Administrative Law at §25.03.

Decision

The IOUs' request that the Administrator take official notice of Exhibit B is denied.

18.1.4 Waiver of Attorney-Client Privilege

Issue

Whether the testimony of Burns and Elizalde, WP-02-E-BPA-37, dealing with whether there is a legal obligation to serve the DSIs, should be stricken because the witnesses waived the attorney-client privilege.

Parties' Positions

Alcoa/Vanalco argue that the testimony should be stricken because the witnesses waived the attorney-client privilege. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 24; *see also*, Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 94. Moreover, as a remedy for this waiver, these parties demand that BPA adopt the position that BPA does have an obligation to serve the DSIs. *Id*.

BPA's Position

Alcoa/Vanalco are incorrect. There was no waiver of attorney-client privilege, and the requested remedy would be inappropriate in any event.

Evaluation of Positions

Alcoa/Vanalco have challenged the testimony of BPA's policy witnesses, maintaining that BPA has used the attorney-client privilege as both a "sword" and a "shield." A more accurate characterization would simply acknowledge the challenged statements as roadmaps charting the course of the hearing from development of the factual record through briefing of legal issues. Alcoa/Vanalco's overly technical approach to strategy has been counterproductive in the context of this administrative rulemaking. With regard to the specific issue of attorney-client privilege, the arguments made by Alcoa/Vanalco do not promote an exchange of views, but only serve to make parties more wary and less open. The Hearing Officer put it well:

> To begin with, I want to point out that the kinds of statutory obligations that we are talking about here with respect to Northwest Power Act and other things are obligations that have been in existence for many, many years, and have been litigated over and over again, and are currently constantly under discussion between counsel. This is not something new for which a witness' position is going to bring any kind of surprise to any other party. So the type of surprise you are talking about here is not a compelling reason to compel testimony because it is something new which counsel could not have anticipated and did not already have a well-formed opinion with respect to. The testimony references here are merely statements that counsel advised the witness with respect to a legal position taken from one of those statutes.
>
> The questions here today, right from the beginning, objections were properly raised by BPA's counsel, from the very beginning, to the nature of this testimony. The question I permitted to be allowed was one that went to the form of the question, that is, Was your advice oral or written? That was the question I permitted. Counsel then proceeded to go into other areas, trying to force the witness to comment specifically as to those conversations, regardless of the form, and objections had been raised.
>
> *I won't allow this line of questioning to continue. I am going to rule that BPA has not waived any privilege with respect to this matter and instruct counsel to get off this program of trying to argue legal interpretations of statutes, policymaking decisions or other such things with witnesses who are not competent to render that kind of legal analysis.*
>
> You may disagree with the witness' conclusion, and you can argue the law in your brief, but let us not do it here through these witnesses. That is improper. Now, let us move on.

Tr. 102 (emphasis added). This ruling is clearly within the scope of the Hearing Officer's statutorily defined duties: "[T]he hearing officer, in [her] discretion, shall allow a reasonable opportunity for cross-examination, which, as determined by the hearing officer, is not dilatory . . . ." 16 U.S.C. §839e(i)(2)(B).

Apart from the issue of whether there was any waiver of the attorney-client privilege, the procedural rules are clear that the Hearing Officer cannot order BPA to disclose anything that it would not be required to disclose under the Freedom of Information Act. *Rules of Procedure Governing Rate Hearings* §1010.8(f). Clearly, the discussions that Alcoa/Vanalco wished to probe in cross-examination would be protected by the deliberative process exemption. 5 U.S.C. §552(b)(5). In ruling that certain of its communications were privileged under the deliberative process exception, FERC determined that there was "no unfairness to outside parties in the mere fact that the Commission employees who sometimes act as advisors and sometimes as trial counsel may, as a result, have greater access to policy views and discussion within the Commission." *McDowell Co. Consumers Council v. American Electric Power*, 23 FERC ¶61,142 at 61,321 (1983). The situation at Commission proceedings is analogous to a BPA rate proceeding. BPA is ultimately the decisionmaker, but BPA officers, staff, and attorneys act as trial staff while continuing to perform other roles and carry out other duties for the agency. Similarly, there was no action by BPA or harm to Alcoa/Vanalco sufficiently serious to warrant a waiver of the deliberative process privilege. As FERC stated:

> [W]e fail to see how [parties] will be prejudiced if the papers are withheld from the company. [They] will still have all the procedural rights to which parties are normally entitled in an administrative proceeding. Our final decision will, of course, be based on the record to be developed during the hearing. [Parties] will be unable to probe the internal deliberative process of [the agency], but this is precisely the purpose of the privilege.

Id. This reasoning applies with equal force to Alcoa/Vanalco's assertions regarding the testimony of Burns and Elizalde. The issue of attorney-client privilege therefore must give way to the agency's need to promote full and frank internal discussions on issues of public policy.

Moreover, the issue of whether BPA has an obligation to serve the DSIs is a question of statutory interpretation, a pure question of law. It was not an appropriate subject for cross-examination, or a proper subject for the witnesses to deal with in testimony. *Rules of Procedure Governing Rate Hearings* §1010.8(f). It is an issue that has been argued on brief in this proceeding, and will be argued in the courts, if necessary, by those who have the proper credentials to make such arguments. This is true irrespective of whether there was a technical waiver of the attorney-client privilege. Alcoa/Vanalco's request for relief only underscores the futility of its entire line of reasoning by asking that the Administrator "disregard any testimony or advocacy by BPA suggesting there is no obligation to serve the DSIs, and issue a ROD that confirms the obligation to sell power to the DSIs." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 27; *see also* Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 94-99. The statement is a *non sequitur*. The testimony of a fact or policy witness is not necessary to support a reasonable interpretation of a statutory provision, nor can it be used to compel a specific interpretation for the benefit of one particular class.

Thus, even if the testimony were stricken, it would change nothing. Additionally, it would be improper for the Administrator to simply adopt the Alcoa/Vanalco opinion on this issue as a "remedy." Doing so would be an inappropriate delegation of her statutory responsibility.

Furthermore, the question of whether BPA has an obligation to serve the DSIs is not a rate issue. Consequently, it need not be decided pursuant to a section 7(i) hearing. As a result, Alcoa/Vanalco are not entitled to any of the procedural requirements of section 7(i) with respect to resolution of this issue, including the right to discovery or cross-examination. It follows, as a matter of course, that since the issue is not subject to these procedural requirements, then Alcoa/Vanalco cannot be entitled to any remedy for an alleged procedural defect.

Moreover, there has been no final decision regarding the issue of whether BPA has an obligation to serve the DSIs, and such a decision can not be forced upon the Administrator through procedural maneuvering in a hearing where the issue will not be decided. Finally, the issue itself is moot for the time being because BPA is proposing to serve the DSIs. *See* ROD chapter 15.

Decision

There was no waiver of attorney-client privilege. Alcoa/Vanalco's request that the testimony of Burns and Elizalde be stricken is denied.

18.1.5 Validity of Evidence Pertaining to the Industrial Margin

Issue

Whether BPA's margin sample and the testimony of Mark Ebberts should be stricken.

Parties' Position

Alcoa/Vanalco argue that Mr. Ebberts' testimony should be stricken because he is unqualified as an expert. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 31-32; *see also*, Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 99-110. Moreover, Alcoa/Vanalco claim, the entire BPA margin study should be disallowed because it is flawed and biased and therefore inadmissible. *Id*.

BPA's Position

BPA has not had an opportunity to take a prior position on this issue.

Evaluation of Positions

Motions to strike must be raised during the hearing itself as specified in the procedural schedule. §1010.11(e). Thereafter, parties may request review of the Hearing Officer's decision by the Administrator. Alcoa/Vanalco did not raise these issues by motion during the hearing, and they are therefore waived.

Moreover, the arguments are without merit. Mr. Ebberts, as indicated elsewhere in this ROD, is qualified as an expert on the industrial margin calculation. WP-02-Q-BPA-18; *see* chapter 15, *supra*. Similarly, the margin study has been conducted in a manner that is consistent with past margin studies. Ebberts, WP-02-E-BPA-22, at 3-4. The evidence in both instances is relevant, the standard required for admission under the procedural rules. Alcoa/Vanalco's arguments really go to the weight and sufficiency of the evidence, and such concerns can be properly framed as legal arguments. It is not proper, however, to use such issues as a vehicle to strike testimony that is obviously relevant and thereby attempt to cloud the unmistakable fact that the parties requesting relief made no serious effort to build a substantive case of their own.

In their brief on exceptions, Alcoa/Vanalco reargue this issue, alleging that Witness Mark Ebberts is unqualified and his testimony inherently biased and unreliable. With respect to Alcoa/Vanalco's attacks on Mr. Ebberts' competence as a witness, the competency of a witness to testify at an administrative hearing rarely arises and when it does, it is usually resolved as a matter of credibility or weight to be given the testimony. Stein *et al*., Administrative Law at §27.04. The reason for this approach is that in most administrative hearings, including a section 7(i) hearing, the standard for admissibility is whether evidence is relevant, material, and not unduly repetitious.

An administrative factfinder enjoys wide discretion in assessing the probative value of expert opinion testimony. Stein *et al*., at §28.03. Contrary to Alcoa/Vanalco's assertions, the Administrator finds Mr. Ebberts to be fully qualified to be an expert in this area. Alcoa/Vanalco draw the line so narrowly that very few people, whether at BPA or anywhere else, could qualify. Mr. Ebberts has many years of experience as a BPA employee, and his educational credentials are impressive. Yet, Alcoa/Vanalco claim that he "lacks the education and experience that one would expect." Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 104. As to the specific examples culled from the transcript to buttress their case, the Administrator finds those inconclusive at best and at worst misleading.

Decision

The Administrator will not strike the industrial margin sample or the testimony of Mark Ebberts and finds further that they should be afforded considerable weight.

18.1.6 Admissibility of Newspaper Article

Issue

Whether BPA should reverse the Hearing Officer's order striking limited testimony from the prefiled testimony of William A. Gaines, filed on behalf of PSE.

Parties' Positions

PSE argues that PSE's stricken testimony concerned BPA's current rate case, not BPA's 1996 rate case; that the statements were not hearsay because they were admissions of a party opponent; and that even if PSE's statements were hearsay, BPA should admit the statements anyway. *See* PSE Motion to Reverse Hearing Examiner's Order Striking Testimony, WP-02-M-53, at 2-6 ("PSE Motion"); PSE Ex. Brief, WP-02-R-PS-01, at 1-8.

BPA's Position

BPA moved to strike a limited portion of PSE's testimony on two grounds: (1) the testimony was not relevant and, even if relevant, its prejudicial effect far outweighed its probative value; and (2) the testimony constituted inadmissible hearsay. *See* BPA's Motion to Strike Direct Testimony of PSE, WP-02-M-15 ("BPA Motion").

Evaluation of Positions

In its motion, filed November 22, 1999, BPA argued that PSE's testimony should be stricken on two grounds: (1) the testimony is not relevant and, even if relevant, its prejudicial effect far outweighs its probative value; and (2) the testimony constitutes inadmissible hearsay. *Id.* PSE filed a response to BPA's motion. *See* PSE's Answer in Opposition to BPA's Motion to Strike Direct Testimony of PSE, WP-02-M-19. In its answer, PSE argued that its testimony was relevant, not unfairly prejudicial, and not inadmissible hearsay. *Id.* On December 8, 1999, the Hearing Officer issued an order striking PSE's testimony. *See* Order Granting In Part And Denying In Part Motions To Strike Testimony, WP-02-O-14, at 1-3 ("Order"). PSE did not file a motion for reconsideration with the Hearing Officer. On February 28, 2000, PSE filed a motion asking the Administrator to reverse the Hearing Officer's order. *See* PSE Motion. In the Draft ROD, BPA upheld the Hearing Officer's order because the Hearing Officer's order was well-reasoned and the facts supporting the order had not changed. Draft ROD, WP-02-A-01, at 18-13 through 18-17.

In its motion and brief on exceptions, PSE quotes its stricken testimony, the review of which again establishes that such testimony is not relevant. PSE Motion at 2-3; PSE Ex. Brief, WP-02-R-PS-01, at 3-4. The quotations in PSE's stricken testimony related solely to BPA's 1996 rate case and not the current rate case. *See* PSE Motion at 2-3. PSE's witness quoted a newspaper article written, not by the witness, but by a reporter for the Oregonian. The article paraphrases and briefly quotes a BPA employee, an employee who had not worked on the section 7(b)(2) rate test in the 1996 rate case and who otherwise had no expertise in section 7(b)(2) matters. Tr. 2173-74. The article maintains that the BPA employee described a meeting during which the BPA employee suggested that if the preference customers' rate cap were exceeded [the section 7(b)(2) rate test triggered], costs would be shifted off the preference customers and aluminum companies. In the article, the employee is quoted as saying that no one at the meeting responded verbally to his statement. While it is beyond dispute that the quoted statements were made solely in reference to BPA's 1996 rate case, PSE argues that the statements provide "background for understanding the current proceedings" and that the Hearing Officer incorrectly concluded that PSE's inadmissible hearsay testimony was a challenge to BPA's 1996 proceeding. PSE Motion at 3; PSE Ex. Brief, WP-02-R-PS-01, at 4. PSE's argument is incorrect and mischaracterizes the Hearing Officer's order. The Hearing Officer stated:

> The 1996 rate case is final and cannot be reopened. Puget responds that the testimony is offered not as a challenge to the 1996 rates but to demonstrate ongoing behavior that affects the proposed rates. The problem with this argument is that Puget does not show a pattern of ongoing behavior. It takes a single

> newspaper article and assumes the conduct has been "historical." A single event does not, in and of itself, establish a pattern of behavior, nor does it create a sufficient nexus to establish relevancy in the current case.
>
> Puget has an opportunity to test the 2002-2006 rates within the parameters of this proceeding. If it can establish its claims of "distortion" of the proposed rates, it must be done on evidence arising from this case, not the 1996 case.

Order, WP-02-O-14, at 2. It is clear that the Hearing Officer did not simply conclude that PSE's testimony was a challenge to BPA's 1996 rates, but rather, expressly recognized PSE's argument that "the testimony is offered not as a challenge to the 1996 rates but to demonstrate on-going behavior that affects the proposed rates." *Id.* The Hearing Officer also directly addressed PSE's argument, finding that PSE's testimony, even if offered to demonstrate ongoing behavior, "does not show a pattern of on-going behavior. It takes a single newspaper article and assumes the conduct has been 'historical.' A single event does not, in and of itself, establish a pattern of behavior, nor does it create a sufficient nexus to establish relevancy in the current case." *Id.* In any event, PSE has not provided a sufficient nexus between the statement and the present rate case to show that it has any relevance to the matters under consideration here.

PSE argues that in BPA's 1996 rate case, BPA made a number of incorrect assumptions and calculations in conducting the 7(b)(2) rate test in order to keep the DSI aluminum companies from leaving BPA. PSE Motion, at 4; PSE Ex. Brief, WP-02-R-PS-01, at 5. These allegations were thoroughly rebutted in BPA's 1996 ROD, WP-96-A-02, at 221-268, and in the current rate case, Kaptur *et al*., WP-02-E-BPA-56, at 2-5. PSE argues that BPA's 1996 rate case decisions took benefits away from residential customers and gave them to DSI companies. PSE Motion, at 4; PSE Ex. Brief, WP-02-R-PS-01, at 5. These allegations also were thoroughly rebutted in BPA's 1996 ROD, WP-96-A-02, at 221-268, and in the current rate case, Kaptur *et al*., WP-02-E-BPA-56, at 2-5. PSE also argues that although circumstances are different, BPA continues to perpetuate its past mistakes. PSE Motion, at 4; PSE Ex. Brief, WP-02-R-PS-01, at 5. This argument lacks merit. In its brief on exceptions, PSE refers in a footnote to BPA's testimony in its 1996 rate case and to the IOUs' testimony in the current case as BPA's alleged "continued mistakes." PSE Ex. Brief, WP-02-R-PS-01, at 5, n. 8. PSE's reference to BPA's 1996 testimony is to an excerpt of a discussion of the DSI margin. This issue is also referenced by PSE in the IOUs' testimony with regard to excluding revenue taxes in calculating the DSI margin. These issues are not decided in conducting the section 7(b)(2) rate test, but are decided in the development of rates for BPA's DSI customers. PSE and the IOUs had the opportunity, and in fact used the opportunity at great length in BPA's current rate case, to file testimony and legal briefs regarding this issue. *See* Hoff *et al*., WP-02-E-AC/GE/IP/MP/PL/PS-03, at 3, 11-12; Hoff *et al*., WP-02-E-AC/GE/IP/MP/PL/PS-10, at 1-3; Hoff *et al*., WP-02-E-AC/GE/IP/MP/PL/PS-13, at 2-3; IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 27-47. Any decision in BPA's current rate case on this issue will be made on the record of BPA's 2002 rate case.

PSE's footnote citation to the IOUs' testimony in the current rate case leads one to a list of issues. PSE Ex. Brief, WP-02-R-PS-01, at 5, n. 8, citing Hoff *et al*., WP-02-E-AC/GE/IP/MP/PL/PS-03, at 6-7. The first of these issues concerns BPA's ASC

Methodology, which was developed in a separate administrative proceeding in 1984 and is not established in BPA's rate cases. This procedural issue is addressed in detail in the current proceeding. *See* ROD section 11.2. Because it is not a substantive rate case issue, it is not a continuing rate case "mistake." Another issue referenced by PSE is BPA's 1996 alleged failure to equalize cash reserve accumulations in the Program Case and 7(b)(2) Case. The IOUs did not raise this issue in BPA's current rate case. Because they have not raised the issue in the current proceeding, and it is not a contested issue, it is inappropriate to refer to it as a continuing mistake. Another issue referenced by PSE is BPA's 1996 alleged failure to limit the cash reserve accumulation. This is a revenue requirement issue and again, the IOUs did not raise this issue in BPA's current rate case. Because they have not raised the issue, and it is not a contested issue, it is inappropriate to refer to it as a continuing mistake. Another issue referenced by PSE is BPA's alleged failure to include the proper amount of section 7(g) costs as uncontrollable events in the 7(b)(2) rate test. This issue is being addressed in BPA's current rate case. The issues regarding uncontrollable events in the current case, however, are *different* issues from those addressed in BPA' 1996 rate case. The current case involves PNRR and the costs of terminated generating facilities, arguments that were not raised by any party in BPA's 1996 rate case. Draft ROD, WP-02-A-01, section 13.3. Therefore, these issues cannot be continuing mistakes, as they are new issues. Another issue identified by PSE is the issue of calculating Mid-C resource availability and costs. This issue did not affect the development of BPA's rates in 1996 in any manner whatsoever, because the circumstances for implementing this issue did not arise. In addition, this issue is moot in the current rate case. Draft ROD, WP-02-A-01, section 13.5. It is inappropriate to refer to this issue as a continuing mistake when it did not affect BPA's 1996 rates and the issue is moot in the current rate case. Another issue referenced by PSE is the inclusion of a 7(b)(2) industrial adjustment in a 7(c)(2) delta calculation. This is a COSA issue and not a section 7(b)(2) rate test issue. *See also* Draft ROD, chapter 13, section 13.5. More importantly, however, the IOUs did not raise this issue in BPA's current rate case. Because they have not raised the issue, and it is not a contested issue, it is inappropriate to refer to it as a continuing mistake.

In summary, PSE's argument that BPA has continued mistakes from its 1996 rate case has little merit, and thus the nexus between the newspaper article and BPA's current rate case is virtually non-existent. Insufficient facts relevant to the current rate case have been introduced to demonstrate any impropriety on BPA's part in the present proceeding. Therefore, no relevance can attach to facts from the 1996 rate case introduced to show a "pattern." *See* Fed. R. Evid. 401, 402, and 403.

PSE also fails to mention that the issue it has raised regards PSE's reliance on a newspaper article as the sole basis for this portion of its testimony. As noted above, the Hearing Officer's order expressly recognized that this newspaper article and a single event do not establish a pattern of behavior or create a sufficient nexus to establish relevancy in the current case. Order, WP-02-O-14, at 2. PSE also fails to note that PSE "has an opportunity to test the 2002-2006 rates within the parameters of this proceeding. If it can establish its claims of 'distortion' of the proposed rates, it must be done on evidence arising from this case, not the 1996 case." *Id.* In fact, PSE was permitted to raise these arguments in testimony that was not stricken. *See* Gaines, WP-02-E-PS-01, at 9-10; Hoff *et al.*, WP-02-E-AC/GE/IP/MP/PL/PS-03, at 7-8; Eakin *et al.*, WP-02-E-02, at 3. PSE has therefore not been precluded from raising this issue in the rate case; rather, it has been required to do so with relevant evidence.

PSE next argues that the excluded statements were not hearsay because they were admissions of a party opponent. PSE Motion, at 4; PSE Ex. Brief, WP-02-R-PS-01, at 7. It should be noted at the outset that hearsay evidence is generally admissible at an administrative hearing. Stein *et al*., Administrative Law at §26.01. However, its status as hearsay is germane to the question of whether or not the evidence is relevant and, just as important, to the question of how much weight the evidence should be given, in the event that it were admitted into the record. *Id*. at §26.02. This issue was directly addressed in BPA's motion to strike and in the Hearing Officer's order. BPA's motion to strike noted:

> Rule 801 of the Federal Rules of Evidence defines hearsay as "a statement, other than one made by the declarant while testifying at the trial or hearing, offered in evidence to prove the truth of the matter asserted." The testimony BPA moves to strike is inadmissible hearsay. Indeed, PSE's testimony is triple hearsay. PSE quotes a newspaper article, which in turn quotes alleged statements made by a BPA employee, whose impressions are, in turn, predicated on his conclusion that non-verbal conduct of other persons was intended as an affirmation of his own statements. The Hearing Officer has recognized that this type of testimony is inadmissible. In BPA Docket No. FPS-96R, 1996 Firm Power Products and Services Rate Schedule Correction Proceeding, the Hearing Officer excluded testimony that quoted a regional newsletter, which in turn quoted a BPA employee. The facts in the instant case are virtually identical and PSE's hearsay testimony should be excluded for the same reasons. See Order Granting In Part And Denying In Part Motion To Strike Testimony, FPS-96R-O-08 at 3.

While PSE may argue that the triple hearsay in its testimony is an admission of a party-opponent, this argument is not persuasive. In *Horta v. Sullivan*, 4 F.3d 2 (1st Cir. 1993), a newspaper article bearing a striking factual similarity to the one in question here was stricken. The plaintiff attempted to introduce a newspaper account reporting statements of one of the defendants which contradicted an affidavit submitted in support of the motion for summary judgment. *Id.* at 8. On appeal, the court ruled that the article should have been stricken and could not be used to show there was a genuine issue of material fact:

> The account is hearsay, inadmissible at trial to establish the truth of the reported facts. In fact, the newspaper account is hearsay within hearsay. *See* Fed. R. Evid. 805. Even were appellee Chief Mello the sole source of the article's information, so that his statements could be regarded as the nonhearsay admissions of a party opponent, *see* Fed. R. Evid. 801(d)(2), the article itself constitutes inadmissible out-of-court statements, by unidentified persons, offered to prove the truth of the matter asserted. *See* Fed. R. Evid. 801(c).

Id. Similarly, PSE offers a newspaper article that sparingly quotes a BPA employee's statements. These statements leap to an inference of bad motive based only on a temporal sequence of events that involved no oral or written assertions whatsoever. BPA has no opportunity to test the credibility of the reporter or the accuracy of his perceptions. Moreover, there is no indication that the non-verbal conduct upon which the BPA employee based his conclusions was in any way intended to constitute consent or acquiescence to his statement. BPA Motion at 5-6. BPA also noted that:

> As the courts have recognized, "[t]hat a statement of fact appears in a daily newspaper does not of itself establish that the stated fact is 'capable of accurate and ready determination by resort to sources whose accuracy cannot reasonably be questioned.'" *Cofield v. Alabama Public Service Commission*, 936 F.2d 512 (11th Cir. 1991).

Id. at 6. More importantly, the Hearing Officer concluded that PSE's argument was not persuasive:

> Puget makes additional arguments concerning unfair prejudice and admissions that are not inadmissible hearsay. Puget claims the hearsay testimony must be allowed because it cannot compel the appearance of the reporter or of Mr. Revitch who was quoted in the news article. This does not help Puget's case because it does not have the right witness to authenticate the newspaper article or to prove the truth of the contents . . . Puget's witness was not involved in the creation of the news release and cannot testify as to whether the article accurately repeats statements made by Mr. Revitch or whether the statements were taken out of context for some other purpose.
>
> A newspaper article, presented for the truth of the facts contained therein, without substantiation, has no foundation and no probative value whatsoever. Because of this, any evidentiary value is substantially outweighed by the danger of unfair prejudice. Rule 403, Federal Rules of Evidence.

Order at 3. As noted by the Hearing Officer, PSE could not provide a witness to authenticate the newspaper article in any manner. *Id*. In this instance, PSE's witness did not testify to having any personal knowledge regarding the Oregonian reporter who attributed certain remarks to a BPA employee, Mr. Revitch, or any personal knowledge regarding the reporter's development of the newspaper article. In addition, PSE's witness did not profess to have any connection with Mr. Revitch's statements to the Oregonian reporter, particularly with respect to how Mr. Revitch interpreted a BPA officer's non-verbal conduct. Furthermore, PSE's witness did not claim to have any personal knowledge regarding the non-verbal conduct attributed to the other BPA employee who, by his silence, allegedly acted upon Mr. Revitch's statements. While it is true that hearsay evidence may be admissible in an administrative proceeding, common sense dictates that it should have some reasonable basis. In this situation, where PSE's witness is three steps removed from the original declarant and can offer no independent basis for the reliability of the statement, the testimony is not proper.

PSE also argues that while Mr. Revitch was a witness in BPA's 1996 rate case, he was not a witness in BPA's current rate case, and therefore PSE was prevented from cross-examining him. PSE Motion, at 5; PSE Ex. Brief, WP-02-R-PS-01, at 7. The reason Mr. Revitch was not a witness in BPA's current rate case is because he had not worked on the current rate case or any other rate development for some years. Indeed, Mr. Revitch was not performing *any* work regarding BPA's rate development at the time of his alleged statements, so the alleged statements were not a matter within the scope of Mr. Revitch's employment at that time. Mr. Revitch is employed in the Corporate Division of BPA as a computer specialist. Mr. Revitch's change of position does not excuse PSE's failure to provide a witness to authenticate the newspaper article or to prove the truth of its contents. PSE also argues that if the newspaper misquoted Mr. Revitch, BPA could have called Mr. Revitch as a rebuttal witness to explain or refute his statements in the article. PSE Ex. Brief, WP-02-R-PS-01, at 6. This argument begs the question of whether the evidence is relevant and therefore admissible. As noted at great length above, such evidence is not relevant.

Finally, PSE argues that even if the statements were hearsay, they should be admitted in the interests of justice. PSE Motion, at 5; PSE Ex. Brief, WP-02-R-PS-01, at 7-8. PSE first attempted to support this argument by citing a series of questions and answers that only established that a newspaper article was written about BPA's 1996 rate case and a person named Mr. Revitch once worked for Mr. Keep. PSE Motion, at 5. This does not overcome all of the foregoing shortcomings of PSE's testimony. PSE also argues that when a statement is material, probative, and the interests of justice are served by admission, a court has the discretion to admit such a statement into evidence. PSE cites Fed. R. Evid. 807, which provides:

> A statement not specifically covered by Rule 803 or 804 but having equivalent circumstantial guarantees of trustworthiness, is not excluded by the hearsay rule, if the court determines that (1) the statement is offered as evidence of a material fact; (2) the statement is more probative on the point for which it is offered than any other evidence which the proponent can procure through reasonable efforts; and (3) the general purposes of these rules and the interests of justice will be served by the admission of the statement into evidence. However, a statement may not be admitted under this exception unless the proponent of it makes known to the adverse party sufficiently in advance of the trial or hearing to provide the adverse party with a fair opportunity to meet it, the proponent's intention to offer the statement and the particulars of it, including the name and address of the declarant.

First, it must be noted that the alleged statement is *not* more probative on the point for which it is offered than any other evidence which the proponent could have procured through reasonable efforts. There is no evidence that PSE ever asked the reporter or the BPA employee to appear as a witness at the hearing. Such requests could have been made through reasonable efforts. Such testimony would have been more probative than PSE's reliance on a witness relying on a newspaper article relying on statements by another person in the article relying in turn upon non-verbal actions of another party. In addition, the general purposes of these rules and the interests of justice will not be served by the admission of the statement into evidence given the nature of the statement as described previously. Finally, Fed. R. Evid. 807 states that "a statement may not be admitted under this exception unless the proponent of it makes known to the adverse party sufficiently *in advance of the trial or hearing* to provide the adverse party with a fair opportunity to meet it, the proponent's intention to offer the statement and the particulars of it, including the name and address of the declarant." (Emphasis added.) In this instance, PSE did not make its intended testimony known to BPA, the adverse party, sufficiently in advance of the hearing to provide BPA a fair opportunity to meet it. Indeed, PSE did not provide the statement to BPA in advance of the hearing *at all*. The hearing began on August 24, 1999, and PSE did not make the statement available to BPA until PSE filed testimony on November 2, 1999. Consequently, in addition to PSE's failure to provide the statement to BPA before the hearing, PSE did not provide BPA with PSE's intention regarding the statement, the particulars of the statement, or the name and address of the declarant. Clearly, PSE has not satisfied the standards for application of Fed. R. Evid. 807. In summary, PSE's testimony is inadmissible for the foregoing reasons, and the Hearing Officer's order should not be reversed. To the extent that the Hearing Officer may have been in error, the probative value of the article is so tenuous that it would not be entitled to significant weight even if it were admitted.

Decision

PSE's motion to reverse the Hearing Officer's order striking PSE's testimony is denied. The Hearing Officer's order is well-reasoned, and the facts supporting the order have not changed. PSE's additional arguments are not persuasive for the reasons noted above.

18.2 Procedural Due Process

18.2.1 Subscription Strategy Record of Decision

Issue

Whether the Subscription Strategy public process should be "recommenced in a way that allows discovery and evidence on any and every issue decided in the Subscription ROD" and correspondingly, whether every decision made in the Subscription ROD should "be declared non-final and open for decision in the newly commenced proceeding." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 18.

Parties' Positions

Alcoa/Vanalco contend that "the Subscription ROD announced decisions on many items that should be decided in a section 7(i) rate case." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 17; Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-02, at 111. Alcoa/Vanalco further argue that although BPA took the position that matters decided in the Subscription ROD were impermissible subjects for the rate case, BPA also took the position that most of the issues decided in the Subscription ROD are not final. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 17. According to Alcoa/Vanalco, "BPA created a situation whereby it made decisions in the Subscription ROD outside the 7(i) process, reversed field to say it would amend those decisions, obtained dismissal of court challenges to its practice on the ground it had not taken final action, yet throughout has forbidden any testimony on those decisions." *Id*. at 18. As a result, Alcoa/Vanalco argue, the Subscription Strategy public process must be recommenced to allow for discovery and evidence on every matter decided in the Subscription ROD, and the ROD must be declared nonfinal.

Alcoa and Vanalco were the only parties to raise this issue.

BPA's Position

In response to allegations by witnesses for Alcoa/Vanalco, BPA witnesses addressed a number of issues in rebuttal testimony regarding the scope of the rate case and BPA's Power Subscription Strategy. Burns and Elizalde, WP-02-E-BPA-37, at 12–19. However, BPA did not take a specific position on whether to "recommence" the Subscription Strategy public process, because determinations made in the Subscription Strategy ROD and public process were expressly excluded from reconsideration in the rate case.

Evaluation of Positions

The arguments raised by Alcoa/Vanalco, as well as the relief requested, relate solely to the Subscription Strategy ROD and public process. This rate proceeding is not the proper forum for BPA to provide such relief, especially given the fact that BPA expressly stated that determinations made in the Subscription Strategy ROD would not be revisited in the instant section 7(i) process.

It is clear that the Subscription Strategy ROD provides important background and context for the rate proceeding. It is equally clear, however, that the Subscription Strategy and the Subscription Strategy ROD did not establish any rates. As emphasized in the Subscription Strategy ROD:

> BPA's Subscription Strategy does not establish any rates or rate designs. The establishment of rates and use of rate design can be determined only in a formal hearing under section 7(i) of the Northwest Power Act. The comments and questions referenced above will be addressed in BPA's power rate development process, which includes extensive opportunities for public involvement. While final rate design decisions are not being made in the Subscription Strategy, rate design approaches identified in the Subscription Strategy will be part of BPA's initial power rate proposal, which is expected to be published early in 1999.

Subscription ROD, at 115, WP-02-E-AL-01, at 122; *see also* Burns and Elizalde, WP-02-E-BPA-37, at 15 (quoting same passage).

As such, Alcoa's and Vanalco's arguments have no merit. Although BPA may have made decisions in the Subscription ROD that were "outside the 7(i) process," those decisions were not rate decisions and therefore a section 7(i) process was neither necessary nor appropriate. Moreover, unsupported assertions that BPA took one position then "reversed field" to take a different position is of no avail. BPA "obtained dismissal of court challenges" primarily because the relief requested by Alcoa and Vanalco was to immediately enjoin the rate case, which was an ongoing administrative proceeding. Consistent with well-established principles of administrative law, and following extensive briefing, the Ninth Circuit rejected Alcoa's and Vanalco's arguments and correctly ruled that it lacked jurisdiction over their claims. *Alcoa et al. v. Bonneville Power Administration,* Nos. 99-71188 & 99-71189; *Goldendale Aluminum Co., et al. v. Bonneville Power Administration,* Nos. 99-70268 *et seq.*

If Alcoa and Vanalco believe there was some infirmity related to the Subscription Strategy ROD and public process, then it was incumbent upon Alcoa and Vanalco to raise their concerns in that forum. *See, generally, Vermont Yankee Nuclear Power Co. v. NRDC*, 435 U.S. 519, 553-54 (1978). As participants in the Subscription Strategy public process, Alcoa and Vanalco had every opportunity to present their views and concerns in that proceeding. The Subscription Strategy ROD was issued in December 1998, more than 16 months ago. There is no basis for Alcoa and Vanalco to collaterally attack in the instant rate proceeding the Subscription Strategy ROD long after it was issued.

Decision

BPA will not recommence the Subscription Strategy public process as requested by Alcoa/Vanalco.

18.2.2 Fish and Wildlife Issues

Issue 1

Whether BPA properly excluded from the section 7(i) process testimony and argument on the 13 Fish and Wildlife Alternatives, the equal weighting of those 13 Alternatives, and the range of fish and wildlife costs adopted in the Principles.

Parties' Positions

The IOUs allege that "BPA has arbitrarily assumed that the 13 fish and wildlife scenarios are equally likely to occur." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 91. The IOUs argue that "the Administrator has prohibited parties from offering evidence on the assumption that all 13 of the Fish and Wildlife Alternatives are equally likely to occur. BPA has arbitrarily concluded that each of the alternatives has an equal probability of occurring. BPA will not allow inquiry on whether this assumption is justified. By this unrealistic assumption BPA precludes an inquiry into the costs of the most probable outcome." *Id*. *See also*, IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 72-73.

BPA's Position

BPA is implementing the Principles in the 2002 rates. DeWolf *et al.*, WP-02-E-BPA-13, at 7. The Principles were adopted in the fall of 1998 after extensive regional discussion and coordination with concerned executive branch agencies. *Id*. The Principles were published on September 16, 1998, and Vice President Gore announced the establishment of the Principles on September 21, 1998. DeWolf *et al.*, WP-02-E-BPA-39, at 21-22. The 13 Fish and Wildlife Alternatives represent, in the Clinton Administration's judgment and based on extensive regional input, a reasonable range within which the costs of eventual decisions on system reconfiguration and related operations can be expected to fall. DeWolf *et al.*, WP-02-E-BPA-13, at 9. It was well understood at the time the Principles were adopted that cost estimates would continue to evolve as the analysis, planning, and decision process for system reconfiguration and related actions progressed. *Id.* at 10. But the range of costs established by these 13 Fish and Wildlife

Alternatives is deemed by the Executive Branch to be sufficiently high and broad for BPA ratesetting and Subscription purposes. *Id.*

The Principles recognize that BPA is setting wholesale power rates and initiating Subscription before decisions on system reconfiguration and other fish and wildlife recovery actions are made. DeWolf *et al*., WP-02-E-BPA-13, at 9. For this reason, the Principles are intended to "keep the options open" for future decisions by: (1) specifying that each of the 13 Fish and Wildlife Alternatives should be treated by BPA as equally likely to occur; and (2) establishing a high cost-recovery goal, expressed as an 88 percent/five-year TPP goal. *Id.* Thus, the 13 Fish and Wildlife Alternatives represent a set of assumptions, a forecasting convention, to establish capital investment and O&M levels, system operations assumptions, and risk analysis assumptions for purposes of setting rates. *Id.* It would be impractical and serve no policy purpose for BPA to resurrect and explore once again the myriad issues that have already been fully aired and addressed in these other public review processes. DeWolf *et al*., WP-02-E-BPA-39, at 25.

Evaluation of Positions

The IOUs state that "[t]he assumptions regarding BPA's future fish and wildlife costs have a significant effect on BPA's revenue requirement in this proceeding. The range of assumed annual costs of the 13 alternatives is from $100 million to $179 million." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 91.

The IOUs state that "[m]ost of the alternatives involved the breaching or removal of dams," and argue that "[b]y assuring that dam breaching was as likely as not, BPA assumed a huge cost impact." *Id*.

The IOUs allege that "[b]y making an arbitrary assumption that all 13 alternatives are equally likely, BPA has prevented its customers from being able to adequately address estimates [sic] BPA's fish and wildlife costs and BPA's assumptions about the uncertainties surrounding these costs." *Id.* at 93.

As discussed in more detail in ROD section 2.3, *supra*, the Principles were developed in an extensive public involvement process that included numerous Federal agencies (including the NMFS, USFWS, Reclamation, COE, and EPA), state agencies, the Northwest Congressional delegation, Columbia Basin Tribes, public interest groups, BPA customers, and interested members of the public. 64 Fed. Reg. 44318, 44321 (1999).

It was clearly understood at the outset of the Fish and Wildlife public involvement process that the results from this process would guide BPA's ratemaking process. The public involvement process focused on providing guidelines for structuring BPA's approach to Subscription in order to ensure that BPA could meet its financial obligations, including those for fish and wildlife. DeWolf *et al*., WP-02-E-BPA-39, at 21. Of necessity, BPA must move forward in setting rates for the post-2001 rate period, in large part because it must negotiate new power sales contracts for the post-2001 rate period. *Id.* at 22-23. The Principles recognized the impossibility of accomplishing either of these tasks if uncertainties about fish and wildlife funding costs remained. *Id*. at 23. For this reason, a range of alternatives and associated costs is specified in the Principles. *Id*.

The IOUs contend that BPA made an "arbitrary assumption that all 13 alternatives are equally likely," thereby preventing BPA's customers from being able to adequately address estimates of BPA's fish and wildlife costs and BPA's assumptions about the uncertainties surrounding these costs. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 93. To the contrary, the fact that there is still no consensus on a fish and wildlife recovery strategy reinforces the need to "keep the options open." Equal weighting is a reasonable strategy for addressing this uncertainty. Through such a strategy, BPA can address the broad range of potential costs for fish and wildlife recovery during the FY 2002-2006 rate period. As stated in the Federal Register notice:

> In the absence of a consensus on a post-2001 fish and wildlife recovery strategy by mid-1998, concerned Federal agencies and regional stakeholders agreed that a strategy and mechanism were needed to establish post-2001 fish and wildlife funding assumptions for Subscription and ratemaking purposes. This strategy is directed at "keeping the options open" for future decisions on long-term configuration of the FCRPS, including the potential drawdown of reservoirs behind the four Lower Snake River projects and John Day Dam on the mainstem of the Columbia. Without such a strategy and mechanism, BPA could not proceed with its Subscription process for post-2001 power sales or its FY 2002-2006 power rates process because BPA could not provide the necessary cost certainty to its potential post-2001 power sales customers, nor assure adequate funding for fish and wildlife recovery efforts.

64 Fed. Reg. 44318, at 44321 (1999).

It was reasonable and prudent for BPA to implement the Principles' strategy of "keeping the options open." To do otherwise would have arbitrarily foreclosed potential fish and wildlife recovery options.

The Principles that were developed as a result of the extensive fish and wildlife public involvement process addressed several issues. As a result, the Federal Register Notice appropriately identified those policy decisions, commitments, and assumptions that would not be at issue in this power rate proceeding:

> Included among the policy decisions, commitments, and assumptions that are not at issue in this rate proceeding are: (1) The Administration's decision to extend the existing terms of access to the FCCF and to roll over the existing formula for calculating section 4(h)(10)(C) credits from the current rate period to FY 2006; (2) the content, merits, or level of costs for the fish and wildlife recovery strategies reflected in each of the 13 alternatives; (3) the decision to include the full range of costs for all 13 alternatives for the purposes of BPA's repayment study, revenue requirement, revenue forecast, and risk management studies and strategies; (4) the TPP goal of 88 percent over the five-year rate period with a "floor" of 80 percent; (5) the policy objective that rates and contracts be designed to position BPA to achieve similarly high TPP post-2006; (6) the incorporation of the full range of costs using the same probabilistic method BPA uses for other

> cost and revenue uncertainties in its ratemaking; (7) the assumption that all 13 alternatives are equally likely to occur; (8) the assumption that BPA's annual fish and wildlife operations and maintenance costs have an equal probability of falling anywhere within the range of $100 million and $179 million; (9) the adoption of a flexible approach in order to respond to a variety of different fish and wildlife cost scenarios, and in particular, the 35 to 45 percent goal of total post-2001 sales in contract-term lengths of three years or less, in short-term surplus sales, and/or in cost-based indexed sales; and (10) the goals of adopting rates and contract strategies that are easy to implement and administer.

64 Fed. Reg. 44318, at 44322-23 (1999).

It would be impractical and serve no policy purpose for BPA to resurrect and explore once again the myriad issues that have already been fully aired and addressed in the fish and wildlife public involvement process. *Id.* at 25.

On the other hand, the Federal Register Notice also described several issues that were not addressed in the Principles and that would be addressed in the rate proceeding:

> Fish and wildlife issues that will be addressed in this rate proceeding include: (1) how the terms of access to the FCCF are modeled in the rate proposal and their impact on TPP and rates; (2) how section 4(h)(10)(C) credits are modeled in the rate proposal and their impact on TPP and rates; (3) the calculation and treatment of operations and maintenance and capital investment in repayment studies and the revenue requirement; (4) the selection, design, terms and conditions, assumptions, treatment, and impact of planned net revenues for risk, CRAC, indexed power sales contracts, stepped rates, and targeted adjustment charge; (5) the RiskMod, NORM, and Tool Kit model design, operation, inputs and outputs, and use of results; (6) the level of TPP that is targeted, from the range of potential TPP targets established in the Principles; and (7) the design, terms and conditions, assumptions, and treatment of the DDC, including the threshold for triggering a dividend distribution, the conditions under which a dividend is distributed, and the mechanism used to distribute dividends to certain power customers.

64 Fed. Reg. 44318, at 44322 (1999).

To subject the Principles to an evidentiary hearing in a BPA rate proceeding would not only serve no useful purpose, but would undermine the integrity of the prior public process that fully afforded all interested parties ample opportunity to provide comments.

Decision

BPA properly excluded from the section 7(i) process testimony and argument on the 13 Fish and Wildlife Alternatives, the equal weighting of those 13 Alternatives, and the range of fish and wildlife costs adopted in the Principles. It was reasonable and prudent for BPA to implement the

Principles' strategy of "keeping the options open." It would also be impractical and serve no policy purpose for BPA to resurrect and explore once again the myriad issues that have already been fully aired and addressed in the fish and wildlife public involvement process.

Issue 2

Whether BPA provided the parties with an opportunity to fully and fairly examine all fish and wildlife issues that should be examined in ratesetting, thus allowing the development of a full and complete record in this section 7(i) proceeding.

Parties' Positions

The IOUs state that "[t]he Federal Register Notice for this proceeding . . . identified several areas that the [BPA] Administrator has designated as off-limits in this rate proceeding." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 90. The IOUs argue that "[b]y declaring so many subjects out-of-bounds (including particularly the estimates of future risks and cost levels), we believe the Administrator has precluded BPA and its customers from fully and fairly examining the issues that should be examined in setting rates and prevented the development of a full and complete record in this proceeding in violation of sections 7(i)(2) and (3) of the Northwest Power Act." *Id*.

In its brief on exceptions, the IOUs object to BPA's exclusion of the 13 Fish and Wildlife Alternatives from the 7(i) process. The IOUs state that the Draft ROD purports to decide that equal weighting is necessary to "keep the options open," but the IOUs argue that this is a rate case decision on an issue excluded by BPA from the rate case. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 72-73.

CRITFC/Yakama also argue in their brief on exceptions that BPA then "limited the discussion in the FRN scope of the rate case and proudly states they are following the FRN." *Id.* They go on to say that "CR/YA has been nothing but consistent throughout the discussions in the development of the Principles and in the rate case and Bonneville has ignored or refused pertinent information at every stage of the process. This is arbitrary and capricious." *Id*.

ICNU alleges that "BPA is circumventing its statutorily required ratemaking procedures by establishing rates outside of this rate case." ICNU Brief, WP-02-B-IN-02, at 2.

The PPC claims that "[b]y prohibiting relevant information concerning fish and wildlife from entering the rate case record, BPA has effectively steered the rate case away from information that could have an impact on the development of a full and complete justification of the final rates by the Administrator. This violates both the spirit and the letter of the Northwest Power Act." PPC Brief, WP-02-B-PP-01, at 46-47.

The PPC also argues that "BPA's preemptive actions essentially impair the rights of BPA's customers to present the information necessary to justify lower or revised rates. This in turn is in violation of the Due Process Clause of the Fifth Amendment to the U.S. Constitution . . . ." *Id*. at 47; *see also* PPC Ex. Brief, WP-02-R-PP-01, at 10.

In its brief on exceptions, PPC argues that "[m]aterial and argument on the strategy and Principles are directly relevant to the development of a full and complete justification of the final rates. It is essential to allow parties to present testimony regarding the validity of the strategy and Principles to test their impact on the proposed rates." PPC Ex. Brief, WP-02-R-PP-01, at 9.

Alcoa/Vanalco and Energy Services alleged that "BPA is attempting to limit the scope of this rate case and to exclude testimony from the record that could be used to support rate decisions significantly different than BPA's initial rate proposal." Speer *et al*., WP-02-E-AL/VN/EG-02, at 3. Alcoa/Vanalco and Energy Services argued that "[t]here are so few remaining issues to be decided within the formal rate process that it makes a mockery of the process Congress provided for setting BPA's cost-based rates." *Id*. at 9. Alcoa/Vanalco argue that "[f]ish and wildlife costs are properly rate case issues, and the rate case record must be reopened to allow BPA to provide its justification, if any, for base costs, and to allow all parties to submit testimony and cross-examination." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 22.

Alcoa/Vanalco argue in their brief on exceptions that "BPA forbade any evidence on the 13 Fish and Wildlife Alternatives, the equal weighting of those Alternatives, and the range of fish and wildlife costs adopted in the Principles . . . [B]y excluding evidence referred to above, BPA prevents a major issue from being decided in the rate case, in violation of Due Process, the Administrative Procedures Act, §7(i), and law forbidding the Administrator to act on issues with a closed mind." Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 112.

BPA's Position

In the Federal Register Notice announcing the power rate proceeding, BPA described with particularity the nature and scope of the proceeding. 64 Fed. Reg. 44318 (1999). BPA explained that four major public involvement and review processes had been undertaken by BPA in the past five years, and that the rate case would implement policy decisions reached in those processes. *Id*. at 44319-23. The four major public processes referred to are the Business Plan public process, the Cost Review process, the Subscription Strategy process, and the Principles process. *Id*. BPA stated that it would not revisit in the rate case any policy determinations previously made in any of these forums. *Id*.

In the case of the Principles, BPA directed the Hearing Officer to exclude material which attempts to revisit the policy merits or wisdom of the Principles or of the strategy to "keep the options open." 64 Fed. Reg. 44318, 44322. In general, BPA's approach during the rate proceeding was to incorporate the results of these processes, as appropriate, into the rate proceeding and provide an opportunity for the parties to test the impact of those policy determinations on BPA's rates.

Policy level determinations and program levels are not properly the subject of a section 7(i) hearing. Section 7(i) of the Northwest Power Act is applicable to the establishment of rates only, not broad policy or program level determinations such as program goals and objectives, processes, priorities, and allocation of resources that may impact rates. The Principles do not establish monetary charges for the sale of electric power. Rather, they are a set of principles intended to "keep the options open" for future fish and wildlife decisions. These are strictly policy and program level determinations. Further, a section 7(i) rate process is not the appropriate forum for debating either the policy reasons for, or biological merits of, potential strategies for fish and wildlife recovery.

In addition, the Principles were not developed by BPA alone. Rather, they were developed in a public process that included virtually all stakeholders throughout the region, and the Principles were ultimately endorsed and announced by Vice President Gore. Nothing in the Northwest Power Act requires BPA to subject these Principles to an evidentiary hearing in a BPA rate proceeding. Moreover, to do so would not only serve no useful program or policy purpose, but would undermine the integrity of the public process that led to the Principles.

Evaluation of Positions

The IOUs argue that "BPA's exclusion of testimony and cross-examination of the assumptions underlying the revenue requirement (such as the assumptions regarding the 13 Fish and Wildlife Alternatives) exceeds the discretion of the Administrator and is contrary to the provisions of Section 7 of the Northwest Power Act." IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 93.

The IOUs argue that "[a] full and complete record . . . cannot be developed if the Administrator has removed certain issues from the parties' review and the parties are not allowed to present testimony or briefs on these issues, or cross examine BPA's witnesses." *Id*.

ICNU argues that "BPA has excluded consideration of all operating costs, including fish and wildlife obligations." ICNU Brief, WP-02-B-IN-02, at 3. Therefore, ICNU alleges that "as a result of the exclusion of certain significant costs from consideration in this case, any rates approved by the Administrator will be set contrary to the ratemaking procedures required by law." *Id.*

Alcoa/Vanalco argue that "BPA unlawfully delegated rate-making decisions to the Administration of President Clinton, and more specifically, Vice President Gore . . . ." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 18. Alcoa/Vanalco state that "Congress directed that these decisions should be made by the BPA Administrator, not the Administration." *Id*. Alcoa/Vanalco allege that "BPA erred in adopting this rate decision by the Administration because Congress intended BPA to make this decision based on is [sic] independent judgment in the § 7(i) rate process." *Id*.

Alcoa/Vanalco argue in their brief on exceptions that:

> BPA first excluded all evidence from the rate case regarding the 13 Fish and Wildlife Alternatives and then stated that "there is no consensus regarding which alternative should be implemented, or even which alternative is most likely to result in better salmon recovery" to support its equal weighting on the 13 Alternatives. (DeWolf *et al*., WP-02-E-BPA-39, at 28.) BPA cannot have it both ways. BPA has extended the "keep the options open" policy to such an extent that decisions that must be made during the rate case now cannot be made until some indefinite period in the future, long after the Administrator must issue

> her rate case ROD. In short, BPA is refusing to do exactly what Congress intended it to do; predict its future costs and then set rates to meet those costs. That is an abuse of discretion in violation of the Administrative Procedures Act, the Due Process clause, and the Northwest Power Act, especially §7(i).

Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 17.

Alcoa/Vanalco is mistaken about the timeline surrounding the development of the Principles (and the 13 Fish and Wildlife Alternatives) and the Federal Register Notice initiating this power rates proceeding. The Principles were developed *prior* to the initiation of these power rate proceedings, not *after* the Federal Register Notice was published. The Principles were developed specifically because the region could not reach consensus on a fish and wildlife recovery strategy post-2001. It was only subsequent to the establishment of the Principles that BPA initiated this rate proceeding. BPA did not first exclude all evidence regarding the 13 Fish and Wildlife Alternative, thus chilling any further debate, as alleged by Alcoa/Vanalco. BPA fails to see how BPA testimony acknowledging the lack of consensus in the region surrounding a fish and wildlife recovery strategy in any way translates into a refusal by BPA to predict its future costs and set rates. To the contrary, there is ample evidence on the record to support BPA's efforts to accommodate the uncertainty surrounding this lack of regional consensus on a fish and wildlife recovery strategy and BPA's efforts to address this uncertainty in its risk mitigation package.

Alcoa/Vanalco state that "[i]n the 1983 rate case and ROD, fish and wildlife program costs were addressed as revenue requirement issues," and "[i]n the 1985 rate case, BPA again addressed fish and wildlife program levels as a revenue requirement issue." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 19. Alcoa/Vanalco state that "[t]he issue was squarely raised [in the 1985 ROD] whether the §7(i) rate process was the appropriate forum to address BPA's decision to fund specific fish and wildlife projects and BPA's estimate of the costs of implementing such decisions." *Id*. at 19-20. According to Alcoa/Vanalco, "[t]he Administrator found that the decisions to fund specific projects are not an issue in the rate filing, but that projected fish and wildlife costs must be included in the rate case to substantiate BPA's revenue requirement. Specifically, the 'actual dollars included in BPA's revenue requirements [for fish and wildlife programs] remain proper subjects of testimony and cross-examination in the rate filing. BPA is not required to address program decisions in the rate filing.'" *Id*. at 20.

Alcoa/Vanalco state that "[t]he parties cannot use the § 7(i) process to 'ferret out unjustified or inadequately supported' [quoting from the legislative history of the Northwest Power Act] rate increases if program costs are not subject to rate case testimony and cross-examination." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 20.

Alcoa/Vanalco state that the Administrator's 1983 and 1985 decisions apply to the present case. Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 20; *see also* Alcoa/Vanalco Ex. Brief, WP-02-R-AL/VN-01, at 112-13. Alcoa/Vanalco argue that "[t]he fish and wildlife costs are not based on any specific program decisions because there has [sic] been no fish program decisions for the 2002-06 period. Those costs are just an estimate of the 'actual dollars (that BPA proposes) to be included in revenue requirement' and thus, are properly rate case issues." *Id*. at 20-21.

Alcoa/Vanalco state that in the 1993 rate case, "BPA staff argued that pursuant to §11(b) of the Transmission System Act, BPA was authorized to set program levels subject only to Congress' directive in the budget process, and that public forums other than the §7(i) rate case were more appropriate forums for deciding program levels. The Administrator agreed, but without discussion of the prior specific interpretation of the Act [in the 1983 and 1985 rate cases] with regard to fish costs." Alcoa/Vanalco Brief, WP-02-B-AL/VN-01, at 21. Alcoa/Vanalco argue that the Administrator's reliance on section 11(b) of the Transmission Act is without merit, and that "[t]he suggestion that Congress by deciding spending levels in Transmission Act §11(b) – thereby precludes a determination in the §7(i) process [sic] estimates of spending levels is wrong." *Id*.

<u>Section 7(i) of the Northwest Power Act Governs Development of Rates, Not Policy Decisions or Program Levels.</u>

Section 7(i) of the Northwest Power Act governs BPA's rates. Section 7(a)(1) requires the Administrator to establish rates "to recover . . . the costs associated with the acquisition, conservation and transmission of electric power." 16 U.S.C. §839e(a)(1). Section 7(i)(2) provides that the hearing officer in the rate case shall "develop a full and complete record and . . . receive public comment . . . related to [the] proposed rates." 16 U.S.C. §839e(i)(2). Section 7(i)(5) requires the Administrator to issue a decision establishing rates which shall be "based on the record . . . [and] shall include a full and complete justification of the final rates." 16 U.S.C. §839e(i)(5).

Section 7(i) is a procedural statute. It begins by providing that "[i]n establishing rates under this section, the Administrator shall use the following procedures . . . . "Its purpose is to "set[] . . . forth detailed procedures BPA must follow in establishing rates." H.R. Rep. 976, Part II, 96th Cong., 2d Sess. 53 (1980).

Nothing in the Northwest Power Act or its legislative history states that the procedural requirements of section 7(i) apply to policy decisions or the establishment of program levels. The argument that such program levels are subject to a section 7(i) hearing appears to be derived from a belief that the requirement to develop a "full and complete record" justifies this process. However, the obligation to develop a "full and complete record" does not mean that program levels or policy decisions are "rates" under section 7(i). These are two different issues. The rate case record can be "full and complete" by incorporating the results of earlier processes into the rate proceeding, and relying on the results from those earlier processes to form the background or context for the actual rate proposal. Otherwise, the earlier processes run the risk of becoming futile exercises.

If section 7(i) allows the parties to litigate the structure and content of BPA's program levels and policy decisions, then the rate case becomes a forum not just for establishing BPA's rates, but for deciding how the agency and other entities of the FCRPS will conduct their business. Moreover, if, as in the instant case, specific program levels were established following an extensive public involvement process, then the section 7(i) process is either redundant of the earlier process, or is converted into a forum to reconsider or nullify determinations made in the prior process. This is not what Congress stated or intended when it enacted section 7(i).

In *APAC v. Bonneville Power Administration*, 126 F. 3d 1158 (9th Cir. 1997), the Ninth Circuit noted that "the section 7(i) proceeding is appropriate only when BPA is establishing a true rate." 126 F. 3d at 1177. The Court observed that the Northwest Power Act does not define "rate," and therefore "[a]bsent a statutory imperative, we must defer to BPA's definition if reasonable." *Id*. at 1176. The Court turned to BPA's rules of procedure, stating:

> Since at least 1986, BPA has defined "rate" in the context of section 7(i) proceedings as follows:
>
> "Rate" means the monetary charge, discount, credit, surcharge, pricing formula or pricing algorithm for any electric power or transmission service provided by BPA . . .

Procedures Governing Bonneville Power Administration Rate Hearings §1010.2(j), 51 Fed. Reg. 7611, 7615 (1986). BPA thus defines a "rate" as a monetary charge for the sale of electric power.

Clearly, the Principles do not establish monetary charges for the sale of electric power. Rather, they are a set of principles "intended to 'keep the options open' for future fish and wildlife decisions that are anticipated to be made . . . on reconfiguration of the hydrosystem and . . . on the Northwest Power Planning Council's Fish and Wildlife Program." Revenue Requirement Study Documentation, Vol. 1, WP-02-E-BPA-02A, at 354. These are strictly policy and program level determinations. Contrary to the IOUs' allegation in their brief on exceptions that "[t]he Administrator ignored the argument raised by the DSIs that in previous rate cases fish and wildlife program costs were addressed within the 7(i) process," IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 73, BPA has explained in detail why the section 7(i) rates process does not apply to the Principles.

A section 7(i) rates process is not the appropriate forum for debating either the policy reasons for, or the biological merits of, potential strategies for fish and wildlife recovery. At this time, there is no consensus regarding which Fish and Wildlife Alternative should be implemented, or even which Alternative is most likely to result in better salmon recovery. Evidence of this lack of consensus can be found in disparate arguments presented by various parties to this rate case. For example, CRITFC/Yakama claim that Fish and Wildlife Alternative 13u [involving dam breaching] is the most similar to the Nez Perce, Umatilla, Warm Springs, and Yakama tribes' comprehensive salmon recovery plan. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 20. On the other hand, PPC claims that "the likelihood that dam breaching will be approved by federal agencies in 2000 and implemented prior to 2006 has been significantly reduced in the last few months." PPC Brief, WP-02-B-PP-01, at 48. Further, "the failure of fish and wildlife agencies to identify a way to increase harvest while increasing survival of protected fish is an indication that they are not close to a realistic plan yet." *Id*.

Other parties acknowledge that this rate proceeding is not the appropriate forum to discuss fish and wildlife alternatives. In oral argument, UCUT states that "[it] does not want the Fish and Wildlife Alternatives debated in the rate case. Those issues are better debated in forums where we have experts and a number of different people able to comment and help us with that decision." Oral Tr. 172. Ongoing discussions among the various fish and wildlife agencies, Indian tribes, and other interested parties in other forums will form the basis for future fish and wildlife decisions.

Since these Principles represent strictly policy and program level determinations, BPA decided there is no obligation to subject these Principles to the ratemaking procedures of section 7(i) of the Northwest Power Act.

<u>Section 4(h)(10) of the Northwest Power Act Does Not Subject Fish and Wildlife Funding Determinations to a Section 7(i) Hearing.</u>

Section 4(h) of the Northwest Power Act reinforces the conclusion that the Principles were properly excluded from reconsideration in the rate case. 16 U.S.C. §839b(h). Section 4(h)(10) contains extensive provisions regarding proposed fish and wildlife projects and describes BPA's responsibilities for funding these projects. 16 U.S.C. §839b(h)(10). Although section 4(h)(10) contains a detailed discussion of BPA's fish and wildlife funding obligations, there is no language stating or implying that BPA's fish and wildlife program determinations are subject to a section 7(i) hearing. On the contrary, section 4(h)(10) acknowledges that BPA's fish and wildlife program funding determinations are ultimately subject to a separate level of review. These determinations are reviewed by Congress as part of BPA's overall budget.

Section 4(h)(10)(A) of the Northwest Power Act states, "[t]he Administrator shall use the Bonneville Power Administration fund and the authorities available to the Administrator under this [Act] and other laws administered by the Administrator to protect, mitigate, and enhance fish and wildlife . . . ." 16 U.S.C. §839b(h)(10)(A). Section 4(h)(10)(B) states that "[t]he Administrator may make expenditures from such fund which shall be included in the annual supplementary budgets submitted to the Congress pursuant to the Federal Columbia River Transmission System Act [16 U.S.C. §838 et seq.]." 16 U.S.C. §839b(h)(10)(B).

In 1974, the Transmission System Act made BPA self-financing by establishing the BPA fund (hereinafter referred to as the "fund") in the U.S. Treasury. 16 U.S.C. §838i. The fund includes all of BPA's receipts from the sale of power and transmission services and all proceeds from BPA's sale of bonds to the Treasury. *Id*. Congress made a permanent appropriation of this fund to BPA, authorizing BPA to make expenditures from the fund which have been included in its annual budget submitted to Congress, subject only to specific Congressional directives or limitations. *Id*. In the instant case, given the specific language of section 4(h)(10), there is no doubt that the Federal budget process, not the BPA rate case, is the proper forum for review of program level determinations related to BPA's fish and wildlife program.

In section 4(h)(11)(B), Congress envisioned that BPA, in carrying out its fish and wildlife responsibilities under section 4(h), would coordinate with state and Federal fishery agencies, Indian tribes, and others:

> The Administrator and such Federal agencies shall consult with the Secretary of the Interior, the Administrator of the NMFS, and the State fish and wildlife agencies of the region, appropriate Indian tribes, and affected project operators in carrying out the provisions of this paragraph and shall, to the greater extent practicable, coordinate their actions.

16 U.S.C. §839b(h)(11)(B).

This, of course, is precisely what BPA did in the instant case.

The Principles were not developed by BPA alone. Rather, they were developed in a public process that included virtually all stakeholders throughout the region and were ultimately endorsed and announced by Vice President Gore. Nothing in the Northwest Power Act requires BPA to subject these Principles to an evidentiary hearing in a BPA rate proceeding. Moreover, to do so would not only serve no useful purpose, but would undermine the integrity of the public process that led to the Principles.

The United States Court of Appeals for the Ninth Circuit has recognized on many occasions that "[i]t is the responsibility of the Administrator to manage the complex relationship among these various aspects of [BPA's] statutes." *APAC*, 126 F. 3d at 1180. BPA believes that its decision to exclude testimony on the policy merits or wisdom of the Principles is consistent with and supported by the express language of sections 7(i) and 4(h)(10) of the Northwest Power Act.

<u>Limiting the Scope of Fish and Wildlife Issues to be Addressed in the Power Rate Proceeding Does Not Violate the Due Process Clause of the Fifth Amendment to the U.S. Constitution.</u>

The IOUs argue in their brief on exceptions that "[e]xclusion of the 13 Fish and Wildlife Alternatives from this case constitutes legal error and violates the parties' statutory due process rights under Section 7(i)." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 74.

The PPC argues that "BPA's preemptive actions [excluding discussion of certain fish and wildlife information] essentially impair the rights of BPA's customers to present the information necessary to justify lower or revised rates. This in turn is in violation of the Due Process Clause of the Fifth Amendment to the U.S. Constitution . . ." PPC Brief, WP-02-B-PP-01, at 47.

The PPC also claims that "[i]t is persuasive that not only do BPA's customers believe they have been deprived of due process of law by the limitations imposed by BPA in the rate case, but that the Hearing Officer herself shared the same concerns. *See* Tr. 674." PPC Brief, WP-02-B-PP-01, at 47.

PPC's due process argument is without merit. As discussed in more detail in the introduction to ROD section 2.3, *supra*, the Principles were developed in an extensive public involvement process that included numerous Federal agencies (including NMFS, USFWS, Reclamation, COE, and EPA), state agencies, the Northwest Congressional delegation, Columbia Basin Tribes, public interest groups, BPA customers, and interested members of the public. 64 Fed. Reg. 44318, 44321 (1999).

The public involvement process focused on providing guidelines for structuring BPA's approach to Subscription in order to ensure that BPA could meet its financial obligations, including those for fish and wildlife. DeWolf *et al.*, WP-02-E-BPA-39, at 21. Of necessity, BPA must move forward in setting rates for the post-2001 rate period, in large part because it must negotiate new power sales contracts for the post-2001 rate period. *Id.* at 22-23. The Principles recognized the impossibility of accomplishing either of these tasks if uncertainties about fish and wildlife funding costs remained. *Id*. at 23. For this reason, a range of alternatives and associated costs are specified in the Principles. *Id*. It would be impractical and serve no policy purpose for BPA to resurrect and explore once again the myriad issues that have already been fully aired and addressed in these other public review processes. *Id.* at 25.

Notwithstanding the implication that BPA allowed no discussion of fish and wildlife issues in this rate proceeding, the Federal Register Notice specifically described several issues that were not addressed in the Principles and would be addressed in the rate proceeding:

> Fish and wildlife issues that will be addressed in this rate proceeding include: (1) how the terms of access to the FCCF are modeled in the rate proposal and their impact on TPP and rates; (2) how section 4(h)(10)(C) credits are modeled in the rate proposal and their impact on TPP and rates; (3) the calculation and treatment of O&M and capital investment in repayment studies and the revenue requirement; (4) the selection, design, terms and conditions, assumptions, treatment, and impact of planned net revenues for risk, CRAC, indexed power sales contracts, stepped rates, and targeted adjustment charge; (5) the RiskMod, NORM, and Tool Kit model design, operation, inputs and outputs, and use of results; (6) the level of TPP that is targeted, from the range of potential TPP targets established in the Principles; and (7) the design, terms and conditions, assumptions, and treatment of the DDC, including the threshold for triggering a dividend distribution, the conditions under which a dividend is distributed, and the mechanism used to distribute dividends to certain power customers.

64 Fed. Reg. 44318, 44322 (1999).

Nothing in the Northwest Power Act requires BPA to subject the Principles to an evidentiary hearing in a BPA rate proceeding. Moreover, to do so would not only serve no useful purpose, but would undermine the integrity of the prior public process that fully afforded all interested parties ample opportunity to provide comments.

<u>Decision</u>

BPA has provided the parties with an opportunity to fully and fairly examine all fish and wildlife issues that should be examined in ratesetting, thus allowing the development of a full and complete record in this section 7(i) proceeding. Nothing in the Northwest Power Act requires BPA to subject the Principles to an evidentiary hearing in a BPA rate proceeding. Moreover, to *do so would not only serve no useful purpose, but would undermine the integrity of the public process that led to the Principles.*

Issue 3

Whether issues pertaining to including increased funding for cultural resource protection in BPA's revenue requirement are within the proper scope of the rate case.

Parties' Positions

UCUT argues that $3.5 million has been budgeted in years past for cultural resource protection, and that this amount has historically and consistently been inadequate to complete program requirements and comply with Federal law. Osterman, WP-02-E-UC-01, at 2; UCUT Brief, WP-02-B-UC-01, at 9. UCUT argues that BPA must include a revenue requirement for cultural resources that is adequate to meet Federal law and BPA's fiduciary trust obligation to act with a high degree of care and responsibility to the Indian tribes of the region. UCUT Brief, WP-02-B-UC-01, at 10.

UCUT disagrees in its brief on exceptions with BPA's statement that there are no rate case issues pertaining specifically to funding of programs for cultural resource protection and that the issue is outside the scope of the rate case. UCUT Ex. Brief, WP-02-R-UC-01, at 2.

The Shoshone-Bannock Tribes state that "the Upper Columbia United Tribes have set forth the concerns of the Tribes regarding the inadequacy of funding for cultural resource concerns . . . ." Shoshone-Bannock Brief, WP-02-B-SH-01, at 9. Therefore, the Shoshone-Bannock Tribes support and join in the position taken by the UCUT in its initial brief. *Id*.

CRITFC/Yakama state that "Bonneville must include a revenue requirement for cultural resources which is adequate to meet federal law and its fiduciary trust obligation to act with a high degree of care and responsibility to the Indian tribes of the region." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 36. "CRITFC/Yakama hereby incorporate by reference the arguments and evidence put forward by the Upper Columbia United Tribes in its initial brief regarding BPA's legal obligation to include increased funding for cultural resources in its revenue requirements study." *Id*.

BPA's Position

BPA shares the Federal Government's trust obligations to Indian tribes. Neither Congress nor the Executive branch has delegated BPA specific trust-related duties to manage an Indian resource on behalf of Indian beneficiaries. *See* BPA's discussion of its trust responsibilities, *supra*. BPA is responsible for the power-related cultural resources costs of COE and Reclamation.

In the Federal Register Notice announcing the power rate proceeding, BPA described with particularity the nature and scope of the proceeding. 64 Fed. Reg. 44318 (1999). BPA explained that four major public consultation and review processes had been undertaken by BPA in the past five years, and that the rate case would implement policy decisions reached in those processes. *Id*. at 44319-23. The four major public processes referred to are the Business Plan public process, the Cost Review process, the Subscription Strategy process, and the Principles process. *Id.* BPA stated that it would not revisit in the rate case any policy determinations previously made in any of these forums. *Id*.

BPA's approach during the rate proceeding was to incorporate the results of these processes, as appropriate, into the rate proceeding and provide an opportunity for the parties to test the impact of those policy determinations on BPA's rates. Policy level determinations and program levels are not properly the subject of a section 7(i) hearing. Section 7(i) of the Northwest Power Act is applicable to the establishment of rates only, not broad policy or program level determinations such as program goals and objectives, processes, priorities, and allocation of resources, that may impact rates. These are strictly policy and program level determinations. Further, a section 7(i) process is not the appropriate forum for debating the policy reasons for specific funding levels necessary for cultural resources. *See* Issue 2, *supra*.

See also ROD section 5.3.2, entitled "Fish and Wildlife and Cultural Resources Expenses," *supra*. BPA has not yet developed program levels for the FY 2002-2006 rate period. It has, however, developed an estimate of costs sufficient for the purpose of setting rates.

<u>Evaluation of Positions</u>

UCUT argues that BPA, COE, and Reclamation have numerous obligations to protect historic places, burial sites, archaeological sites, traditional cultural properties, and human remains. UCUT Brief, WP-02-B-UC-01, at 6. These obligations exist when new Federal actions are initiated and are continuing obligations after sites are identified. *Id.* Existing river operations from COE and Reclamation actions can wash out or impact existing cultural sites. *Id.*

BPA's responsibility is limited to the power-related costs of COE and Reclamation. 16 U.S.C. §839d-1. As BPA's witness stated:

> Q. . . . To your knowledge BPA is responsible for the power-related costs and other agreed-upon costs of the COE and Reclamation, including the cultural resources protection costs, and these costs should be reflected in the revenue requirements study?
>
> A. (Ms. Lefler) To the extent they are allocated to power purposes they would be.

Tr. 507.

In a response to a data request from UCUT (which UCUT has included as an exhibit), BPA described where in the generation revenue requirements its funding levels for cultural resources are reflected. The O&M direct funding agreements BPA has with COE and Reclamation include funding for cultural resources. UCUT Exhibit, WP-02-E-UC-02 (BPA Data Response to Request No. UC-BPA:015). During the rate period, the direct funding agreement with COE includes $2.5 million per year (for cultural resources compliance), and the direct funding agreement with Reclamation includes $1 million per year. *Id.* Additionally, the BPA fish and wildlife budget includes $200,000 per year of administrative expenses associated with the $3.5 million. *Id.* Additional funds for cultural resource management associated with fish and wildlife projects are assumed embedded within individual project budgets as a miscellaneous administrative expense and will vary considerably from one project to another. *Id.* The amount needed will depend on each project's potential to affect cultural resources (in many cases, there may be no potential to affect cultural resources) and the project's particular circumstances (such as amount of land area involved and resource protection needs). *Id.* There is no separate budget line item for cultural resource management in the fish and wildlife program. *Id.*

Further, the Principles do not establish a budget for the 2002-2006 period, and BPA is not picking a single number for the rate case. Volume 1, Attachment 1, Revenue Requirement Study Documentation, WP-02-E-BPA-02A, at 354. The 13 Fish and Wildlife Alternatives "represent a set of assumptions, a forecasting convention, to establish capital investment and O&M levels, system operations assumptions, and risk analysis assumptions for purposes of setting rates." DeWolf *et al*., WP-02-E-BPA-13, at 10. Cost estimates will continue to evolve as the analysis, planning, and decision process for system reconfiguration and related actions progress. *Id*.

UCUT does not object to the inclusion of BPA's cultural resource funding obligations in COE and Reclamation O&M line items; UCUT merely argues that the amount included is not adequate--the $3.5 million that has been budgeted in years past for cultural resource protection has historically and consistently been inadequate to complete program requirements and comply with Federal law. Osterman, WP-02-E-UC-01, at 2; UCUT Brief, WP-02-B-UC-01, at 9.

UCUT also argues that BPA must include in its revenue requirement an amount for cultural resource protection that is adequate to meet Federal law and BPA's fiduciary trust obligation to the Indian tribes of the region to act with a high degree of care and responsibility. UCUT Brief, WP-02-B-UC-01, at 10. UCUT introduces evidence suggesting that "$10.5 million per year is a reasonable sum for bringing the existing cultural resources protection program into compliance with law." *Id.* UCUT derived this number "by doubling the current budget of $3.5 million (since $3.5 million has been historically and consistently inadequate to comply with federal law). We then added an additional $3.5 million to 'catch up' on the cultural resources programs which were foregone during the last rate period due to Kennewick Man." *Id.* In addition, UCUT states that an inadvertent discovery fund totaling $5 million for the rate period should be created. *Id.* CRITFC/Yakama support UCUT's suggestion to include $10.5 million per year in BPA's budget for cultural resources. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 36. UCUT also states that "BPA should review the cultural resources budgets for the 13 alternatives and increase those budgets as necessary to continue a practice of compliance with federal cultural resources law." UCUT Brief, WP-02-B-UC-01, at 10.

BPA and the other parties to this rate case were given no opportunity to examine and rebut UCUT's suggestion that BPA should include these significant additional amounts in its generation revenue requirements for cultural resources protection, or the basis underlying these additional amounts. Furthermore, it is beyond the scope of this power rate proceeding for UCUT to argue the appropriateness or reasonableness of BPA's decisions on spending levels. Nevertheless, BPA disagrees with UCUT's suggestions. As BPA stated *supra*, the O&M direct funding agreements BPA has with COE and Reclamation include funding for cultural resources. UCUT Exhibit, WP-02-E-UC-02 (BPA Data Response to Request No. UC-BPA:015). These amounts are reflected in BPA's generation revenue requirements. However, these amounts are subject to change in the agencies' budget processes. These amounts may also be changed by Congress in the appropriations process. BPA recognizes that there is risk and uncertainty associated with COE and Reclamation direct funding. The NORM was developed to capture risks other than operational risks in the ratesetting process. Conger *et al*., WP-02-E-BPA-15, at 17. These non-operating risks include uncertainties in the capital costs, expenses, and BPA's direct program O&M costs associated with the 13 Fish and Wildlife Alternatives. *Id.*

UCUT also discusses selected case law, statutes, executive orders, regulations, and policies (including BPA's Tribal Policy) that show UCUT's view of BPA's fiduciary trust obligation to them. UCUT Brief, WP-02-B-UC-01, at 6-8. As discussed in more detail *supra*, the Federal Government recognizes the "undisputed existence of a general trust relationship between the United States and the Indian people." *United States v. Mitchell*, 463 U.S. 206, 225 (1983). BPA shares the Government's trust responsibility to Indian tribes. Neither Congress nor the Executive branch has delegated BPA specific trust-related duties to manage an Indian resource on behalf of Indian beneficiaries. When such a specific trust responsibility is established, an agency must fulfill this responsibility as a "moral obligation [] of the highest responsibility" to "be judged by the most exacting fiduciary standards." *Seminole Nation v. United States*, 316 U.S. 286, 297 (1942). BPA fulfills its trust responsibility by working with the PNW region's tribes in the manner prescribed by DOE and BPA tribal policies and by fully complying with the laws governing its activities.

With respect to limitations on BPA's responsibilities, UCUT quotes one of BPA's witnesses for the proposition that "BPA is responsible for the power-related costs of the Corps of Engineers and the Bureau of Reclamation." UCUT Brief, WP-02-B-UC-01, at 6. UCUT does not object to BPA's interpretation of its responsibilities. BPA cannot direct fund more than the share of cultural resource costs on the FCRPS allocated to power, because to do so might violate principles of appropriations law. *See* 31 U.S.C. §1532 and §1301(a). In addition, BPA is generally not considered a hydrosystem operator or Federal land manager. BPA does not have direct control over the impacts of the FCRPS on cultural resources. This responsibility resides with COE and Reclamation.

Section 7(i) of the Northwest Power Act is applicable to the establishment of rates only, not broad policy or program level determinations. BPA has not developed program levels for the FY 2002-2006 rate period. Further, the cost estimates used in setting rates do not constrain BPA from meeting its legal responsibilities in the future.

Decision

While BPA shares the Federal Government's trust obligations to Indian tribes, neither Congress nor the Executive branch has delegated BPA specific trust-related duties to manage an Indian resource on behalf of Indian beneficiaries. BPA's legal obligations for funding cultural resource protection are met through payment of its power-related share of costs in COE and Reclamation

O&M direct funding agreements. Thus, issues pertaining specifically to funding of programs for cultural resource protection are not within the scope of the rate case.

Issue 4

Whether the initial rate proposal complies with BPA's tribal trust and fiduciary obligations.

Parties' Positions

CRITFC/Yakama state that "Bonneville, like the federal government and its agencies, is subject to the United States' fiduciary responsibilities to tribes. *See e.g., Pyramid Lake Paiute Tribe of Indians v. United States Department of the Navy*, 898 F.2d 1401 [sic], 1411 [citing to headnotes] (9th Cir. 1991) . . ." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 7.

CRITFC/Yakama claim that:

> Bonneville, as an agency of the United States, has a clear and distinct treaty-based obligation to preserve and ensure that Columbia River salmon are available to support the tribes' fisheries. *See Confederated Tribes of the Umatilla Indian Reservation v. Callaway*, No. 72-211 (D.Or. August 17, 1973)(consent decree). In *Callaway*, the court ordered the Department of the Interior and the COE to manage and operate the FCRP's peak power operations in a manner that did not "impair or destroy" the tribe's treaty fishing rights. The Administrator also has a fiduciary duty to protect and preserve the tribes' fisheries.

CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 19.

CRITFC/Yakama state that "Bonneville's actions are subject to scrutiny under the most exacting fiduciary standards," CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 20, and cite *Seminole Nation v. United States*, 316 U.S. 286, 297 (1942) for the proposition that "[the Government's] conduct, as disclosed in the acts of those who represent it in dealing with the Indians, should therefore be judged by the most exacting fiduciary standards." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 20.

CRITFC/Yakama state in their brief on exceptions that "[a]fter reviewing the Draft Record of Decision it appears that Bonneville has addressed one of the 34 issues raised in our brief. We do not believe that Bonneville's treatment of the numerous issues we raised in our brief comes anywhere close to addressing Bonneville's Treaty, trust, and fiduciary obligations to our tribes." CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 2.

The Shoshone-Bannock Tribes state that BPA, as a Federal agency, has the same trust responsibility to Indian tribes as any other agency of the Federal Government. Shoshone-Bannock Brief, WP-02-B-SH-01, at 8. The Shoshone-Bannock Tribes argue that "BPA has failed to demonstrate that the [Keep the Options Open] policy will indeed protect the resources and interests of the Tribes. Ten (10) Indian Tribes have believed it necessary to intervene in this rate case . . . in order to show where BPA has been found lacking in carrying out its trust responsibilities." *Id*. at 9.

UCUT states that BPA (and COE and Reclamation) have a legal trust responsibility to the region's Indian tribes when tribal cultural, spiritual, or important sites are involved in Federal actions. UCUT Brief, WP-02-B-UC-01, at 7.

<u>BPA's Position</u>

Given the strictly legal nature of the parties' arguments regarding BPA's tribal trust and fiduciary obligations, BPA witnesses did not address this issue in testimony. As a Federal agency, BPA shares the Government's trust responsibility to Indian tribes. BPA fulfills its trust responsibility by working with the PNW region's tribes in the manner prescribed by DOE and BPA tribal policies and by fully complying with the laws governing its activities.

<u>Evaluation of Positions</u>

UCUT in its brief on exceptions argues that:

> BPA uses the lack of a specifically delegated trust property managed by BPA on behalf of Indian beneficiaries to disclaim any trust responsibility to the region's tribes. Instead, it characterizes its responsibility as "working with" tribes and "fully complying with the laws governing its activities." BPA cites no treaty, Federal statute or case law establishing a "working with" standard.

UCUT Ex. Brief, WP-02-R-UC-01, at 2.

UCUT acknowledges that BPA lacks any specifically delegated trust property that it manages on behalf of Indian beneficiaries. However, UCUT then tries to weave an argument that in some way BPA has disclaimed any trust responsibility to the region's tribes because BPA has no such delegated trust property. This could not be further from the truth. BPA expressly acknowledges that it shares the Government's trust responsibility to Indian tribes. It is also difficult to understand UCUT's assertion that BPA errs in some way because BPA does not cite to any treaty, Federal statute, or case law establishing a "working with" standard. There is simply no reason for BPA to cite to any such authority, because BPA makes no such allegation that it is complying with UCUT's so-called "working with" standard.

The Shoshone-Bannock Tribes state that "[i]t is well established that the United States has a solemn trust obligation to Indian people." Shoshone-Bannock Brief, WP-02-B-SH-01, at 5. "The source of the federal government's trust responsibility is established by the provisions of treaties, agreements, statutes, and 'reinforced by the undisputed existence of a general trust relationship between the United States and Indian people.' *United States v. Mitchell,* 463 U.S. 206, 226 [sic] (1983)." *Id*.

CRITFC/Yakama state that "Bonneville, like the federal government and its agencies, is subject to the United States' fiduciary responsibilities to tribes. *See e.g.*, *Pyramid Lake Paiute Tribe of*

Indians v. United States Department of the Navy, 898 F.2d 1401 [sic], 1411 [citing to headnotes] (9th Cir. 1991) . . ." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 7.

CRITFC/Yakama also state that "Bonneville's actions are subject to scrutiny under the most exacting fiduciary standards," CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 20, and cite *Seminole Nation v. United States*, 316 U.S. 286, 297 (1942) for the proposition that "[the Government's] conduct, as disclosed in the acts of those who represent it in dealing with the Indians, should therefore be judged by the most exacting fiduciary standards." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 20.

CRITFC/Yakama allege that "Bonneville's fiduciary responsibilities to the tribes' [sic] and their treaty secured interest dictate that a higher standard of care must be exercised in this proceeding as it affects these tribal interests." CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 7.

The Federal Government recognizes the "undisputed existence of a general trust relationship between the United States and the Indian people." *United States v. Mitchell*, 463 U.S. 206, 225 (1983) [hereinafter *U.S. v. Mitchell*]. BPA shares the Government's "general" trust responsibility to Indian Tribes. In *U.S. v. Mitchell*, the Supreme Court required the elements of a common law trust be present to make the trust responsibility enforceable. The elements of a trust are: (1) a trust property; (2) managed by a Federal agency under specific statutory guidance; (3) on a behalf of Indian beneficiaries. *Id*. at 220-22. In its brief on exceptions, CRITFC/Yakama argue that "Bonneville's position is based upon and [sic] incomplete analysis of *Mitchell* and citation to authority that is not controlling in the Ninth Circuit Court of Appeals . . ." CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 31. CRITFC/Yakama quote *U.S. v. Mitchell* for the proposition that the court does recognize that a trust relationship may exist even where there is no specific statutory delegation of trust duties.

> Where the Federal Government takes on or has control or supervision over tribal monies or properties, the fiduciary relationship normally exists with respect to such monies or properties (unless Congress has provided otherwise**)** *even though nothing is said expressly in the authorizing or underlying statute (or other fundamental document) about a trust fund, or a trust or fiduciary commitment.*

U.S. v. Mitchell, 463 U.S. 206, 225 (1983) (emphasis added, citations omitted). CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 31.

The law regarding the government's trust responsibility is well-established. Nothing the parties or BPA say here will alter the law. No amount of briefing in this rate case will change BPA's trust responsibility, nor is this rate proceeding the appropriate forum for determining BPA's treaty and trust obligations. Further, it is not treaty and trust law at issue in this rate case; rather, it is how the tribes believe BPA should integrate this established body of law into its risk analysis. Therefore, BPA has not attempted to respond to every one of CRITFC/Yakama's arguments regarding its interpretation of BPA's treaty and trust responsibilities.

Notwithstanding CRITFC/Yakama's interpretation of *U.S. v. Mitchell*, the tribes can cite to no evidence on the record regarding trust assets or properties controlled or managed by BPA on behalf of Indian beneficiaries.

Federal agencies and tribes look to Congress and the Executive Branch to delegate specific trust duties to agencies through statutes or executive orders. Neither Congress nor the Executive Branch has delegated BPA specific trust-related duties to manage an Indian resource on behalf of Indian beneficiaries. Therefore, BPA fulfills its trust responsibilities by working with the PNW's tribes in the manner prescribed by the DOE and BPA tribal policies, and by fully complying with the laws governing its activities. *See, generally*, *United States v. Mitchell*, 463 U.S. 206, 225 (1983); *North Slope Burough v. Andrus*, 642 F.2d 589 (D.C. Cir. 1980).

CRITFC/Yakama argue in their brief on exceptions that:

> BPA owes the tribes a fiduciary trust responsibility independent of statute. *Pyramid Lake Paiute Tribe v. Dept. of Navy*, 898 F.2d 1410, 1420 (9th Cir. 1990). BPA can not fulfill that responsibility simply by analyzing its own Northwest Power Act and determining that by complying with the Northwest Power Act that it is fulfilling its "highest and best fiduciary" responsibility to the Yakama and CRITFC Tribes.

CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 33.

BPA does not agree that *Pyramid Lake* stands for the proposition that BPA owes the tribes a fiduciary trust responsibility independent of statute. Furthermore, the citation CRITFC/Yakama references does not describe any such responsibility. BPA is not persuaded by this unsupported allegation.

In their brief on exceptions, CRITFC/Yakama also argue that:

> BPA has a trust responsibility to the tribes and it cannot discharge its trust responsibilities simply by complying with its governing statutes. *See Nance v. Environmental Protection Agency*, 645 F.2d 701, 710-11 (9th Cir. 1981) (holding that in designating airshed quality under the CLA, the Federal Government owes a trust responsibility to the tribe beyond the statutory and regulatory obligations owed to the general public). Rather, BPA must specifically consider the tribes' interests and act affirmatively to protect those interests. BPA may not, as it has done, balance tribal interests in order to effect a compromise.

CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 32.

BPA believes that *Nance v. EPA* stands for the proposition that "any Federal government action is subject to the United States' fiduciary responsibilities toward the Indian tribes." *Id*. at 711. However, as discussed in numerous Ninth Circuit and other cases, absent statutory, regulatory, or judicial guidance, it is unclear exactly what more, if anything, an agency must do in a particular circumstance to fulfill its trust responsibility. *See Inter Tribal Council of Arizona, Inc. v.*

Babbitt, 51 F.3d 199, 203 (9th Cir. 1995), where the court cites to the *U.S. v. Mitchell* standard that the Federal government can incur specific fiduciary duties toward particular Indian tribes when an agency manages or operates Indian lands or resources. *See, also, Morongo Band of Mission Indians v. Federal Aviation Administration*, 161 F.3d 569 (9th Cir. 1998). Here the court stated:

> . . .[A]lthough the United States does owe a general trust responsibility to Indian tribes, unless there is a specific duty that has been placed on the Government with respect to Indians, this responsibility is discharged by the agency's compliance with general regulations and statutes not specifically aimed at protecting Indian tribes.

Id. at 574.

In *United States v. 1020 Electronic Gambling Machines*, 38 F.Supp.2d 1219 (E.D. Wash. 1999), the court examined the question whether a general trust obligation can support the existence of a specific fiduciary duty, and found in the affirmative, but went on to say:

> . . . but only where there are statutes or regulations that clearly impose such a duty. *Mitchell II*, 463 U.S. at 225, 103 S.Ct. at 2972. By itself, a general trust duty is not enough to establish the existence of a specific duty. *United States v. Mitchell*, 445 U.S. 535, 546, 100 S.Ct. 1349, 1355, 63 L.Ed.2d 607 (1980) (*Mitchell I*).

Id. at 1225.

BPA is not persuaded by CRITFC/Yakama's argument given the absence in the evidentiary record of any trust assets or properties controlled or managed by BPA on behalf of Indian beneficiaries.

UCUT joins the legal argument of CRITFC/Yakama regarding the trust responsibility. UCUT Ex. Brief, WP-02-R-UC-01, at 2.

CRITFC/Yakama claim that Fish and Wildlife Alternative 13u is the most similar to the Nez Perce, Umatilla, Warm Springs, and Yakama Tribes' comprehensive salmon recovery plan. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 20. CRITFC/Yakama argue that BPA's approach gives a very low probability to the alternative that would implement the tribes' salmon recovery plan "on a schedule that might provide any chance of an improved Treaty fishery within the next generation of tribal members (Alternative 13u)." *Id*. CRITFC/Yakama also argue that BPA's approach gives low weight "to the alternative most likely to achieve survival and recovery of Snake River spring/summer chinook listed under the ESA and meet Bonneville's Treaty and trust obligations (Alternative 8u)." *Id.* at 20-21. CRITFC/Yakama allege that "Bonneville's assumption is clearly inconsistent with federal Treaty and tribal trust obligations. It is also inconsistent with Bonneville's stated policy of keeping the options open." *Id*. at 21.

CRITFC/Yakama state that “Alternative 13u, if chosen, would put Bonneville’s Treasury Payment Probability at about 65% which would violate Fish and Wildlife Funding Principle #3 . . . Furthermore, there is a high likelihood that a Treasury Payment Probability (TPP) of 65% would mean that, under the current Proposal, Bonneville would not be able to fully fund the fish and wildlife measures. This would be a violation of Fish and Wildlife Funding Principle #1 and a violation of the tribes’ treaty rights.” CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 21-22. CRITFC/Yakama argue that “[b]ecause the Proposal, as it exists, fails to address this fact and because the Proposal does not address the risk that alternative 13u is the most likely to provide for fish and wildlife recovery, the Proposal is deficient and should be changed to comply with Principles #1 and #3 and with the tribes’ treaty rights.” *Id*. at 22.

Although CRITFC/Yakama favor Alternative 13u, this Alternative differs from Alternative 13a only with respect to timing. Also, Alternative 13a has a conditional TPP that is substantially higher than the 65 percent TPP that CRITFC/Yakama cite for Alternative 13u. DeWolf *et al*., WP-02-E-BPA-39, Attachment 4, at 5. The timing assumptions supporting Alternative 13u are, for all intents and purposes, no longer supportable. Alternative 13u assumes that Congress will authorize breach of the four lower Snake River Dams, modify John Day Dam to create natural river conditions, and implement measures to bring dams into compliance with the CWA. Revenue Requirement Study Documentation, Vol.1, WP-02-E-BPA-02A, at 371-72. Alternative 13u also assumes that Congress will appropriate in the current Federal budget process over $200 million for these purposes. *Id*. at 373. There is a significant possibility that “unadjusted” schedules for Alternatives involving dam breaching (such as alternative 13u) could not be met. *Id*. at 349. No regional consensus has formed around Alternative 13u, and no such proposal is being made or considered by Congress at this time.

CRITFC/Yakama argue that “[w]hen Columbia Basin tribes suggested that Bonneville could cover all the fish and wildlife options and still have rates that were 25 percent below the market projections for electricity we were told that Bonneville could not raise rates. Bonneville’s policy against raising rates is counter to Bonneville’s trust and fiduciary responsibilities.” CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 26.

CRITFC/Yakama further argue in their brief on exceptions that they should be afforded some special status in this rates proceeding, and to do otherwise is a violation of BPA’s treaty, trust, and fiduciary obligations to the tribes.

> . . . [A]ll of the responsible alternatives for meeting BPA’s Treaty and environmental responsibility will cost much more after 2006. BPA must position itself to meet these costs and remain competitive. BPA cannot ignore these facts simply because there is not a consensus among all of its customers. BPA, utilities, and large industries are not sovereign governments. They are not resource managers. They cannot veto the decisions of entities that are sovereigns and resource managers. Lack of a consensus does not eliminate BPA’s Treaty and trust obligations to the tribes or its responsibility to follow Federal law. In fact, such a lack of consensus heightens BPA’s obligations to see that the trust responsibility is fulfilled.

CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-01, at 6. CRITFC/Yakama continue:

> It is not appropriate to treat the views of sovereigns and fishery managers the same as a utility trade association. This clearly violates BPA's Treaty, trust, and fiduciary obligations. It is also not appropriate for BPA to conclude that there is not clear science on what measures are needed to meet Treaty and fish and wildlife protection obligations. BPA may not substitute its judgement for fishery managers. It may not use the excuse that since some utilities which benefit from the dams but have no responsibility to restore fish and wildlife do not support some measures, that the restoration actions are unlikely to be implemented. Such a use inappropriately elevates a special interest over the public interest. It places a commercial interest over the views of sovereigns that are protected by a long-standing Treaty with the United States.

Id. at 14.

Notwithstanding CRITFC/Yakama's position that tribal interests should override other competing interests, the fact that there are competing positions with respect to fish and wildlife restoration reinforces the need to "keep the options open" for future fish and wildlife decisions. Thus, the 13 Fish and Wildlife Alternatives represent a set of assumptions, a forecasting convention, to establish capital investment and O&M levels, system operations assumptions, and risk analysis assumptions for purposes of setting rates. DeWolf *et al.*, WP-02-E-BPA-13, at 9. In addition, the fact that CRITFC/Yakama and other Indian tribes are parties in this rate proceeding does not mean that these tribes should be afforded any special status with respect to their participation in the rate case. In contrast to the due weight given to the tribes' views pursuant to section 4(h)(7) of the Northwest Power Act (16 U.S.C. §839b(h)(7)), the section 7(i) ratemaking procedures describe a more general process open to "any person." 16 U.S.C. §839e(i). All parties in the rate case are afforded the same rights and have the same obligations.

CRITFC/Yakama allege that BPA's actions in this rate proceeding in some way violate BPA's trust and fiduciary responsibilities. However, CRITFC/Yakama cite only case law for the general proposition that BPA, as a Federal agency, has a general trust responsibility to Indian tribes. CRITFC/Yakama can cite to no statute, law, or executive order that establishes a BPA-specific trust-related responsibility as defined in *U.S. v. Mitchell.* BPA complies with its own tribal policy and that of the DOE. In addition, BPA follows the Clinton Administration's view of the Federal trust responsibility to the Columbia River treaty tribes and the relationship between this Federal responsibility and the ESA. *Letter from Terry D. Garcia, NOAA Assistant Secretary for Oceans and Atmosphere, to Ted Strong, CRITFC Executive Director* (July 21, 1998) (stating the twin goals of Federal policy being recovery and delisting of ESA listed salmonids and restoration of salmonid populations over time to provide meaningful exercise of treaty fishing rights). None of these policies, however, creates legal obligations for BPA to take specific actions, such as funding drawdown of lower Snake River Dams or adopting Fish and Wildlife Alternative 13u.

Decision

BPA's initial rate proposal complies with BPA's tribal trust and fiduciary obligations. BPA fulfills its trust responsibility to the region's tribes by working with them in the manner prescribed by the tribal policies of DOE and BPA and fully complying with applicable laws and regulations.

Issue 5

Whether BPA's use of the words "in consultation with" in the Federal Register Notice when describing the discussions that occurred during the development of the Principles with a number of parties in the Northwest, including the Columbia Basin Tribes, was inaccurate and misleading.

Parties' Positions

CRITFC/Yakama and Shoshone-Bannock Tribes argue that, notwithstanding the statement in the Federal Register Notice, the Principles were not developed "in consultation" with the Columbia Basin Tribes as the tribes define the term "in consultation." Lothrop, WP-02-E-CR/YA-02, at 7; Kutchins, WP-02-E-SH-01, at 5. Based on a definition of consultation developed by the Confederated Tribes of the Umatilla Reservation, the process described by BPA was clearly not consultation with the tribes. Lothrop, WP-02-E-CR/YA-02, at 7; CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 54.

CRITFC/Yakama also argue that "[l]etters from a number of Columbia Basin Tribes reinforce the conclusion that these Fish [and Wildlife] Funding Principles do not have the support of the tribes . . ." *Id.*

BPA's Position

BPA's informal usage of "consultation" in this context refers to the public process of sharing and gathering of information among the voluntary participants listed above. DeWolf *et al.*, WP-02-E-BPA-39, at Attachment 3. Also as used in this context, consultation does not necessarily mean that consensus was reached among the participants, but rather that everyone had a chance to participate and voice their opinions, suggestions, and concerns during the development of the Principles. *Id.*

Evaluation of Positions

The passage in the Federal Register Notice to which the parties refer states:

> The Principles were developed *in consultation with constituents, customers, other Federal agencies, the Northwest Congressional delegation, and Columbia Basin Tribes* in an extensive public involvement process. The parties focused on guidelines for structuring BPA's approach to Subscription and FY 2002-2006 power rates to ensure that BPA could meet its financial obligations, including

> those for fish and wildlife, given hydroconditions, market prices, fish recovery costs, and other uncertainties.

64 Fed. Reg. 44318, 44321 (1999). (Emphasis added.)

Shoshone-Bannock Tribes also argue that they do not consider consultation to be a public process, but instead a formal process of negotiation, cooperation, and policy-level decisionmaking between sovereigns. Kutchins, WP-02-E-SH-01, at 5. BPA explained that it did not intend to use the strict definition of "consultation" as that term is defined in BPA's Tribal Policy, but rather a more general definition, since BPA was seeking input from many parties in addition to the tribes. DeWolf *et al.*, WP-02-E-BPA-39, at 34. BPA also expressed regret for any confusion that its use of the word "consultation" may have caused. *Id.*

Despite BPA's explanation in its rebuttal testimony, CRITFC/Yakama raised this issue again in its brief. CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 54. BPA acknowledges that the use of the word "consultation" may have caused some confusion on the part of the tribes. However, BPA's use of the word "consultation" was meant to encompass many interested participants and was not in any way structured as a formal consultation and decisionmaking process among sovereigns. BPA's purpose for including the sentence at issue here was to provide readers with a sense of how expansive and inclusive the public process was that resulted in the Principles. This public process was not structured as a formal consultation and decisionmaking process among sovereigns, and BPA did not intend to convey that BPA engaged in a formal consultation and decisionmaking process with the Indian tribes.

Decision

BPA's use of the words "in consultation with" in the Federal Register Notice passage describing the public process involved in the development of the Principles caused some confusion, and BPA regrets any offense it may have caused. Notwithstanding any such confusion, BPA participated in the development of the Principles with the involvement of a great many participants with diverse interests. BPA does not believe, nor did it represent, that this public process was a formal consultation and decisionmaking process among sovereigns.

18.2.3 Adequacy of Briefing Schedule

Issue

Whether parties were afforded sufficient time to prepare their briefs on exceptions.

Parties' Positions

The IOUs maintain that they were given insufficient time to prepare their brief on exceptions, in violation of statutory and due process rights. IOU Ex. Brief, WP-02-R-AC/GE/PI/MP/PL/PS/EN-01, at 78.

BPA's Position

BPA has had no prior opportunity to express an opinion with regard to this issue.

Evaluation of Positions

The IOUs' position is without merit. Fourteen (14) days was adequate time to prepare their brief on exceptions. There are always competing demands of various kinds in any schedule. That is true for BPA as well as the parties. As to the complexity and length of the Draft ROD, that has more to do with issues raised by parties on their own initiative than it does with BPA's desire to author a voluminous Draft ROD. Every issue addressed therein was raised in some party's initial brief. Moreover, when BPA moved for an extension of time to prepare the Draft ROD, BPA requested that the parties be permitted additional time to prepare their briefs on exceptions. That additional time was requested by BPA in the interest of fairness. The Hearing Officer's Order states: "In extending the date for the Draft ROD, BPA also extends additional time to the parties to prepare their briefs on exceptions." WP-02-O-22. Furthermore, "[n]o party filed an objection to the extension, and good cause is shown for granting BPA's request." *Id*. After issuance of the Draft ROD, there was absolutely no reason why the IOUs could not have requested relief from the Hearing Officer by motion. Because they did not do so, the argument is waived.

Decision

The IOUs and other parties had adequate time to file briefs on exceptions, and there was no denial of due process or statutory rights.

18.3 Environmental Analysis

18.3.1 Introduction

BPA's 2002 power rate design is influenced by four policy considerations. First, BPA is voluntarily complying with FERC Order Nos. 888 and 889 by unbundling its transmission and ancillary services from its wholesale power services. Second, west coast market conditions have changed since the 1996 power rates were designed. Third, BPA's rate design is guided by the Principles established on September 21, 1998. *See* ROD sections 2.3, 5.4, and 18.2.2. Fourth, BPA's power rates are designed to implement the decisions in the Power Subscription Strategy. Burns and Elizalde, WP-02-E-BPA-08, at 1-9. *See* ROD sections 2.1 and 18.2.1.

The 2002 power rates include many features that will help BPA achieve the goals of the Subscription Strategy. These include:

- Continuing stable PF rates as established in the 1996 rate proceeding.

- Establishing rates for IOU Subscription sales at a rate as close as possible to the PF rate for sales under sections 5(b) and 5(c) of the Northwest Power Act.

- Establishing three-year and a five-year fixed PF rates and a five-year stepped rate.

- Establishing a TAC for PF and NR loads placed on BPA after the close of the Subscription window.

- Establishing an IPTAC.

- Establishing a CRAC.

- Developing a DDC to provide for return of excess financial reserves.

- Establishing monthly energy and demand charges.

- Establishing cost-based indexed PF and IP rate options.

- Developing rate mitigation in the form of cap for the Demand and Load Variance charges, an LDD, and relief for customers with large amounts of irrigation loads.

- Resolving certain inter-business line costs.

- Resolving treatment of GTA costs.

- Deciding to augment the system to serve more load than was anticipated by the Subscription Strategy.

- Establishing a C&R Discount to requirements rates.

- Establishing a GEP to allow a customer to designate a percentage of its Subscription purchase as EPP.

Burns and Elizalde, WP-02-E-BPA-08, at 9-21.

BPA's final 2002 power rate proposal is consistent with the Power Subscription Strategy and Power Subscription Strategy ROD (December 21, 1998), BPA's Business Plan, the BP FEIS (DOE/EIS-0183, June 1995), and the Business Plan ROD (August 15, 1995). The BP FEIS and ROD were intended to guide BPA in a series of related decisions on various issues and actions. Before taking specific action on any of these issues, BPA stated that the Administrator would review the BP FEIS to ensure that a particular action was adequately covered within the scope of that BP FEIS and, if appropriate, issue a tiered ROD. Tiering subsequent RODs to the Business Plan ROD is helping BPA delineate decisions clearly, and provides a logical framework for connecting broad programmatic decisions to more specific actions. BPA's 2002 power rate proposal falls within the scope of the BP FEIS.

Consistent with the Business Plan ROD, the Administrator reviewed the BP FEIS to determine whether the actions embodied in establishing the 2002 power rates were adequately covered within the scope of the BP FEIS. The analysis in the BP FEIS includes an evaluation of the environmental impacts of rate design issues for BPA's power products and services. Comments on the Business Plan EIS were received outside the formal rate hearing process, but are included in the rate case record and considered by the Administrator in making a final decision establishing BPA's 2002 power rates. The following section summarizes and incorporates information from the Business Plan and the BP FEIS.

18.3.2 National Environmental Policy Act Analysis

The BP FEIS evaluates six business policy direction alternatives: Status Quo (no action); BPA Influence; Market-Driven; Maximize Financial Returns; Minimal BPA; and Short-Term Marketing. In the Business Plan ROD, the BPA Administrator selected the Market-Driven alternative. Each of the six alternatives provided policy direction for deciding major policy issues in broad categories; variations of the alternatives (modules) were developed for four key issues, including rate design.

The alternatives examined in the BP EIS were evaluated against the need for and purposes of the action. The wholesale electricity market is increasingly competitive. To be able to compete in the changing utility market, BPA needs an adaptive policy, which will allow the agency to meet its public service and business missions. The 19 key policy issues analyzed include several rate-related decisions, such as unbundling or rebundling BPA's power products and services and pricing. The modules included a range of rate level and design alternatives. Alternatives for rates analyzed in the BP FEIS include tiered rates, streamflow-based rates, seasonal rates, surcharges, market-based pricing, and elimination of existing rate discounts.

The BP EIS found that environmental impacts are determined by the responses to BPA's marketing actions, rather than by the actions themselves. *See* BP FEIS, page 4.1. The BP FEIS identified four types of market responses: resource development; resource operations; transmission development and operation; and consumer behavior. These market responses determine the environmental impacts. The environmental impacts addressed in the BP FEIS include those related to the physical environment, including air quality, water quality, land use, human health, and safety. They also include those related to the socio-economic environment, such as the effects of changes in products, services, and rates on end-users (consumers) of electricity, including BPA's DSI customers.

General market responses to the 19 key policy issues are shown in Table 4.2-1 of the BP FEIS. The market responses for products and services are discussed for each of the alternative business directions in section 4.2.1 of the BP FEIS, and the market responses for rates are discussed in section 4.2.2 of the BP FEIS. The environmental consequences for the market responses are evaluated in section 4.3 of the BP FEIS. Section 4.4 presents the market responses and environmental impacts by alternative. The market responses and environmental consequences for the range of power rate design alternatives in the rates module are discussed in section 4.5.2 of the BP FEIS. In addition, Appendix B to the BP FEIS includes an exhaustive evaluation, including market response and environmental impacts, of a range of power rate types, attributes, and adjustments. Specifically, Tables B-3 and B-4 in appendix B (Rate Design) of the BP FEIS summarize loads and resource responses for the range of rate alternatives examined.

Additional information on the environmental consequences of the six alternative plans of action is presented in sections 4.3 and 4.4 of the BP FEIS. The potential environmental impacts of all alternatives fell within a fairly narrow band, and several of the key impacts are virtually identical across alternatives. In addition, the costs of environmental externalities differ only slightly between alternatives. (Table 4.4-20, BP FEIS.) Business Plan ROD, at 6.

In the Business Plan ROD, the Administrator chose the Market-Driven alternative. The Market-Driven alternative strikes a balance between marketing and environmental concerns. It also helps BPA to ensure the financial strength necessary to maintain a high level of support for public service benefits such as energy conservation and fish and wildlife mitigation activities. The BP FEIS and Business Plan ROD also documented a decision strategy for tiering subsequent business decisions to the Market-Driven approach (BP FEIS, section 1.4.2; Business Plan ROD, at 15). BPA's power Subscription Strategy was one of those subsequent decisions.

In deciding to establish the 2002 power rates as a feature of implementing the Market-Driven approach, BPA understands that the conditions that permit the agency to function successfully may change over time. Therefore, the Market-Driven alternative contains preparatory mitigation measures (response strategies) to respond to change and allow the agency to balance costs and revenues. Such mitigation will enhance BPA's ability to adapt to changing market conditions. These response strategies--which include means to decrease spending, increase revenues, and transfer costs--could be implemented if BPA's costs and revenues do not balance. BPA decided in the Business Plan ROD to apply as many mitigation response strategies as necessary whenever BPA's costs and revenues do not balance. These mitigation strategies, or equivalents, will be implemented to enable BPA to best meet its financial, public service, and environmental obligations, while remaining competitive in the wholesale electric power market.

18.4 Participant Comments

18.4.1 Introduction

This section summarizes and evaluates the comments of participants in BPA's 2002 rate proceeding. Participants are persons and organizations who comment on BPA's rate proposal by means of attendance at field hearings, correspondence, or phone calls but do not take part in the formal rate case hearings. Comments of participants are part of the official record of the rate proceeding and are considered when the Administrator makes her decisions set forth in this ROD.

The participants' portion of the Official Record consists of transcripts of nine field hearings held in September, October, and November 1999, throughout the region. A total of 174 persons presented comments at the field hearings. The field hearings were transcribed, and the transcripts were made part of the Official Record. BPA also received over 7,000 pieces of correspondence and documented telephone calls related to the rate filing during the public comment period, which officially ended November 30, 1999. These comments also are part of the Official Record. Over 700 additional pieces of correspondence were received after the conclusion of the official public comment period.

BPA reviewed the participants' portion of the record and identified the concerns expressed by the participants to be addressed in this chapter of the ROD. Comments on technical areas addressed by the parties are evaluated in the foregoing ROD chapters that address those topics.

Following is a tally and summary of the testimony provided at the field hearings and the letters and telephone calls that BPA received both during and after the comment period, along with discussions of those concerns.

Copies of the comments of participants and letters received after the comment period will be available for inspection in BPA's Public Information Center by the time this final ROD is issued.

18.4.2 Evaluation of Participant Comments

The summary indicates the total responses for each issue; many letters contained more than one comment. Over 6,400 comments from letters and over 700 comments from the field hearings were analyzed.

Rate Case Process	Field Hearings Comments	Letters Comments
a. BPA already has made up its mind; BPA ignores our concerns.	4	5
b. Afraid the "Good Old Boy" network will make decisions.	1	
c. Issues are not clearly stated; there is misinformation or missing information or lack of advertising; need more information.	8	29
d. More hearings in different locations (*e.g.*, Goldendale)	2	3
e. Continue dialogue with local citizens and tribes about different subjects (*e.g.*, fish, economic development, DSIs)	9	
f. It is too expensive to participate.	1	1
g. Thanks for a good process and past programs and cost cutting.	6	
h. Do not deny people a voice in the process.	4	2
i. Timing of the rate case is wrong (*e.g.*, important decisions about dams on the Snake River yet to be made)	4	1
j. Theft, corruption, malfeasance, incompetence, intentionally misleading statements, or other ethical, legal, or practical concerns related to the rate increase and/or process.		49
k. BPA acting in or responding to a partisan (liberal or conservative, Democratic or Republican, socialist or capitalist, environmentalist or industrialist) manner.		8

Discussion

Several commentors stated that BPA made up its mind early in the process and ignored the concerns of parties and participants. Another expressed concern that the "good old boy" network will make the decisions. Several accused BPA of acting in a partisan manner or responding to a partisan position. Several stated that BPA should not deny people a voice in the process. Commentors stated concerns with ethical, legal, or practical matters related to the rate proposal and process.

BPA has been holding various public involvement processes for several years to develop information to feed into the 2002 power rate case. For example, BPA conducted a public process to develop the Power Subscription Strategy, and the decisions from that process appeared in the Power Subscription Strategy Administrator's ROD published in December 1998. BPA also has been conducting public processes to receive information in aid of developing the C&R Discount, to design the Slice product, and to evaluate the proposed Good Corporate Citizenship Clause. Once BPA knows it needs to adjust its rates, it develops its rate proposal in a multiphase process. Prerate case workshops began in April 1998. These workshops generally are highly technical. Notice is posted on BPA's Internet site and mailed to interested persons. BPA staff and others revise computer models, conduct analyses, and develop alternative solutions and share them in the workshops. For the rate case itself, BPA follows the procedures outlined in section 7(i) of the Northwest Power Act. BPA has added steps to those procedures to make the rate case even more informative. Rate cases include many chances for the parties to read and ask questions about BPA's case and to provide comments and criticisms to BPA. One of those chances occurred March 2, 2000, when the parties presented their oral arguments directly to the Administrator and other top BPA officials. Rate cases also include a public comment period, during which BPA holds field hearings around the region and accepts comments submitted by post, electronic mail, or telephone. Other than officially recognized parties, any person or organization may comment and thus become a participant. BPA received several thousand participant comments this year, and each was cataloged, read, and considered before the Administrator made her decisions summarized in this ROD.

Commentors stated that issues are not clearly stated and information is insufficient. Comments were concerned about misinformation, missing information, and lack of advertising. Two commentors stated that it is too expensive to participate. BPA understands the frustration that can occur when dealing with a large entity such as BPA. We have tried to make information complete, accurate, and available through various sources, such as the Internet (www.bpa.gov), mailing lists of interested persons, advertisements in local newspapers, and a toll-free line to BPA's public information and document request center (1-800-622-4520). BPA also publishes a comprehensive monthly newsletter called the Journal to which anyone may subscribe free by calling BPA's toll-free line. BPA will mail information to those who request it, free of charge. It is expensive to become an official party to the rate case, and such a responsibility requires time and expertise. The Hearing Officer admits to party status any group that can fulfill its responsibilities and does not represent an interest already represented by another party. But as stated earlier, anyone not representing an official party can become a participant and have his or her comments included in the official record of the rate proceeding.

Several commentors stated that the timing of the 2002 power rate case is wrong, considering that the decision whether to breach the Snake River Dams is yet to be made. BPA recognizes that the decision whether to breach is an important one that could influence power rates for many years. Other issues regarding BPA's fish and wildlife obligations also are pending. The available options have different costs associated with them, so BPA's tools for assessing financial risk include methods to ensure that BPA's rates will recover sufficient funds to meet the costs. These methods are included in the rates and will provide mitigation should future revenues not be as high as expected. *See* ROD chapters 6 and 7. The Subscription Strategy published in December 1998 developed a framework for contract prototype development for power sales contracts to be put in place in 2001. Current power sales contracts expire in 2001 and need to be replaced. BPA needed to conduct the 2002 power rate case early enough to have final rates available when individual contract negotiations get underway for Subscription sales.

Several commentors stated that BPA should hold field hearings in various different locations. In setting up the field hearings, BPA must find a large facility that will accommodate a large crowd, and such facilities are available in only some of the cities in the region. Another consideration is geography – BPA schedules field hearings in areas that are representative of the large variation in economy that the region supports so as to receive a broad range of opinions. Cost limits the number of hearings. In the 2002 power rate case BPA held nine field hearings around the region, during September, October, and November 1999. Advertisements were placed in local newspapers and notice was posted on the rate case Internet site and mailed to interested persons. The hearings were well attended and provided useful information to BPA in developing its final 2002 power rate proposal.

Several commentors thanked BPA for a good rate process and past programs and cost cutting. Several commentors stated that BPA should continue dialogue with local citizens and tribes. BPA appreciates the positive feedback and will continue working to become more business-like. BPA will continue dialogue with local citizens and tribes whenever possible. Anyone may keep up-to-date on issues, meetings, and chances to comment by looking at BPA's Internet site or by subscribing to the Journal.

General Rates Issues		Field Hearings Comments	Letters Comments
a.	Oppose rate increase.	4	20
b.	Hard to pay rates on a fixed/low-income, includes senior citizens, disabled, and retired citizens.	4	410
c.	Taxes too high/cost of living too high/all or other utilities too high; Energy Northwest made rates too high.	1	59
d.	BPA should keep a balanced view of meeting the concerns about the future with the needs of today.	1	1
e.	No choice in selecting utility provider; do not penalize because of location or residence.	1	29
f.	Public power works.	3	0
g.	A longer-term solution is needed to competitive public/private issues. Public preference keeps competitive market forces from benefiting all electric customers.		1
h.	Favor rate increase (*e.g.,* spend money on fish, to meet Treasury payment, etc.)	4	1
i.	Power generation has been subsidized by the loss of fish and wildlife.	1	1
j.	Mergers, monopolies, lack of concern for people, shortsighted, everything slanted in their favor, greed.		23
k.	Electricity is a public necessity; profit should be secondary.	1	1

General Rates Issues		Field Hearings Comments	Letters Comments
l.	Provide the residential, business and small customers of IOUs a fair and equitable share of the Northwest's Federal power.	5	9
m.	Prioritize power for Northwest benefit (including comments about specific states, WA for example), as long as it is needed here.	9	46
n.	Power should be offered to customers in the Northwest before it is sold out of the region for profit at market rates, offer it at cost to NW customers.	3	
o.	Power should not be sold outside the region when there are regional customers that are willing to purchase at cost. The DSIs should be considered as one of those alternatives.	5	
p.	Continue the benefits of hydropower to everyone in the region.	3	64
q.	Do not have disproportionate rate increases for different customer classes.	8	5
r.	Against tax breaks and subsidies for utilities (includes PUDs, DSIs).	6	4
s.	We are losing jobs in this nation. We are crippling our own country by continuing to take away from our own industries by putting pressure on them. We will force them to go elsewhere. We want to retain our businesses and attract new ones.	23	2
t.	If lost revenues are to be counted as a cost, do not just count spill; count water through the locks for navigation, water siphoned off for crops in Idaho, pumping, etc. BPA is shifting around the costs.	1	
u.	Electric supply and costs are a major factor of many of our customers.	6	1
v.	The economy is only good for corporations, BPA and PUDs; profit-oriented corporate leaders have plundered the Northwest.	7	
w.	Our farmers, especially dairy farmers, need and deserve the credit for the service they do for the country. Family farms going under. Farms need cost-based power.	5	4
x.	BPA should consider the economic impacts of its rates; those impacts affect jobs, families, and security.	15	7
y.	The aluminum companies provide excellent paying jobs, contribute to the tax base, and provide secondary benefits to their communities.	17	7
z.	Agricultural provides jobs and income and provides secondary benefits to their communities.	2	

General Rates Issues	Field Hearings Comments	Letters Comments
aa. The taxpayers did not pay for BPA; they paid for the money to start BPA. But the ratepayers have paid for BPA.	1	
bb. BPA as a government agency represents the people, not the companies.	1	11
cc. BPA should not compete with private enterprise.		89
dd. BPA's mission is to provide rural electrification, including obligations to the agricultural sector.	12	2
ee. The issue is the cost and availability of power to BPA's historical and industrial customers.	1	1
ff. Citizens expect BPA to be managed efficiently.		6
gg. The public is concerned about the decisions that BPA makes, and the effect they will have on the future.	1	1
hh. Transportation costs.	1	

Discussion

Many participants commented on the level of BPA rates, stating they want no rate increase and that any increase would be hard to absorb on a fixed income or with the slim profit margins of farmers. BPA understands these concerns. In the initial proposal, BPA successfully met its rate pledge of no increase in the PF Preference rate from 1996 rate levels. The RL-02 rate for IOUs that participate in a settlement of the residential exchange is equal to the PF Preference rate, and those benefits will be passed through to residential and small farm consumers of IOUs that choose to participate in a settlement. The PF Exchange Program rate, for IOU customers that continue to participate in the traditional residential and small farm power exchange, is higher than the PF Preference rate. This is because of the "triggering" of the 7(b)(2) rate test, which protects the rates of Preference customers as described in section 7(b)(2) of the Northwest Power Act. Assuming that a utility participating in the exchange program has an ASC higher than BPA's PF Exchange rate, then that utility will receive benefits that will be passed on to residential and small farm consumers. BPA's ratesetting methods and the Subscription Strategy assure that the residential and small farm consumers of IOUs receive the benefits they are entitled to under law.

Some commentors stated concerns with the difference between publicly owned and privately owned utilities regarding rate levels to consumers and the difference in rates BPA charges these types of utilities. BPA understands this concern. In setting the 2002 power rates, BPA has complied with several Federal laws, implemented the Subscription Strategy, and forecasted future needs for financial reserves, risk management strategies, and other expenses. This required a fine balancing of past, present, and future customer needs and responding to other concerns such as fish and wildlife restoration and promotion of conservation and renewable resources. BPA believes its final 2002 power rate proposal has successfully balanced the requirements and concerns within the many and varied constraints to which BPA is subject. Some comments addressed the greed of privately owned businesses, and tax breaks and subsidies for businesses; these issues are outside the scope of the rate case. BPA sells wholesale power and pays its expenses as directed by its statutory authorities and is not able to comment upon issues of fairness in other businesses. *See also* the Residential Exchange discussion in this ROD chapter.

Commentors stated concerns with the health of various economic sectors, including agriculture and industry. One comment stated that BPA's mission is to provide rural electrification, including obligations to the agricultural sector. Two comments were concerned about the cost and availability of power to BPA's historical and industrial customers. BPA realizes the importance of keeping jobs in the region and using the relatively inexpensive output of the FCRPS to benefit the regional economy. BPA also is aware that the cost of electricity can be a large component of manufacturing and farming expenses. The 2002 power rates include several features to encourage regional businesses. One of the DSI rates, the cost-based indexed IP rate, is tied to the price of aluminum, allowing the aluminum smelters' price of power to decrease as the price of their product decreases, and vice versa. That rate is designed to recover on average the costs allocated to the DSIs. *See* ROD chapter 15 for a further discussion of DSI rate issues, and section 10.16.2 for a discussion of the cost-based indexed IP rate. BPA is continuing the LDD, is capping the Demand Charge and the Load Variance Charge, and is setting aside $4 million for relief for customers with a high proportion of irrigation loads. The foregoing list of rate impact mitigation measures is implemented in BPA's wholesale rates; how the local utility passes to consumers those benefits is not within BPA's control.

Many commentors stated that BPA should assure that FCRPS power is used to benefit the PNW region before selling the power outside the region. This BPA does as a matter of course, to comply with the Regional Preference Act, P.L. 88-552, and the Subscription Strategy. The Subscription Strategy ROD states: "Sales to extraregional entities are a possibility only if BPA does not subscribe all of its Federal power to Pacific Northwest customers. Such sales are not the focus of the Subscription process, but BPA intends that any power remaining after all requests from regional loads are met will be offered to extraregional public customers consistent with public preference and other customers under the applicable provisions of Northwest preference statutes." Subscription Strategy ROD, at 71.

Several commentors favor a rate increase, in particular to increase spending for fish and wildlife restoration and conservation and renewable resources, and to build up financial reserves for the same programs. As mentioned above, setting BPA's rates is a fine balancing act. BPA believes its final 2002 power rate proposal has successfully balanced the requirements and concerns within the many and varied constraints to which BPA is subject. *See* ROD chapters 5 and 7 for a discussion of financial issues.

One commentor stated that if BPA is going to count lost revenues from spill as a cost, BPA should include in its revenue requirement the cost of water passed through the locks due to navigation, water siphoned off for crops, and so on. BPA's governing statutes instruct BPA to set rates for the power it markets, based on the costs of that power, not based on the cost of water used for purposes other than power generation. BPA includes the cost of fish and wildlife programs, including spill, in its revenue requirement because those costs are directly attributable to operation of the Federal hydrosystem. Costs for water used for navigation and farming are not directly attributable to marketing power, nor could they easily be quantified even if they were relevant costs.

One commentor stated that the taxpayers do not pay for BPA; ratepayers have paid for BPA. This is true. BPA does not receive Congressional appropriations but depends on funding from rates charged for sales of power and transmission products and services. Several comments stated that BPA as a governmental agency represents the people, not the companies. Several comments stated that citizens expect BPA to be managed efficiently. One comment stated that the public is concerned about the decisions that BPA makes and the effect they will have on the future. Many comments stated that BPA should not compete with private enterprise. How BPA does business is determined largely by its governing statutes, including the Regional Preference Act, P.L. 88-552, and the Northwest Power Act. For example, how BPA markets power to customer groups (utilities, DSIs, and others) is defined in section 5 of the Northwest Power Act. How BPA sets its rates is defined in section 7 of the Northwest Power Act. BPA also does business consistent with policies it sets itself, such as the Power Subscription Strategy. Such policies are developed with the help of extensive public involvement processes that allow BPA's customers, constituents, and others to state their opinions and present alternative analyses if they choose. The BPA Administrator makes decisions to establish policies and set rates only after considering all the comments in the official record of the proceeding. BPA has been reducing staff for several years and streamlining its processes as much as possible so as to become more business-like, efficient, and competitive.

Other General Issues	Field Hearings Comments	Letters Comments
a. New customers will not benefit from proposed transmission budget.	1	1
b. Want BPA in the Northwest to protect Northwest resources.	3	
c. It will cost more to shutdown WNP-2 than it would get in revenues for the next 10 years.	1	
d. WNP-2 operates above market rates. It will not cost too much to shutdown WNP-2.	1	
e. We have only one land, one water system and one air system. We all have to share it. So we all must work together and do our part to protect the environment and improve it when we have the chance.	2	
f. Coal-fired generators may move to the area. No one wants to breathe dirty air.	1	
g. Many of our residential customers think their electric bills are going to increase with energy deregulation.	1	1
h. The Northwest Power Act mandates conservation, prioritizing clean energy over nuclear, coal, and other fossil fuels.	11	7
i. Privatize BPA.		1
j. All utilities should be controlled by the Government and non-profit organizations.		1

Other General Issues	Field Hearings Comments	Letters Comments
k. Likes their utility.	3	
l. Does not like own utility.	2	5
m. Global warming issues (*e.g.*, Kyoto Accord).	2	1
n. Subscription issues (*e.g.*, plan not fair or equitable, need flexible products, expand involvement of other utilities, abandon plan).	6	3
o. Other	3	9

Discussion

Other participant comments focused on issues outside of BPA's purview and outside the scope of the power rate case. These issues include competitive market forces, deregulation of the electric utility industry, public preference, and regional preference. BPA has no control over these issues but has set the 2002 power rates to respond to them, as discussed elsewhere in this section and elsewhere in the ROD. One comment stated support for Oregon Governor Kitzhaber's regional proposal. Another addressed water rights. Another voiced opposition to being part of the national power grid. Another stated that residential customers think their electric bills are going to increase with energy deregulation. These issues all are outside the scope of the rate case and BPA will not address them here.

Two comments stated that new customers will not benefit from the proposed transmission budget. Transmission financial requirements are outside the scope of the 2002 power rate case. The few transmission-related issues addressed in the 2002 power rate case may be found in ROD chapters 8 and 9.

One comment stated that WNP-2 should be shut down because it operates at above market rates. This issue is outside the scope of the power rate case.

Several comments addressed the benefits of preserving and improving the natural environment, including one comment addressing the Kyoto Accord. One comment stated that the Northwest Power Act mandates conservation, prioritizing clean energy over nuclear, coal, and other fossil fuels. BPA is proud to support conservation and renewable resources programs. How these programs are included in BPA's rates is addressed in ROD sections 10.13 and 10.14; the issue of spending levels for these programs is outside the scope of the rate case.

A few commentors stated that they like or dislike the electric utility that serves them. One stated that they are entitled to cheap power because power lines cross their property. One stated that they should be compensated for having to have lights on all night long because they do not have street lights. One commentor stated that all utilities should be controlled by the Government and non-profit organizations. The 2002 power rate case sets rates for BPA's wholesale power and does not address retail utility pass-through of the rates or other retail issues. These are outside the scope of the rate case.

Residential Exchange	Field Hearings Comments	Letters Comments
a. Form letter from We Care. All residential customers, whether they live in cities or rural areas, deserve the same opportunity to receive a fair share of Federal electricity cost savings. Develop a plan that treats all residential customers fairly.		4,859
b. Small co-ops could be hurt by giving out additional exchange benefits.	16	3
c. Rural residents as well as other residents are also customers of IOUs.	7	1
d. Do not change formula so that residents in rural areas receive less.	10	12
e. Do not give energy to IOUs with below BPA average system costs.	2	4
f. Support or expand the residential exchange.	5	4
g. Do not help the IOUs because they are responsible to investors not the customers.	6	2
h. Sell IOUs extra power but do not give them money.	2	
i. Do not support the Puget power grab.	7	2
j. BPA has shirked its obligations under the Northwest Power Planning Act.	1	3
k. Follow the laws pertinent to the allocation of power.	1	2

Discussion

Comments received on the REP were critical of BPA's implementation of the Power Subscription Strategy of December 1998. A major goal of that BPA policy and other BPA policies is to promote the spread of the benefits of the FCRPS as broadly as possible, especially to residential and small farm customers in the region. Comments received on the initial power rate proposal stated that BPA's proposal did not meet that goal.

A major concern of commentors was equity. Retail customers of IOUs, including many rural customers, stated that their exchange benefits should not be less than those of publicly owned utilities. On the other hand, other commentors stated that BPA should not provide any exchange benefits to IOUs, who seem to evidence more responsibility to their investors than to their customers. Other commentors stated that BPA should not be selling power to the DSIs, because doing so reduces exchange benefits to residential and small farm consumers. Others stated that BPA should follow the laws pertinent to the allocation of power.

The Subscription Strategy provided a marketing policy framework for the power rate case. After discussing the issues in an extensive public process, BPA stated in its Subscription Strategy and ROD that an IOU has the choice whether to continue to participate in the REP or enter into a settlement of the program. Under a settlement, BPA would offer a certain number of aMW worth of benefits for residential and small farm consumers at a rate expected to be approximately equal to the PF Preference rate. Because these decisions were made in a previous public involvement process and stated in a previous ROD (Power Subscription Strategy Administrator's ROD, December 1998), these decisions are not at issue in the 2002 power rate case, except for ratemaking implications of providing the IOUs an additional 100 aMW for the proposed settlement.

The 2002 power rate case implemented the Subscription Strategy by setting a rate for power purchased under the REP described in section 5(c) of the Northwest Power Act (PF Exchange rate). It also set rates for power purchased to meet IOUs' net requirements under section 5(b) of the Northwest Power Act, including: the NR-02 rate; and the RL-02 rate and the PF Exchange Subscription rate, which would be used to serve an IOU's residential and small farm load under a settlement. The 5(b) and 5(c) rates proposed in the 2002 rate case were designed to comply with the rate directives in the Northwest Power Act and the Subscription Strategy. The statutory directives include section 7(b)(2), which protects the rates of BPA's preference customers from certain costs of the Act and can result in the PF Exchange rates being higher than the PF Preference rate. The PF-02 Preference rate and the RL-02 rate are identical in level, although they serve different shapes of loads. The PF Exchange Program rate is higher than the PF Preference rate due to the 7(b)(2) rate test. An IOU has a choice as to how to provide the benefits of the FCRPS to its residential and small farm consumers, and thus the rate it will pay for BPA power. Utilities are required by law to pass the benefits of the exchange program through to their residential and small farm consumers; the exchange is not designed to benefit the utility itself. As discussed elsewhere in this ROD, BPA believes that in setting its 2002 power rates it has complied with the Subscription Strategy and all applicable laws, including section 5(c) of the Northwest Power Act, which defines the residential and small farm power exchange.

Similarly, BPA believes that its intent to serve a portion of DSI loads complies with the Subscription Strategy and all applicable laws and will not significantly reduce the exchange benefits of any residential and small farm customers.

Comments received stated that "huge" financial reserves reduce consumers' fair share of exchange benefits. As discussed elsewhere in this ROD, BPA's risk management tools, including financial reserves, balance the many needs BPA faces. BPA must consider its obligation to repay the U.S. Treasury for the Federal investment in the FCRPS; its competitive position in the market; its ratesetting and other requirements as set forth in its governing statutes; and future possibilities for contingencies and uses of funds. For detailed discussions of revenue requirements and risk, *see* ROD chapters 5, 6, and 7.

Tribal Issues	Field Hearings Comments	Letters Comments
a. BPA has Trust responsibility to the tribes, and to all of the people.	7	4
b. By building the dams, the Government ensured that the Northwest tribes would no longer be able to subsist on fishing.	1	
c. Tribes are seeking economic development and jobs and cultural resources, including fish and wildlife, protection.	4	2

Tribal Issues	Field Hearings Comments	Letters Comments
d. The Federal Government has not followed through on its promises to the tribes.	3	1
e. The current proposal creates a risk that BPA will fail to meet tribal obligations.	2	1
f. Tribes do not want to take jobs away from steelworkers.	1	
g. Labor leaders have an interest in the region's tribal obligations and environmental health.	2	

Discussion

Several comments addressed the U.S. Federal Government's trust and treaty responsibilities to the tribes. BPA takes these responsibilities seriously and in all its programs strives to fulfill its responsibilities. *See* ROD section 18.2.2, Issue 4. One comment referred to the Federal Government building the dams as a way to deprive the tribes of their livelihood and in turn their society; a couple of comments discussed the mutual respect between the tribes and steelworkers. These issues are outside the scope of the rate case.

Several comments summarized the goals of the tribes as being economic development, jobs, and protection of cultural resources and fish and wildlife. A couple of the comments imply that they favor wind power. BPA has several rate features that indirectly will protect jobs, including the cost-based indexed IP rate and the LDD. BPA also has successfully met its rate pledge to keep average PF rates at 1996 levels. Along with COE and Reclamation, BPA funds programs to preserve cultural resources that could be damaged by river operations, or by construction or O&M activities. The three agencies that operate the FCRPS work together with the tribes to identify, record, and protect cultural sites. *See* ROD section 18.2.2, Issue 3. BPA also funds fish and wildlife programs consistent with the Principles, as discussed in ROD section 5.3.2. BPA recovers the costs of fish and wildlife programs, cultural resources programs, and conservation and renewable resource programs through its rates, but spending levels are determined outside the rate case. The 2002 power rates also include a C&R Discount that is designed to encourage these alternative forms of energy production. *See* ROD section 10.13.

Low Density Discount	Field Hearings Comments	Letters Comments
a. This discount is outdated and has served its purpose and should be eliminated. The savings should be applied to lowering the PF-02 rates.		1
b. Isolated areas deserve a price break.		3

Discussion

Participants favor maintaining the LDD. The LDD is an active issue in the rate case. For a full discussion, *see* ROD section 10.12.

Risk Mitigation	Field Hearings Comments	Letters Comments
a. If BPA misses too many Treasury payments, then it will lose its special status (*e.g.*, cost-based rates).	1	
b. If BPA misses a Treasury payment, then it may not be able to fund fish and wildlife programs.	6	2
c. Raise rates to prevent missed Treasury payments and to pay for fish and wildlife costs.	1	
d. Do not calculate multiple deferrals as one deferral during the rate period.	2	2
e. BPA's risk is too high.	1	2
f. Does BPA need to sell power outside the region at higher rates to provide a cushion against current or future obligations?	1	1
g. Do not generate profit at expense of power customers.		2
h. Reserves will be spent on additional questionable programs.	4	
i. Reserve fund too high (*e.g.*, not standard business practice, places a tax on region, removes too much money from the economy for unknown or inappropriate reasons).	10	82
j. Reserve fund too low (*e.g.*, will not cover fish obligations and TPP, could increase rates substantially after this rate case).	9	7
k. Reserve fund adequate and appropriate.	1	2
l. Use part of the reserve to provide additional power or financial resources to constituents.		1
m. Unspent fish and wildlife funds are being used as part of the reserve.	1	
n. BPA treats all 13 alternatives as equally likely to happen in any given year. This is not the way we will proceed with salmon recovery in the Columbia Basin. The region will operate under a biological opinion until one path is chosen, and we will stay on that path for the remainder of the rate period. When viewed like this, TPP drops dramatically.	3	
o. Raise rates enough to cover all costs without the arbitrary cap proposed.	7	5
p. The DDC could have the effect of reducing future reserves and threaten future fish and wildlife restoration.	4	1
q. Do not give out the dividends and/or pay off the bonds.	2	1
r. The PNRR needs to be at least $180 million a year to be used as a contingency, if higher fish and wildlife costs are needed. In this rate proposal, that number has been reduced to $127 million a year.	2	1
s. New laws prevent good analysis of financial risks.	1	

Discussion

Two comments stated that BPA's risk is too high. Another stated that the rider Slade Gorton implemented to save the fish prevents good analysis of financial risks. Many of BPA's risks are out of its control, such as precipitation to "fuel" the hydrosystem and passage of new laws. BPA has conducted extensive risk analyses and included several risk mitigation measures in its 2002 power rates to address its risks. *See* ROD chapters 6 and 7 for a detailed discussion of risk.

Several commentors expressed concern about the negative effects of BPA missing Treasury payments. One comment suggested raising rates to assure Treasury payments and to pay for fish and wildlife costs. Several commentors instructed BPA not to count multiple deferrals as one deferral during the rate period. Issues regarding TPP are addressed in ROD section 7.2.

Several commentors stated that BPA's consideration of all 13 fish cost alternatives having equal chances of happening in any given year is not the way salmon recovery will occur in the Columbia Basin. Rather, the region will operate under a biological opinion until one path is chosen for the rest of the rate period. Comments claimed that TPP should be lower. Issues regarding the risk analysis are addressed in ROD chapter 6, and TPP is addressed in detail in ROD section 7.2.

Two comments asked whether BPA needs to sell power outside the region at higher rates to provide a cushion against current or future obligations. Two commentors stated that BPA should not generate profit at the expense of power customers. Several commentors stated that reserves will be spent on additional questionable programs. Many comments stated that BPA's reserve fund is too high. Others stated that BPA's reserve fund is too low and will not cover fish obligations or Treasury repayment, leading to higher rates in the future. A few commentors even stated that BPA's reserve fund is adequate and appropriate. One comment stated that part of the reserve should be used to provide additional power or financial resources to constituents. Issues regarding reserves are addressed in detail in ROD chapter 7.

Two comments stated that the planned net revenue for risk needs to be at least $180 million a year to be used as a contingency for higher fish and wildlife costs. In the 2002 initial proposal, that number was reduced to $127 million a year. Issues regarding PNRR are addressed in detail in ROD section 7.4.

Several commentors stated that BPA should raise rates enough to cover all costs without the arbitrary cap proposed. Commentors stated that the DDC could have the effect of reducing future reserves and threaten future fish and wildlife restoration. A few comments stated that BPA should not give out the dividends or pay off the bonds. Issues regarding the CRAC are addressed in ROD section 7.3, and issues on the DDC are addressed in ROD section 7.5.

Fish and Wildlife	Field Hearings Comments	Letters Comments
a. There are a lot of people that agree with the Native American position on costs, and fish costs, and dam breaching. There are going to be huge costs if the fish do not come back.	4	1
b. People are concerned about accounting for fish costs and making sure the monies spent assure the recovery of salmon and steelhead and resident fish.	8	6
c. The fish program and the science that has come from it needs to be analyzed to see if there are other alternatives.	7	
d. Support spending more money to meet fish and wildlife costs.	9	3
e. Against spending more money.	2	5
f. Consider impacts to other industries from preserving fish.		1
g. BPA should collect enough money now to pay for all biologically sound recovery measures.	10	1
h. Support BPA meeting its obligations for salmon recovery, but not at the expense of today's needs.	1	1
i. Ignoring salmon recovery will not make the issue go away.	1	2
j. Corporations must do their part to preserve fish.	1	
k. Suggestions for measures: fish friendly turbines, fish ladders, barging, flow augmentation, avoid nitrogen supersaturation, stop trolling, keep hatcheries, do not use nets, reduce or stop harvest, reduce sea lions, fish farming, restrict logging practices, do not club non-native fish, cattle, water temperatures, do not clip fins, spill, use nuclear power to protect fish and environment.	17	22
l. People are more important than fish.		3
m. The fish and wildlife MOA of 1995 says that unspent capital at the end of a year be dedicated to fish and wildlife costs. The rate proposal moves those unspent capital funds to the general reserves of the agency instead of dedicating them to fish and wildlife.	3	1
n. The fish and wildlife MOA of 1995 says that emergency credits under 4(h)(10)(c) can be expended to recover emergency situations such as a prolonged drought. Instead BPA's rate proposal sends $180 million of those emergency credits to sustain its rate proposal.	1	
o. Salmon recovery costs should be equally allocated to all users of area water.		4
p. I believe we can have both a vibrant agricultural economy and healthy salmon runs.	1	
q. Salmon and steelhead recovery will provide jobs and income and secondary benefits to communities.	1	

Fish and Wildlife	Field Hearings Comments	Letters Comments
r. Abolish or revise the Bolt Decision.		1
s. For dam breaching.	13	3
t. Against dam breaching.	11	6
u. Biological Opinion delay is illegal.	1	
v. Restore natural river conditions.	2	

Discussion

Many commentors stated opinions regarding whether dams should be breached to aid anadromous fish migration. Two comments recommended restoring natural river conditions. The 2002 power rates are designed to recover the costs of the fish and wildlife measures decided upon in the several separate public involvement processes currently underway to develop, analyze, and review various fish and wildlife initiatives.

Several comments stated that salmon recovery costs should be equally allocated to all users of area water. BPA's power rate development includes no mechanism to allocate costs to water users. BPA is required by law to allocate power costs to its customers as rates for purchases of power products and services.

One commentor stated that salmon and steelhead recovery will provide jobs, income, and secondary benefits to communities. Another stated that the region can have a healthy agricultural economy and healthy salmon runs. Another stated that corporations must do their part to preserve fish. BPA is proud to support fish and wildlife recovery programs. How these programs are included in BPA's rates is addressed in ROD chapters 2 and 5; the issue of spending levels for these programs is outside the scope of the rate case. Although BPA provides information to businesses and individuals regarding means to aid recovery of fish and wildlife, BPA is not authorized to require corporations to participate in or develop such programs.

Several commentors stated that many people agree with the tribes' positions on fish recovery and dam breaching, and that it is better to incur costs along the way than face a huge amount of costs in the future. Others said that they support BPA's "forward thinking" and current spending on fish and wildlife programs, but such should not come at the expense of today's needs. Others stated that BPA should collect enough money now to pay for all biologically sound recovery measures. Comments weighed in on both sides of the issue regarding whether to spend more money on fish and wildlife programs. BPA's 2002 power rate proceeding addressed implementation of the Principles developed in consultation with constituents, customers, other Federal agencies, the Northwest Congressional delegation, and the Columbia Basin Tribes. Actual spending levels will not be set until after the rate case is over, so the 2002 power rate levels must address a broad range of spending possibilities. *See* ROD section 5.4 for a detailed discussion of implementation of the Principles.

Two comments stated that ignoring salmon recovery will not make the issue go away. Several others stated that people are more important than fish. The public involvement process to develop the Principles considered these points of view and others before specifying guidelines for BPA's approach to Subscription and the 2002 power rates.

Commentors said that the fish program and the science behind it need to be analyzed to determine if there are alternatives. Several commentors stated that the money spent on programs should assure the recovery of salmon, steelhead, and resident fish, and BPA should be accountable for their success. BPA's fish and wildlife programs do incorporate analysis of alternatives, monitoring, and efficacy, but these analyses and BPA's accountability are not at issue in this rate case. Many commentors suggested measures to protect fish: fish friendly turbines, fish ladders, barging, flow augmentation, avoid nitrogen supersaturation, stop trolling, keep hatcheries, do not use nets, reduce or stop harvest, reduce sea lions, fish farming, restrict logging practices, do not club non-native fish, cattle, water temperatures, do not clip fins, spill, use nuclear power to protect fish and environment. BPA is pleased to see that so many people in the region have creative solutions to fish and wildlife recovery. BPA is implementing cost-effective measures that can be shown to be successful.

Several comments were received on the directives of the 1995 MOA signed by five Federal agencies to stabilize BPA's funding for fish and wildlife through 2001. (The 1998 Principles were developed to guide BPA's approach to Subscription and FY 2002-2006 power rates.) One comment stated that the 2002 rates improperly moved unspent capital funds to BPA's general reserves instead of dedicating them to fish and wildlife programs as directed by the MOA. Another stated that the 2002 rates improperly include $180 million of emergency credits under Northwest Power Act section 4(h)(10)(C). Another comment stated that $180 million of unspent, budgeted fish and wildlife funds are being used as part of BPA's reserves. *See* ROD section 5.4 for a detailed discussion of these issues.

One comment stated that the delay of the biological opinion is illegal. Another stated that the Bolt Decision should be revised or abolished. These issues are outside the scope of the 2002 power rate case and will not be addressed here.

Direct Service Industries	Field Hearings Comments	Letters Comments
a. DSIs are an integral part of the hydrosystem and BPA's Northwest power system (*e.g.*, using power at night).	5	
b. Give the DSIs a good rate and/or adequate supply of cost-based power.	28	14
c. Do not subsidize the DSIs.	23	67
d. Buying power for the DSIs will make my rates go up.	1	
e. DSIs should not be allowed to walk away from their share of the Energy Northwest debt.	5	5
f. Sell the aluminum industry secondary energy and let plants shift part of their load to the local utility.		1
g. Encourage the DSIs to conserve and/or buy clean electricity elsewhere; or clean up emissions.	5	1
h. DSIs should remain loyal to BPA and make that commitment.	1	

Direct Service Industries	Field Hearings Comments	Letters Comments
i. The DSIs have spent money to conserve power.	6	
j. System augmentation for the DSIs should come from energy conservation, wind, solar, geothermal power, or fish friendly turbines.	5	2
k. Support the augmentation plan.	1	
l. Encourage economical new generation to bring purchase power to zero.	1	
m. Supports flexible/variable rate.	6	
n. Supports take-or-pay option.	1	
o. Provide the DSIs with decent transmission rates if they install their own generation facilities to help with the shortage of power allocation by BPA.	1	
p. Aluminum is a reusable resource; keep plants here where we have environmental controls.	2	
q. Supports Insertion of the Good Corporate Citizenship Clause (Good employee relations; Environmental Stewardship; Community Relations and Workplace Safety).	73	26
r. Reject the adoption of a Good Corporate Citizen Clause.		6
s. Corporations will only comply with environmental regulations if the Clause is in their contracts.	2	
t. Petitions supporting Clause.		14,252
u. BPA has no legal obligation to serve the aluminum industry and other DSIs.		3
v. BPA is trying to make the aluminum companies go away and does not know the consequences of this.	4	
w. Part of the contracts process (*e.g.*, allocation of power to a company, not an aluminum plant).	6	2
x. Labor strike.	2	1

Discussion

Two commentors stated that aluminum is a reusable resource, and the plants should be kept in the Northwest where there are environmental controls. Several stated that the DSIs are an integral part of the Northwest power system. Many commentors stated that BPA should give the DSIs a good rate and adequate supply of cost-based power. Several commentors stated that BPA is trying to make the aluminum companies go away without understanding the consequences. BPA is concerned about the survivability of the aluminum smelters. These businesses support the local and regional (as well as national) economy and provide jobs whose wages can support families. They also are good customers for BPA, traditionally providing stable, 24-hour a day base loads. In the 2002 power rate case, BPA set the rates for the DSIs (the IP rate plus the IPTAC amounts) at levels substantially below market rates to help the DSIs survive. The IP rate levels were set in the initial power rate proposal to implement the Compromise Approach, which was developed in talks between BPA and the DSIs. The amount of power BPA will provide to meet DSI loads also is a product of the Compromise Approach. To aid aluminum smelter DSIs, BPA has developed a cost-based indexed IP rate that will vary with the price of aluminum. The cost-based indexed IP rate will help the smelters that choose to buy at that rate stay in business when the price of their product is low. Several commentors voiced support for the cost-based indexed IP rate. One commentor stated support for the contracts being take or pay.

One commentor pointed out that BPA has no legal obligation to serve the DSIs. Many commentors stated that BPA should not subsidize the DSIs. One commentor was concerned that buying power for the DSIs would increase his/her electric rates. Several commentors were concerned that the DSIs might not be paying their fair share of the debt for the Energy Northwest nuclear plants. Although BPA has no legal obligation to offer new requirements contract to serve the DSIs, BPA is authorized by the Northwest Power Act to sell to DSIs existing at the time the Northwest Power Act was passed. The 2002 IP rates are set to recover the costs of serving the DSIs, and thus BPA is not subsidizing the DSIs. Within statutory constraints and consistent with the Subscription Strategy and the Compromise Approach, BPA was able to develop cost-based rates that are low enough to encourage DSIs to stay in the region and maintain jobs, and high enough to recover the costs allocated to them in the ratesetting process. During the rate case BPA stated that it will purchase additional power to serve the DSIs. The costs of that acquired power are included in the rates the DSIs will pay. No other customer group will bear the costs of power acquired to serve the DSIs. Costs of the Energy Northwest nuclear plants are included with the costs of the FBS, which are allocated to all customer groups buying FBS power, including the DSIs.

Regarding power supply for the DSIs, one comment stated that BPA should sell secondary energy to the DSIs and let the DSIs shift part of their load to the local utility. Several stated that BPA should encourage the DSIs to conserve and/or buy clean electricity elsewhere, or clean up their emissions. Several commentors pointed out that the DSIs have spent money to conserve power, with good results. One commentor stated that the DSIs should remain faithful to BPA and commit to buying BPA power. One comment supported the augmentation plan. Several comments stated that system augmentation should come not from fossil fuels but from conservation, renewable resources, or fish friendly turbines. BPA sets its policies and rates consistent with mandates in Federal law and by means of processes that involve interested parties to the extent possible. The amounts and rate schedules for service to the DSIs that were proposed in the 2002 power rate case are designed to be consistent with statute, BPA's Power Subscription Strategy, and the Compromise Approach. BPA plans to make direct investments in new renewable resources, to continue its support of the Northwest Energy Efficiency Alliance (NEEA), and to invest in conservation resources as part of BPA's augmentation program to expand its resource availability to meet customer demands. BPA also is encouraging the DSIs to invest in conservation and renewables by offering to reduce their power rates in the amount of the C&R Discount. Both the DSIs and BPA require firm, reliable power to meet their business needs. Investments in conservation and renewables will provide significant benefits in the long term. In the meantime, both BPA and the DSIs realize the necessity of using primarily traditional power sources for reliability until the technology progresses.

Commentors stated that allocation of power should be to a plant, not to a company. This issue is addressed in ROD section 15.5.5.

One commentor stated that BPA should provide the DSIs with decent transmission rates if any DSIs install their own generation facilities to supplement purchases from BPA. BPA's provision of transmission services to any potential DSI-owned generation, and the rates for that service, are outside the scope of the 2002 power rate case.

Many commentors supported including a Good Corporate Citizenship Clause in the DSIs' new Subscription power sales contracts. Two petitions with over 14,000 names were submitted to the rate case record supporting the Clause. Six commentors recommended that BPA reject such a clause. Two other comments referred to the labor dispute at Kaiser Aluminum in general terms. These issues are outside the scope of the 2002 power rate case. The Kaiser labor dispute will be settled outside the rate case, and the Good Corporate Citizenship Clause is a contract matter. BPA conducted a separate public comment period for the Good Corporate Citizenship Clause and will use information received in that process to decide whether to include such a clause in contracts.

Conservation/Renewables	Field Hearings Comments	Letters Comments
a. The BPA is in kind of a funny place (in) that they are not necessarily trying to conserve energy. . .they are tending to be concerned about raising revenue to pay back things.	1	
b. BPA should verify that the monies spent on conservation are being properly used.	6	4
c. Meet conservation obligations, but not at the expense of today's needs or at excessive or subsidized costs.	2	1
d. BPA should invest in cost-effective energy conservation/wind/photovoltaics, etc. programs, including research.	8	9
e. Low-income conservation programs need to remain under state supervision.	5	5
f. Continue low-income conservation programs.	4	3
g. Increase rates to diminish demand.	2	
h. Increase the amount of money available for the conservation and renewables discount.	13	8
i. Establish a baseline for discount (regional standard), new acquisitions are truly new resources.	2	4
j. Conservation is a cheaper resource and has lower environmental effects.	3	1
k. Conservation work will create local jobs.	2	2
l. Hydropower is a clean, green power source; keep green power generating; it is a good source of peaking energy; cheaper than thermal.	4	

Discussion

Some commentors recommended that BPA increase the amount of money available for the C&R Discount. The amount of the C&R Discount was determined based on information received during a public involvement process that preceded the 2002 power rate case. The amount of the discount was based on the Comprehensive Review's recommendation for a public benefits spending goal, modified to recognize the competitive position of BPA's power price when compared with expectations of the Northwest energy market during the rate period. The cost of the C&R Discount raises BPA's applicable rates by the same half mill per kWh that would be credited to customers' Subscription power purchases. BPA is willing to accept the market risk at the current level, but a discount any higher might not be acceptable to customers and would be inconsistent with BPA's goal of rate stability.

Commentors stated that BPA should invest in cost-effective energy conservation and renewable resources programs, including research. Several comments stated that conservation is a cheaper resource and has lower environmental effects. Another comment stated that BPA is not necessarily trying to conserve energy but is more concerned about raising revenue. BPA plans to make direct investments in new renewable resources, to continue its support of the NEEA, and to invest in conservation resources as part of BPA's augmentation program to expand its resource availability to meet customer demands. BPA also is encouraging its customers to invest in conservation and renewables by offering to reduce their power rates in the amount of the C&R Discount. One commentor stated that conservation work will create local jobs. BPA agrees that this may be the case. Two commentors stated that BPA should increase rates to diminish demand. As stated elsewhere in this ROD, BPA sets its rates subject to many constraints, including Federal law and market forces. BPA's rates must be based on the costs to provide the power. Raising rates to diminish demand is not within BPA's authority and could harm BPA's customers and the retail consumers of regional utilities.

Several comments stated that hydropower is a clean, green power source and should be kept generating, especially for peaking, as it is cheaper than thermal generation. Other commentors stated that low-income weatherization programs should be continued and that low-income weatherization programs need to remain under state supervision. These issues are outside the scope of the rate case. *See* Issue 2 at ROD section 10.13 regarding funding for low-income weatherization programs; BPA has stated it would make good the funding, but BPA will consider an alternative outside the C&R Discount to continue funding low-income weatherization programs.

Several commentors stated that BPA should verify that money spent on conservation is being properly used. Others stated that BPA should establish a baseline for the C&R Discount to confirm that new acquisitions are truly new resources. BPA has monitoring programs in place for the conservation and renewables programs funded through rates. The C&R Discount also will be implemented with certain reporting requirements. The C&R Discount will include self-certification, required at investment levels up to 3 percent of retail sales. To qualify for the discount, customers will be able to use specific activities or measures developed by the Regional Technical Forum as approved by BPA. It is BPA's hope that future conservation and renewable development activities can be implemented and administered under local control. A few comments stated that BPA should meet its conservation obligations, but not at the expense of today's needs or at excessive or subsidized costs. BPA believes it is funding programs and encouraging conservation and renewables at proper levels, levels set using information from other relevant agencies, BPA's customers, and the public. Spending levels are not at issue in the rate case. *See* ROD section 5.3.

Irrigation	Field Hearings Comments	Letters Comments
a. The irrigated agricultural industry is highly sensitive to operational costs such as electric power.	6	4
b. Rate case imposes an unreasonable and unfair economic hardship on irrigators, especially during summer months.	5	4
c. The Northwest Power Act, in 3(18) states that only the first 400 horsepower during any monthly billing period of farm irrigation and pumping for any farm is eligible for the "residential use" or "residential load" classification. This is a hardship on farmers who pump out of deep wells (instead of canals or rivers).	2	
d. Rates have gone up 28 percent in the last three years; some pay twice through district assessment and increased pumping costs.	2	1
e. Rates have doubled in 10 years; where is the money going and how is it being used?	1	

<u>Discussion</u>

Commentors stated that the agricultural industry is highly sensitive to operational costs such as electric power. Others stated that the rate case imposes an unreasonable and unfair economic hardship on irrigators, especially during summer months. Several commentors stated that rates have gone up 28 percent in the last three years; some consumers pay twice through district assessment and increased pumping costs. One comment stated that rates have doubled in 10 years and asked where the money is going and how it is being used. BPA realizes the importance of keeping jobs in the region and using the relatively inexpensive output of the FCRPS to benefit the regional economy. BPA also is aware that the cost of electricity can be a large component of farming expenses. To address these concerns, BPA is continuing the LDD, is capping the Demand Charge and the Load Variance Charge, and is setting aside $4 million for relief for customers with a high proportion of irrigation loads. The foregoing list of rate impact mitigation measures is implemented in BPA's wholesale rates; how the local utility passes to consumers those benefits is not within BPA's control. Also not within BPA's control is fees assessed by local water districts and the like. As to where the money is going and how it is being used, the money BPA collects from rates goes to pay its expenses, including costs of the power generating resources, costs of programs to implement conservation and renewable resources, and costs for fish and wildlife recovery programs. *See* ROD section 5.3 for a discussion of BPA's spending levels.

Two comments stated that section 3(18) of the Northwest Power Act defines "residential use" or "residential load" as including only the first 400 horsepower during any monthly billing period of irrigation and pumping. This is a hardship on farmers who pump out of deep wells. BPA is implementing the measures described above in its rates to mitigate rate impacts, but there is no way to effect changes in the Federal statute through the 2002 power rate case. This topic is outside the scope of the rate case.

Marginal Cost Analysis	Field Hearings Comments	Letters Comments
a. Marginal cost should be tempered to: (1) recover the system's actual power production costs; or (2) make available power products to regional customers that will mitigate the effects of power markets outside the region.	1	1
b. Marginal costs should not ignore equity principles.	1	1

Discussion

Two comments stated that marginal cost should be tempered to recover the power system's actual power production costs or to make available power products to regional customers that will mitigate the effects of power markets outside the region. Two comments from the same commentors stated that marginal costs should not ignore equity principles. The Marginal Cost Analysis Study, WP-02-E-BPA-04, that BPA produces for the rate case is used for two purposes. One is to inform (but not directly set) the price level at which BPA buys and sells in the bulk power market. Second, the MCA provides a basis for sending price signals through BPA's rate design, such as the relative levels of the monthly energy rates. In competitive market pricing, the marginal cost of production is equivalent to the market clearing price. Rates patterned after market clearing prices send a signal to consumers about the marginal cost BPA sees in the energy market and will encourage economic efficiency.

Slice of the System	Field Hearings Comments	Letters Comments
a. Assure that Slice Product does not result in cost shifts.		3
b. The 20-year contract will give Slicers more rights to the power pie than full-requirements customers.		1

Discussion

Several comments stated that BPA should assure that the Slice product does not result in cost shifts. One commentor stated that a 20-year contract would give customers who purchase Slice more rights to the power pie than full requirements customers. Regarding cost shifts, the Slice product has been designed to assure that Slice participants pay their proportionate share of costs of the system. The Slice product design includes provisions that ensure appropriate cost recovery. BPA tested the Slice product design for cost shifts by conducting a Cost Shift Study, described in BPA's initial rate case testimony Mesa *et al.*, WP-02-E-BPA-32. The Slice product also bears an appropriate share of BPA's financial risk, and in fact the Slice participant will assume some of BPA's risks directly. BPA also will calculate or "true-up" the difference between the forecasted Slice Revenue Requirement and actual expenses and credits of the Slice Revenue Requirement. The Slice true-up adjustment charge will apply to the Slice product annually. The Subscription Strategy ROD states that the minimum Slice contract term will be 10 years, and BPA is asking for FERC approval of the methodology for 10 years. After continuing discussions with potential Slice participants, BPA has decided that the contract term will be 10 years. The Slice product is addressed in detail in ROD chapter 16 and Attachment 1.

19.0 TARGETED ADJUSTMENT CHARGE FOR UNCOMMITTED LOADS (TACUL)

In the initial proposal for the 2002 rate case, BPA proposed to establish an adjustment to the PF-96 and NR-96 rates, which are in effect through September 30, 2001. The TACUL is a charge that would be applied to an individual customer that purchases service for a load that was uncommitted and not included in BPA's 1996 rate case. Kitchen *et al*., WP-02-E-BPA-36, at 1. The TACUL is an adjustment to the 1996 PF Preference (PF-96) rate for customers who place this uncommitted load on BPA. *Id.* The TACUL also will apply to the NR-96 rate. Kitchen *et al*., WP-02-E-BPA-36(E), at 1. The purpose of the TACUL is to recover costs BPA may incur to provide firm power requirements service to those customers with loads uncommitted to BPA in the 1996 rate case and whose current power sales contracts expire on or before July 31, 2001. Kitchen *et al*., WP-02-E-BPA-36, at 2.

To understand BPA's purpose for establishing the TACUL, it is important to understand the competitive pressures and customer access issues associated with the drive by many customers of BPA to diversify their load away from BPA in the mid-1990s. At that time, the market price for wholesale power was at or below BPA's cost of power. Many customers decided that it was in their best economic interest to take their load off BPA. Demands by many customers to reduce their obligations to purchase Federal power under existing BPA contracts led BPA to offer both new contracts and amendatory agreements. These contracts and amendments specifically provide BPA the right to set a rate to cover the cost to serve uncommitted or diversified load that a customer later requests BPA to serve. Therefore, in order to recover the costs to serve the load demands placed on BPA by customers requesting to return uncommitted load to BPA, BPA has, consistent with the terms of the contracts and amendatory agreements, established the TACUL as part of this section 7(i) proceeding.

19.1 <u>BPA's Ratemaking Authority</u>

<u>Issue 1</u>

Whether TACUL violates the fundamental concepts of public preference and FBS cost-based rates.

<u>Parties' Positions</u>

PNGC states that the Administrator must set rates according to specific mandates contained in BPA's organic statutes to recover the cost of producing and transmitting electric energy, and must give preference and priority to public bodies and cooperatives (public preference customers) when selling its power. PNGC Brief, WP-02-B-PN-01, at 2. PNGC concludes the public preference customers were accorded the legal right to buy power from BPA on a first-priority basis, at cost. *Id.* PNGC also summarily describes the 7(b)(2) rate test that BPA is directed to apply in setting the rates charged by BPA to its preference customers. *Id.* PNGC argues that given the background it describes, it is apparent that the TACUL BPA proposed is fatally flawed and violates the mandates of the Northwest Power Act, as well as BPA's other organic statutes. *Id*. at 3. PNGC takes issue with the Draft ROD's assertion that the TACUL does not violate the concepts of preference and FBS cost-based rates. PNGC Ex. Brief, WP-02-R-PN-01, at 4.

PPC argues that the TACUL violates the same statutory rights, detailed in the discussion concerning the TAC charge, that protect preference customers from tiered, discriminatory rates. PPC Ex. Brief, WP-02-R-PP-01, at 7. OURCA adopts and joins PPC's position regarding the TACUL and also claims the Draft ROD "erroneously failed to eliminate the TACUL." OURCA Ex. Brief, WP-02-B-OU-01, at 6.

BPA's Position

The TACUL is a charge that would be applied to an individual customer that purchases service for a load that was uncommitted and not included in BPA's 1996 rate case. Kitchen *et al*., WP-02-E-BPA-36, at 1. The costs included in TACUL are FBS replacement costs. Kitchen *et al*., WP-02-E-BPA-50, at 2. The cost of the TACUL will be based on BPA's costs to replace the FBS to serve the specific uncommitted load the customer wishes to return to PF service. *Id.*

Evaluation of Positions

PNGC cites to the Bonneville Project Act of 1937, 16 U.S.C. §832-832m; the Northwest Power Act, 16 U.S.C. §839-839h; the Transmission System Act, 16 U.S.C. §838-838k; the Regional Preference Act of 1964, 16 U.S.C. §837-837h; and the FPA, 16 U.S.C. §824k(i) (FPA). PNGC quotes language from the Flood Control Act of 1944:

> Rate schedules shall be drawn having regard to the recovery . . . of the cost of producing and transmitting such electric energy . . . Preference in the sale of such power and energy shall be given to public bodies and cooperatives.

16 U.S.C. §825s. PNGC also quotes the following language from section 4(a) of the Bonneville Project Act:

> In order to insure that the facilities for the generation of electric energy at the BPA project shall be operated for the benefit of the general public, and particularly of domestic and rural consumers, the administrator shall at all times, in disposing of electric energy generated at such project, give preference and priority to public bodies and cooperatives.

16 U.S.C. §832c(a). PNGC also quotes section 7 of the Bonneville Project Act:

> Rate schedules shall be drawn having regard to the recovery . . . of the cost of producing and transmitting such electric energy, including the amortization of the capital investment over a reasonable period of years.

16 U.S.C. §832f. By reference to the TAC, PPC also quotes section 4(a) of the Bonneville Project Act, as well as section 7(b)(1) of the Northwest Power Act that provides that "the Administrator shall establish . . . rates . . . for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest . . . Such . . . rates shall recover the costs of that portion of the FBS resources needed to supply such loads . . . " 16 U.S.C. §839e(b)(1). PPC Ex. Brief, WP-02-R-PP-01, at 5. PPC then argues that these statutes, taken together with the protections afforded preference customers in section 7(b)(2) of the Northwest Power Act, provide those customers the right to purchase Federal power at BPA's lowest cost-based rate. *Id.*

PNGC identifies some but not all the statutory rate directives BPA is required to follow in establishing rates. PNGC, relying only on the two rate directives quoted and a passing reference to section 7(b)(2), wrongly concludes that it is "apparent" that BPA's TACUL is fatally flawed and violates BPA statutes.

The TACUL is an adjustment to the PF-96 rate for those customers who place their uncommitted load on BPA. Kitchen *et al*., WP-02-E-BPA-36, at 1. BPA's basis for identifying uncommitted loads is the actual load the customers elected to serve with non-Federal power during the FY 1996-2001 rate period. Kitchen *et al*., WP-02-E-BPA-50, at 3. The TACUL will provide BPA revenue protection against the costs of additional power that will be required to serve such load. Kitchen *et al*., WP-02-E-BPA-36, at 2.

Because PNGC fails to recognize the full spectrum of BPA's rate directives, PNGC is incorrect in its belief that BPA is somehow limited by statute from recovering the costs BPA incurs to serve uncommitted load.

BPA's TACUL is grounded on multiple BPA rate directives. The primary rate directives are set forth in section 7 of the Northwest Power Act which, among other things, provides that BPA establish rates in accordance with sections 9 and 10 of the Transmission System Act, section 5 of the Flood Control Act of 1944, and the provisions of the Northwest Power Act. Section 7(a) of the Northwest Power Act authorizes BPA to set rates within a wide discretionary range. Under section 7(b)(1) BPA is directed to "establish a rate or rates . . . " applicable to public body, cooperative, and Federal agency customers. Not only must such rates "have regard to" the recovery of the costs of the Bonneville Project, they must also recover the costs of all the resources in the FBS used to serve public body, cooperative, and Federal agency customers. Under section 7(e) BPA has broad authority to design rates to recover its total costs to meet its revenue requirement.

PPC quotes section 4(a) of the Bonneville Project Act. This provision of the Northwest Power Act directs the Administrator to give preference and priority to public bodies and cooperatives when disposing of electric energy. 16 U.S.C. §832c(a). No conflict exists, nor does the PPC identify one, between the Administrator's authority to establish the TACUL under BPA's rate directives and the Administrator's obligation to give preference and priority to public bodies and cooperatives. PPC also quotes language from section 7(b)(1) of the Northwest Power Act. PPC Ex. Brief, WP-02-R-PP-01, at 6. As noted above, section 7(b)(1) directs BPA to establish a rate or rates applicable to public body, cooperative, and Federal agency customers that "have regard to" the recovery of the costs of all the resources in the FBS needed to supply such load. PPC also claims that TACUL cannot be reconciled with the preference provisions in BPA's statutes, and cites to section 7(b)(2) of the Northwest Power Act. *Id*. This argument adds nothing to the PPC's claim. BPA established the PF-96 rate consistent with section 7(b)(2). As a result, customers purchasing under the PF-96 rate have been afforded the appropriate rate protection as required under section 7(b)(2). *See* Wholesale Power Rate Development Study, WP-96-FS-BPA-05A, at 195 (*see*, *e.g*., RDS 30 and RDS 31).

The Ninth Circuit Court of Appeals has recognized and upheld BPA's broad authority to design rates. "In short, the statute does not require BPA to impose any particular type of rate on its customers. Rather it restricts BPA only to 'sound business principles' in setting rates to meets its revenue requirements." *City of Seattle v. Johnson*, 813 F.2d 1364, 1367 (9th Cir. 1987). Given the multiple rate directives on which the TACUL is grounded, it is not "apparent" to BPA, as claimed by PNGC, that BPA's TACUL is fatally flawed or is violative of statute. To the contrary, the TACUL is legal. Based on this evaluation and analysis of the law and the record, BPA disagrees with OURCA's claim that it has "erroneously failed to eliminate the TACUL." *See* OURCA Ex. Brief, WP-02-R-OU-01, at 6.

Decision

The TACUL does not violate the concepts of preference and FBS cost-based rates. The TACUL is consistent with BPA's rate directives and is legal.

Issue 2

Whether TACUL is a market rate that violates BPA's statutory ratemaking authority.

Parties' Positions

PNGC argues that TACUL is a market rate that violates BPA's statutorily constrained ratemaking authority. PNGC Brief, WP-02-B-PN-01, at 4; PNGC Ex. Brief, WP-02-R-PN-01, at 4. PPC argues that the TACUL is not grounded on the cost-based rate provisions found at 16 U.S.C. §839e(b)(1). PPC Brief, WP-02-B-PP-01, at 30. ICNU argues that BPA witnesses admit that imposition of TACUL charges makes the cost of BPA power higher than the market price. ICNU Brief, WP-02-B-IN-02, at 9. OURCA contends that BPA is obligated to serve public preference customers at the posted PF-96 rate through September 30, 2001. OURCA Ex. Brief, WP-02-B-OU-01, at 6. When requested, BPA has an obligation to serve the net requirements load of preference customers. *Id*. The public preference customers are entitled to purchase power from the FBS at the cost of the FBS resource or at the rate test rate, whichever is lower. *Id*.

BPA's Position

BPA serves requirements loads with FBS resources. The TACUL is an adjustment to the PF-96 rate for those customers who place their uncommitted load on BPA. Kitchen *et al*., WP-02-E-BPA-36, at 1. The costs that are included in the TACUL are FBS replacement costs.

Kitchen *et al*., WP-02-E-BPA-50, at 2. The TACUL is a cost-based rate that is set to recover the cost of purchasing to meet load that is returning to BPA. *Id*. Under the TACUL, BPA will determine if firm power is available to serve a request. Kitchen *et al*., WP-02-E-BPA-36, at 3. If firm power is available, it will be used to serve the request, and the customer will be served at PF; if firm power is unavailable, the request will be served with incremental purchases and will face the TACUL. *Id*. BPA will establish the price based on the lesser of BPA's monthly cost to serve the incremental load by purchasing resources at market, or the average monthly cost of BPA recallable power contracts. Wholesale Power Rate Schedules, WP-02-E-BPA-07, at 128.

Evaluation of Positions

PNGC and PPC claim the TACUL includes fees (*i.e.*, handling fees and brokerage fees) totally unrelated to the FBS and which are outside the ratemaking framework established by Congress in the Northwest Power Act. PNGC Brief, WP-02-B-PN-01, at 4; PPC Brief, WP-02-B-PP-01, at 30. PNGC claims that TACUL charges are in direct violation of section 7(b) of the Northwest Power Act, section 825s of the Flood Control Act, and section 832c(a) of the Bonneville Project Act. PNGC argues further that TACUL has nothing to do with "the cost of production [sic] and transmitting such electric energy" or the "amortization of the capital investments over a reasonable period of years" as required by the referenced statutes. PNGC Brief, WP-02-B-PN-01, at 4. PPC claims that the TACUL is not grounded on the cost-based rate provisions found at 16 U.S.C. §839e(b)(1). PPC Brief, WP-02-B-PP-01, at 30.

PNGC acknowledges that BPA has "broad authority to design rates to recover its total costs to meet its revenue requirement," but PNGC argues that broad authority is "constrained by the fundamental principles of preference which mandate that rates be 'drawn having regard to the recovery . . . of the cost of producing and transmitting such electric energy.'" 16 U.S.C. §825s. PNGC Ex. Brief, WP-02-R-PN-01, at 4. PNGC argues that the TACUL rate is a rate based on market purchases and/or a market index of the costs of electricity, and thus, does not meet BPA's statement that rates must "recover the costs of all of the resources in the FBS used to serve public body, cooperative, and Federal agency customers." *Id.*

PNGC, PPC, and OURCA fail to recognize and understand that the cost that BPA incurs in acquiring resources to meet load is a cost that must be recovered. Contrary to PNGC's claim that BPA has statutorily constrained ratemaking authority, BPA's rate directives grant BPA broad authority to establish a rate such as the TACUL to recover the cost incurred to serve returning uncommitted load. Similarly, OURCA's argument that public preference customers are entitled to purchase power for the FBS at the cost of the FBS resource or at the rate test rate, whichever is lower, is not correct and does not recognize BPA's broad authority to set rates such as the TACUL. Regardless of whether the cost is related to a low-cost generation resource or to a power purchase in the wholesale market (including associated fees), when BPA includes such cost in the FBS it must recover that cost. *See* Kitchen *et al*., WP-02-E-BPA-50, at 2. Pursuant to section 3(10) of the Northwest Power Act, BPA may acquire resources to replace reductions in capability. Section 3(10) expressly provides that such replacement resources are FBS resources. For this reason, BPA's costs included in the TACUL to replace reductions in the capability of the FBS resources constitute FBS resources. Contrary to PNGC's and PPC's claim that the TACUL is in violation of section 7(b) of the Northwest Power Act and section 825s of the Flood Control

Act, and PNGC's claim that TACUL violates section 832c(a) of the Bonneville Project Act, the TACUL is legally grounded on multiple BPA rate directives. BPA's rate directives provide BPA with the authority to recover its costs and to establish a rate or rates that will recover the costs of the FBS used to serve BPA's public body, cooperative, and Federal agency customers, 16 U.S.C. §839e(b)(1), as well as broad rate design authority under section 7(e).

Section 7(e) of the Northwest Power Act grants the Administrator considerable rate design discretion, including the ability to employ rate designs that use a value-of-service approach or market-based approach, or rate designs which recover BPA's costs through formula rates or pricing methodologies. Section 7(e) provides that:

> Nothing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal, or other rate forms.

16 U.S.C. §839e(e). BPA's rates are certainly "cost based" in the sense that BPA's rates "have regard to" cost recovery and, in the aggregate, do ultimately result in total cost recovery. Nevertheless, within the context of those directives, section 7(e) and its legislative history make clear that the cost allocation directives concern the amount of revenues to be recovered from customer classes, and not the design of the rates to recover those revenues. Congress did not direct BPA to use specific rate structures or billing practices to show the cost of new power supplies. As a result, it was recognized that many provisions could lead to rate reforms. *See, e.g.*, *Comptroller General of the United States, Comments on Pacific Northwest Power Planning and Conservation Act—H.R. 8157*, reprinted in Cong. Rec. H 10687 (November 17, 1980).

The language PNGC cites in support of its argument that TACUL is unrelated to BPA's cost further ignores section 7(a) of the Northwest Power Act, which requires that BPA's "rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the cost associated with the acquisition, . . . of electric power, . . ." Contrary to PNGC's assertion, BPA's rate directives do not limit BPA from including the cost of resources, including power available from the market, acquired to replace the FBS in the rates established under section 7(b)(1).

PNGC makes the assertion that the TACUL is an "opportunity cost" based rate that BPA views as a cost-based rate. PNGC Brief, WP-02-B-PN-01, at 4. PNGC provides no evidence in the record to support its claim that the TACUL is an "opportunity cost rate." BPA rejects this characterization of the TACUL. BPA has testified that the TACUL is a cost-based rate that is set to recover the cost of purchasing to meet load that is returning to BPA. Kitchen *et al.*, WP-02-E-BPA-50, at 2. PNGC then claims the PF-96 rate, which it thought it was contracting for, was either the existing PF-96 rate or some updated embedded cost rate. PNCG Brief, WP-02-B-PN-01, at 5. PNGC describes its understanding of what it thought "cost-based rates" meant, and states that if PNGC understood that the TACUL would expose PNGC to a market rate, PNGC would have simply stayed in the market itself. *Id.*; PNGC Ex. Brief, WP-02-R-PN-01, at 3. PNGC argues that the actual contracts entered into between BPA and the diversifying utilities explicitly provide that returned load would be served at a "PF rate or rates" and not at full incremental cost. *Id.* at 4. Despite what PNGC may have understood, BPA discussed the nature of the type of rate BPA would establish to serve uncommitted load later returned to BPA service in the Administrator's ROD on Templates (New Power Sales Contracts) and Amendatory Agreement No. 7 (AA7) (published May 13, 1996) [hereinafter AA7 ROD]. Under these agreements, customers that chose to diversify their load away from BPA agreed to allow BPA to establish a separate or new rate to serve load subsequently returned to requirements service. The AA7 ROD was published after many public meetings with BPA customers on contract templates and the future business relationship between BPA and its customers. In particular, the AA7 ROD states that customers who diversify and wish to "reestablish service will not get the PF rate available to the loads which stayed with BPA, but will pay at least the *full incremental cost* associated with providing that service, as set through a 7(i) process." AA7 ROD at 10 (emphasis added). PNGC argues that the contract language "PF rate or rates" negated the AA7 template language. PNGC Ex. Brief, WP-02-R-PN-01, at 4. PNGC's logic appears to be that if the contract did not actually state an incremental cost rate, then the language "a PF rate or rates" cannot include incremental costs. The language "a PF rate or rates" is consistent and predicated on BPA's rate directives. BPA serves customers purchasing PF power under the PF power rate. The language in the contract acknowledges this. At the same time, the contract does not specify the particular PF rate such load would be served under. No PF rate assurance was given in the contract concerning which PF rate or rates would apply to serve uncommitted load. Therefore, the contract language did not negate the AA7 policy to charge returned load the full incremental cost associated with serving such load, as claimed by PNGC.

Finally, ICNU argues that BPA admits the TACUL will be higher than market. ICNU Brief, WP-02-B-IN-02, at 9. ICNU cites to BPA witnesses' cross-examination testimony (Tr. 1439, lines 15-23) to support this claim. Review of the transcript makes clear that BPA made no such admission.

> Q. Had these customers stayed in the market with this diversified load for August and September and not returned to BPA until October 1st, they would be paying about the same thing, would not they, except for maybe they would save BPA's internal handling fees?
>
> A. (Ms. Arrington) That's probably right.

As this dialogue shows, the BPA witness was engaged in a purely hypothetical line of questioning regarding what costs may be included in the TACUL. Because ICNU's claim is not supported by the record, it is rejected. Moreover, it is not certain that TACUL will always result in a higher charge than the base PF-96 rate. If firm power is available, it will be used to serve the request, and the customer will be served at PF. Kitchen *et al.*, WP-02-E-BPA-36, at 3.

<u>Decision</u>

The TACUL is a rate based on BPA costs to replace the FBS and is not a market rate that violates BPA's statutory ratemaking authority.

Issue 3

Whether the TACUL was set in violation of the Northwest Power Act section 7(i) ratesetting directives.

Parties' Positions

PNGC argues that the TACUL was set in violation of the 7(i) process. PNGC Brief, WP-02-B-PN-01, at 5; PNGC Ex. Brief, WP-02-R-PN-01, at 5.

BPA's Position

BPA decided to use this current section 7(i) rate proceeding to establish the TACUL because BPA determined that it was necessary only to add a charge to the PF-96 rate to reflect the cost it incurs to serve returned incremental load. Kitchen *et al*., WP-02-E-BPA-50, at 9. Since it is not certain that BPA's service to such load will result in increased costs, the TACUL provides flexibility to recover costs only when the cost is certain to occur. Second, parties can take advantage of the timing of this current section 7(i) rate proceeding. *Id*. This lessens the administrative burden and cost associated with having an additional section 7(i) process for the sole purpose of establishing a new PF rate to apply to returned load. *Id*.

Evaluation of Positions

PNGC notes that it and other parties argued in their testimony that BPA failed to begin a 7(i) proceeding for purposes of developing a new PF rate. PNGC Brief, WP-02-B-PN-01, at 5; Sabala *et al*., WP-02-E-PN-06, at 11; Opatrny *et al*., WP-02-E-PP-02. PNGC argues that the PF-96 rates were set in the PF-96 proceeding, using loads and costs for that test period, pursuant to duly noticed and procedurally accurate proceedings, and that there is no PF-96 proceeding open for the purpose of establishing a new PF-96 rate. PNGC Brief, WP-02-B-PN-01, at 5. Further, PNGC argues that the TACUL is being discussed in the current public process but that the revenue and load data needed to support a PF rate were never provided. PNGC Ex. Brief, WP-02-R-PN-01, at 5.

PNGC's argument is not persuasive. This current section 7(i) rate proceeding is the appropriate forum to establish the TACUL. PNGC argues that the revenue and load data that are needed to support a PF rate were never provided. However, BPA determined that it was necessary only to add a charge to the PF-96 rate to reflect the cost BPA incurs to serve returned incremental load. Kitchen *et al*., WP-02-E-BPA-50, at 9. The load will be served at the PF-96 rate, for which load and resource data are available from the 1996 rate case, plus the TACUL. The TACUL will be determined individually and based on BPA's cost to replace the FBS to serve the specific uncommitted load the customer wishes to return to PF service. *Id.* at 9, 10. BPA proposed to establish an adjustment to the PF-96 rate, which is in effect through September 30, 2001. These customers participated in the 1996 rate case and again in this 7(i) proceeding that is establishing the TACUL. Thus, due process is being served in the current 7(i) process.

Although PNGC argues that it is not within BPA's discretion to determine who is and who is not entitled to have their rate set according to the specific procedures required by law, PNGC Brief, WP-02-B-PN-01, at 5; this adjustment, the TACUL, is targeted to apply to those customers that request BPA to provide service to load that was not committed to BPA for service under contract nor forecast to be served under the effective PF-96 rate. Kitchen *et al.*, WP-02-E-BPA-36, at 2. PNGC argues that for due process to afford any benefit, the diversifying customers should be able to make their decisions with advance knowledge of the possibility of a non-PF TACUL. PNGC Ex. Brief, WP-02-R-PN-01, at 5. BPA rejects PNGC's characterization that the TACUL is a non-PF based rate. The TACUL is PF based. The TACUL will recover the additional cost of serving uncommitted customer load returned to requirements service. Kitchen *et al.*, WP-02-E-BPA-36, at 2. The methodology of the TACUL provides that if no incremental cost is incurred, then the TACUL will be the PF-96 rate. *Id*. at 3.

PNGC, like other parties, is being provided all the procedural opportunities and safeguards consistent with Northwest Power Act section 7(i) to make its case regarding the proposed TACUL. PNGC even describes the procedures that have been provided in this section 7(i) proceeding: publication of notice of the proposed rates in the Federal Register, holding one or more public hearings, providing the opportunity to be heard through direct and rebuttal testimony, allowing cross-examination of the evidence, and the other procedural safeguards inherent in any contested quasi-judicial proceeding. PNGC Brief, WP-02-B-PN-01, at 5. It is apparent that the instant proceeding is working, as is evident from the testimony filed by parties opposing BPA's proposed TACUL. Kitchen *et al.*, WP-02-E-BPA-50, at 9. PNGC claims, however, that it is working in the wrong rate case. PNGC Brief, WP-02-B-PN-01, at 5. PNGC notes that the PF-02 rate proceeding is progressing in the same manner as the PF-96 proceeding, using loads and costs for that test period, pursuant to duly noticed and procedurally accurate proceedings. *Id*. PNGC's argument is not persuasive. In forecasting the load that is subject to the TACUL in this section 7(i) proceeding, BPA testified that BPA's basis for identifying uncommitted loads is the actual load customers elected to serve with non-Federal power during the 1996-2001 rate period. Kitchen *et al.*, WP-02-E-BPA-50, at 3. A number of customers have given notice that they will return previously uncommitted load to BPA requirements service. Kitchen *et al.*, WP-02-E-BPA-36, at 4. BPA is forecasting, on an annual average basis, that this load will total approximately 72 aMW in Operating Year (OY) 2001 and 43 aMW in OY 2002. *Id*. BPA will price the TACUL to apply to each individual customer requesting service based on the size of that customer's request and the cost to BPA to purchase power to meet that request. *Id*.

PNGC argues that there is a due process harm because the TACUL was proposed, and if it is adopted, PNGC alleges, it will have a retroactive effect. PNGC Brief, WP-02-B-PN-01, at 6; PNGC Ex. Brief, WP-02-R-PN-01, at 5. PNGC adds that the customers who are going to be subject to TACUL have made decisions relative to whether to diversify based on what they know about BPA's rate structure and financial goals adopted in the 1996 rate case. *Id*. PNGC contends the TACUL is proposed to be assessed against customers who signed up to diversify their load years ago without any advance notice or knowledge that a market-based TACUL rate would be applied to their returned load. PNGC Brief, WP-02-B-PN-01, at 6.

It is clear that PNGC simply does not like the proposed TACUL and does not like its members' contracts with BPA that afforded them notice that if BPA determined it necessary, BPA would establish a rate such as the TACUL. Despite PNGC's contention, customers who diversified their load under new contracts or amendatory agreements were given notice that load subsequently returned to BPA requirements service would be subject to a separate or new rate established to recover the full incremental cost of serving such load. AA7 ROD, at 10. BPA does not agree that customers that diversified did so based on BPA's rate structure and financial goals in the 1996 case. BPA believes that customers' decisions to diversify were based largely on economics and were manifest through their desire to access resources that were less expensive than BPA's rates. In the process of developing the contracts, BPA was explicit regarding the fact that BPA would reserve the right to charge the customer for the cost of serving the load returned such that BPA's other, non-diversified customers would not be impacted. *Id*.

> The two-year notice period will give customers the right to return but allow BPA the opportunity to establish a separate requirements rate that ensures the returning customer pays the actual cost of their return and that their return does not economically harm customers that had chosen to leave their load on BPA.

Id.

Contrary to PNGC's account, notice of a new or separate rate or rates, such as the TACUL, was given in the AA7 ROD. BPA and those customers with the right to return load under AA7 and the 1996 contracts agreed that BPA could establish a rate to apply to the service of any such customer-returned load. Kitchen *et al*., WP-02-E-BPA-36, at 2. Moreover, in general rate case workshops held before BPA filed its initial rate proposal, the subject of TACUL was discussed with representatives of customers. Tr. 1119. Application of the TACUL would not have a retroactive effect.

Decision

The TACUL is being set consistent with the rate directives of Northwest Power Act section 7(i).

19.2 Uncommitted Loads/Diversification Issues

Issue 1

Whether TACUL unjustly discriminates both between and among diversified customers and between diversified customers and other preference customers of BPA.

Parties' Positions

PNGC argues that the TACUL rate is applied on an arbitrary basis and is unduly discriminatory. PNGC Brief, WP-02-B-PN-01, at 9. PNGC states that the decision as to which customers would be forced to pay the TACUL was made internally at BPA with no customer input. *Id*. PNGC argues that BPA had no basis upon which it could assume these customers would no longer be preference customers after the expiration of their diversification contracts. *Id*. ICNU notes that a preference customer will pay different rates for power depending on whether its load was served before or after 1996, and regardless of whether the customer is currently serving that load. ICNU Brief, WP-02-B-IN-01, at 8.

PNGC states that the customers that are potentially subject to the TACUL have a statutory right to continue their preference service, and that BPA has no basis on which to deny these customers their entitlement to preference power. PNGC Brief, WP-02-B-PN-01, at 10. PNGC argues that the TACUL charge treats one set of preference customers of BPA differently from another without any cost basis for doing so. *Id*. PNGC argues that the impacts of higher overall costs should rightfully be borne by all classes of customers. *Id*. PNGC estimates that the difference between the projected market price of electricity for August and September 2001, and the PF-96 rate for those months for the 32 aMW at issue is at least $5 million. *Id*. PNGC further argues that the TACUL unduly discriminates because there is no difference in the cost to serve the returned load from other load on BPA's system. PNGC Ex. Brief, WP-02-R-PN-01, at 6.

<u>BPA's Position</u>

Customers subject to the TACUL are PF customers that currently purchase requirements firm power from BPA under: (1) 1981 power sales contracts that expire on or before July 31, 2001, as may be amended; and (2) AA7 to the 1981 power sales contracts, or new "1996" power sales contracts, where the customer provides BPA notice after December 7, 1998, for requirements service for the period after December 7, 2000, and prior to September 30, 2001, consistent with the terms of the customer's power sales contract. Kitchen *et al*., WP-02-E-BPA-36, at 3. Customers that diversified their power supply by signing either an AA7 or a new "1996" power sales contract agreed that BPA had the right to establish a rate to serve loads should these customers return to firm power requirements service. *Id*.

The cost of the TACUL will be based on BPA's cost to replace the FBS to serve the specific uncommitted load the customer wishes to return to PF service. Kitchen *et al*., WP-02-E-BPA-50, at 9-10. Because these loads are returning to BPA service, they are an additional load to the base 1996 rates and may require additional FBS resources. *Id*. at 10. Since these loads can be identified as loads in addition to the customer's load that BPA is already obligated to serve during the FY 1996-2001 rate period, the costs incurred to serve such additional loads can be identified. *Id*. BPA will base the cost to serve these additional loads on the costs that BPA will incur to serve the additional load. *Id*.

<u>Evaluation of Positions</u>

PNGC makes several arguments to support its contention that the proposed TACUL is unjust and unduly discriminatory both between and among diversified customers, and between diversified customers and other preference customers of BPA. First, PNGC argues that the TACUL discriminates against customers that diversified and those that did not. To support its argument, PNGC relies on the Federal Power Act, 16 U.S.C. §824d(b), and selected pages in publications on regulating public utilities. PNGC Brief, WP-02-B-PN-01, at 7; citing Phillips, *The Regulation of Public Utilities*, 411-12 (2d ed. 1988), and Bonbright, *Principles of Public Utility Rates*, 515-546 (1988).

BPA notes that neither the section of statute cited by PNGC nor the publications govern BPA's ratemaking. BPA establishes rates in accordance with section 7 of the Northwest Power Act. The TACUL is neither unjust nor unduly discriminatory. TACUL targets and applies to customers with uncommitted load who now request to return such load to requirements service. Kitchen *et al*., WP-02-E-BPA-36, at 2. The TACUL will provide BPA revenue protection against the cost of additional power that will be required to serve such load. *Id*. Such a rate is consistent with the primary directives of section 7 that BPA recover its total costs. BPA is forecasting that market prices will be above BPA's PF power costs and that firm inventory will be unavailable to serve this additional load. *Id*. If market prices are above PF and BPA is required to serve incremental loads by purchasing at market, then the TACUL would hold BPA financially harmless from having to purchase at market to serve incremental loads. *Id*. Customers that diversified their power supply by signing either an AA7 or "1996" power sales contract agreed that BPA had the right to establish a rate to serve loads should these customers return to firm power requirements service. *Id*. at 3.

PNGC argues that the TACUL is arbitrary and *per se* unduly discriminatory because it would apply to some but not all load of the customers who diversified. PNGC Brief, WP-02-B-PN-01, at 7.

ICNU concludes that the end result is that preference customers will not be treated the same and will pay different power rates based on when they seek to purchase power under BPA's PF rate. ICNU Brief, WP-02-B-IN-01, at 8. PNGC refers to a December 7, 1998, decision by BPA to establish the TACUL as arbitrary because there was no customer input or notice. PNGC points out that some customers that were not subject to the TACUL had already made requests to return load to BPA. PNGC Brief, WP-02-B-PN-01, at 7. PNGC also argues that the timing of BPA's decision is not relevant to BPA's cost to serve. *Id*. at 8. PNGC argues that BPA ignored the argument that temporal discriminatory actions by utilities are *per se* discriminatory absent other discrete distinguishable cost causing factors. PNGC Ex. Brief, WP-02-R-PN-01, at 6. That is, the returned load in August and September of 2001 places no different costs on BPA than customers who provided notice of returned load prior to December 7, 1998, and there is no way for BPA to distinguish which of its customers will cause it to experience increased costs in those two months, because all of BPA's customers cause increased costs. *Id.* at 5-6. For the foregoing reasons, PNGC concludes that BPA should simply not establish the TACUL at all because those prior requests, including a large amount of PNGC's own diversified load, will not be subject to the TACUL. PNGC Brief, WP-02-B-PP-01, at 7-8.

BPA's decision to establish the TACUL was not arbitrary. Nor is the TACUL arbitrary and *per se* unduly discriminatory. Contrary to PNGC's argument that the timing of when BPA decided to establish the TACUL is *per se* discriminatory absent "discrete distinguishable cost causing factors," the increase in the amount of uncommitted load returning to BPA relates to the timing of BPA decisions to establish the TACUL to recover the "discrete distinguishable cost" associated with serving such load. As more customers made requests to return diversified load, which increased the amount of power BPA would be obligated to supply, BPA took the prudent step to determine the availability of its supply on a planning basis. Kitchen *et al.*, WP-02-E-BPA-50, at 8. Making this determination was consistent with BPA's contract right to establish the TACUL. The December 7, 1998, decision to establish the TACUL was based on preliminary results from BPA's Loads and Resources Study, WP-02-E-BPA-01, which showed that on a planning basis BPA would be required to purchase power to meet further requests by customers to return additional diversified load. *Id*. Recognizing its contract right to establish a separate or new rate to serve such load, BPA made the decision to exercise that right. This decision was BPA's alone. It did not require customer notice or input. BPA determined that it would be financially harmed if it served additional loads without having a charge to reflect BPA's costs of purchasing resources to serve additional returning uncommitted load. Tr. 1116.

PNGC states that BPA had no basis on which it could assume "these customers" would no longer be preference customers after the expiration of their diversification contracts. PNGC Brief, WP-02-B-PN-01, at 9. BPA is not certain who "these customers" are that PNGC refers to; nonetheless, BPA has not stated such a basis, nor has BPA denied preference to customers accorded preference. PNGC member cooperatives are certainly assumed to continue to be preference customers upon expiration of their diversification contracts. PNGC argues that because its members are preference customers they should be entitled to cost-based rates like all other preference customers, and that the cost BPA would otherwise incur to serve PNGC members should be borne by all classes of customers. PNGC Brief, WP-02-B-PN-01, at 10. PNGC contends that section 7(g) of the Northwest Power Act constrains BPA to apply generally accepted ratemaking principles which disfavor undue and unjust discrimination. PNGC Brief, WP-02-B-PN-01, at 10. PNGC contends further that nothing in the history of the Northwest Power Act contemplates the notion that BPA would discriminate in ratemaking against a class of customers who acquired a contract resource which then expired, resulting in the load coming back to BPA. *Id.*

The TACUL does not, as claimed by PNGC, result in undue and unjust discrimination. Section 7(g) requires that BPA "equitably allocate" to power rates certain costs in accordance with generally accepted ratemaking principles and other provisions of the Northwest Power Act. But even this directive to allocate was premised upon the over-arching obligation of the Administrator to recover total costs. Congress stated with regard to section 7(g) that:

> The costs and benefits under this section 7(g) are intended to be applied in an equitable manner and as appropriate to any or all of the rates for power sales of the Administrator in order to assure that [she] can meet the requirements of section 7(a) to collect sufficient revenues to recover all of [her] costs . . .

S. Rep. No. 96-272, 96th Cong., 1st Sess. 32 (1979). BPA believes it is appropriate that those customers that cause the costs to be incurred related to serving uncommitted load should be subject to the TACUL. If one accepts PNGC's proposition, BPA would not be allocating costs and benefits in an equitable manner if the costs BPA incurs to serve returning uncommitted load are borne by all customers. BPA believes that in this situation it is appropriate to protect those customers not causing the costs to be incurred. The causation for these costs is easily identified and attributable to returning uncommitted load; therefore, it is just and reasonable to design the TACUL to recover the specific incremental power costs associated with supplying such load.

Decision

The TACUL is not discriminatory either between and among diversified customers or between diversified customers and other preference customers of BPA.

Issue 2

Whether the PF TACUL is discriminatory and is a charge against loads that cannot be distinguished from the other PF loads that will not be assessed a TACUL charge.

Parties' Positions

PPC argues that the PF TACUL is a charge against loads that cannot be distinguished from other PF loads that will not be assessed a TAC charge. PPC Brief, WP-02-B-PP-01, at 31. PPC argues that BPA's "TAC logic" compels the conclusion that PF TACUL loads are "expected," because BPA has known about the loads well in advance of the September 30, 2000, cutoff for "expected" loads. *Id*. In addition, PPC argues that there is nothing to distinguish these PF TACUL loads from the IOU loads, including the 100 aMW of incremental load at issue in this case under BPA's IOU settlement sales, which would be immune from TAC. *Id*. PPC claims that BPA characterizes the IOU 100 aMW as "expected" load. *Id.* PPC argues that such characterizations are arbitrary and discriminatory and produce a rate structure that cannot be supported under the law. *Id*.; PPC Ex. Brief, WP-02-R-PP-01, at 6.

BPA's Position

The TACUL will be charged to all customers that meet certain criteria; that is, the TACUL will be paid by all customers that return uncommitted customer load to requirements service after December 7, 2000, through September 2001. Kitchen *et al*., WP-02-E-BPA-36, at 2. BPA and those customers with the right to return load under AA7 and the 1996 contracts agreed that BPA could establish a rate to apply to the service of any such customer-returned load. *Id*. The cost of the TACUL will be based on BPA's cost to replace the FBS to serve the specific uncommitted load the customer wishes to return to PF service. Kitchen *et al*., WP-02-E-BPA-50, at 9-10. Because these loads are returning to BPA service, they are an additional load to the base 1996 rates and require additional FBS resources. *Id*. at 10. Since these loads can be identified as loads in addition to the customer's load that BPA is already obligated to serve during the FY 1996-2001 rate period, the costs incurred to serve such additional loads can be identified. *Id*. BPA will base the cost to serve these additional loads on the costs that BPA will incur to serve the additional load. *Id*.

Evaluation of Positions

PPC's argument that BPA's "TAC logic" renders load that would be subject to the TACUL as "expected" is misplaced and illogical. PPC's argument would require that BPA replace the PF-96 rate basis and current contract terms used for determining uncommitted load and substitute them with the timeframe that will be used to determine or measure when load is "expected" for purposes of the PF-02 rate. PPC makes a secondary argument that nothing distinguishes uncommitted load subject to the TACUL from IOU loads, such as the 100 aMW incremental load at issue in the 2002 power rate case. PPC Brief, WP-02-B-PP-01, at 31. PPC further states that it has demonstrated that the loads to which BPA seeks to apply a TACUL charge are indistinguishable from other loads that will not be assessed a TACUL charge, including the proposed 100 aMW of incremental load to be sold to the IOUs. PPC Ex. Brief, WP-02-R-PP-01, at 6. PPC contends that "[d]isparate treatment of similar loads is arbitrary, capricious and produces a rate structure unsupported by law." *Id.*

Contrary to PPC's assertion that BPA characterizations are arbitrary and discriminatory, the fact is that uncommitted load that is returning to requirements service under current contracts is distinct in several ways from IOU loads that may be served in the future. First, the 100 aMW of IOU incremental load that PPC points to is included in studies of load that BPA is forecasting will be served by BPA under future contracts and under a new rate schedule, not the PF-96 rate. *See* Arrington *et al*., WP-02-E-BPA-49, at 5. Second, neither the 100 aMW of load nor any other amount of load has been requested by any IOU to be served as uncommitted load returned under their existing BPA contracts. Any such requests to serve uncommitted IOU load will be similarly subject to an NR TACUL. Kitchen *et al*., WP-02-E-BPA-36(E1). Finally, the amounts of uncommitted load that customers wish to return now were not forecast, *i.e.*, "expected," to be served under the PF-96 rate. BPA made forecasts of the amount of diversification that could be expected to occur in the rate period. Kitchen *et al*., WP-02-E-BPA-50, at 3. That information was an estimate. Indeed, the actual amount of diversification by BPA's preference customers was greater than that which BPA forecasted, which results in a greater amount of load being uncommitted during the FY 1996-2001 rate period. *Id*. The 1996 ROD described this situation clearly:

> In fact, BPA has continued to lose sales during the course of this rate proceeding . . . [P]rojections of public utility purchases from BPA have been reduced to account for utilities that are seeking actively other suppliers . . . Even so, customers represented by the WPAG argue that BPA has misjudged its position in wholesale market, and has grossly underestimated the desire of its preference customers to diversify their power supply. Beck, *et al*., WP-96-E-WA-13, at 6, 10-11. They note that, at the time their testimony was submitted in November 1995, preference customers had made submissions to BPA pursuant to their power sales contracts to reduce their load on BPA by over 780 aMW, and that they expected to see this number increase. *Id*. Since that time, some of these customers have sued BPA in an attempt to access alternative power suppliers.

1996 ROD, at 18. In summary, PPC confuses the basis for determining uncommitted load for purposes of TACUL under the PF-96 rate with the application of the TAC to the PF-02 rate.

<u>Decision</u>

The PF TACUL is not discriminatory, because the loads subject to the TACUL can be distinguished from the other PF loads that will not be assessed a TACUL charge.

Issue 3

Whether the diversification contracts between PNGC diversifying customers and BPA allow the TACUL to be imposed.

Parties' Positions

PNGC argues that BPA is prohibited from applying the TACUL to load that PNGC member utilities are returning to PF service under their existing contracts for the period from November 2000 through April 2001, because BPA was given 24-month notice as required by contract. Sabala *et al*., WP-02-E-PN-06, at 10. PNGC argues that the original diversification agreements limit BPA's ability to apply "a separate PF rate" to just those time periods that are encompassed by the terms of the diversification agreements themselves. PNGC Brief, WP-02-B-PN-01, at 11.

BPA's Position

PNGC member utilities provided the 24-month written notice to BPA as required under the terms of their existing contracts with BPA. Kitchen *et al*., WP-02-E-BPA-50, at 8. The load specified by each utility that is returning to PF service during the period from November 2000 through April 2001 will be served at the PF-96 rate without the TACUL. *Id*. At the time the PNGC member utilities made their request to return load, BPA determined that it did not need to set a new rate or TACUL to serve such load. *Id*.

July, August, and September 2001 are months in which some of BPA's customers will not have a contract to purchase because their existing power sales contracts expire either June 30, 2001, or July 31, 2001. *Id*. Such customers have the right to request new contracts to purchase power from BPA upon expiration of their existing contracts; or they may amend their existing contract to extend its duration through September 30, 2001. *Id*. BPA's proposal to establish the TACUL in this section 7(i) rate proceeding means that a customer that chooses either to extend the term of its existing contract or to execute a new contract would be subject to the TACUL for its previously uncommitted load during the July through September 2001 period. *Id*. PNGC members chose to extend the term of their existing contracts through September 30, 2001, and agreed that BPA may establish a new PF rate to serve their returned load. *Id*.

Evaluation of Positions

PNGC argues that because the original agreements terminated on July 30, 2001 (Tr. 1424), BPA's attempt to assess a TACUL in August and September 2001 is not permitted by those agreements, as represented by the BPA TACUL panel. PNGC Brief, WP-02-B-PN-01, at 11. PNGC argues that section 12(g) of the contract (WP-02-E-PN-14) provided only for the possibility of a new PF rate for load which was diversified during the term of the original contracts, and PNGC's member loads for August and September were not so diversified. *Id*. Thus, PNGC argues that BPA must treat this entire load as it would any other preference customer's load and assess the PF rate in effect at the time, which is the current PF-96 rate. *Id*. at 12.

BPA is not persuaded by PNGC's position for several reasons. First, section 12(g) of the contract, which PNGC references in its brief, clearly provides that the parties agreed that the provisions of section 12(g) would remain after expiration or termination of the contract. *See* PNGC Brief, WP-02-B-PN-01, at 11; WP-02-E-PN-14. Second, BPA has broad authority to design rates under section 7(e) of the Northwest Power Act. If costs that were not previously forecast to be served in the rate period will be incurred to serve uncommitted load, BPA has the authority to set a rate that will recover its cost to serve such load. Third, BPA witnesses testified in cross-examination that TACUL remains an issue for the two months because of the diversification pattern that existed in the previous five years under the PNGC members' contracts. Tr. 1433. Fourth, PNGC's portion of load that is subject to the TACUL in August and September is load that has been uncommitted to BPA service.

The TACUL is intended to apply to a customer that chooses either to extend the term of its existing contract or to execute a new contract, which would provide requirements service to previously uncommitted load during the July through September 2001 period. Kitchen *et al*., WP-02-E-BPA-50, at 9. PNGC members chose to extend the term of their existing contracts through September 30, 2001, and agreed that BPA may establish a new PF rate to serve their returned load. *Id*.

Decision

The diversification contracts between PNGC diversifying customers and BPA allow the TACUL to be imposed.

Issue 4

Whether the diversification agreements between BPA and PNGC member cooperatives allow BPA to establish a new rate or rates.

Parties' Positions

PNGC argues that "the amended PNGC member contracts with Bonneville that permitted diversification do specifically permit Bonneville to establish a new PF rate in August and September of 2001 [sic]." PNGC Brief, WP-02-B-PN-01, at 12. But "those contracts do not permit Bonneville to establish any rate that it wishes." *Id*. Rather, the "contract as amended, provides that Bonneville may elect to establish a new *PF rate*." *Id*. (emphasis in original). PNGC argues that the TACUL violates the explicit restriction contained in BPA's contracts with the diversifying customers by attempting to establish a market rate that is not an embedded cost-based PF rate. *Id*. PNGC argues that the TACUL is not a PF rate. PNGC Ex. Brief, WP-02-R-PN-01, at 6.

BPA's Position

Customers that diversified their power supply by signing an AA7 or a new "1996" power sales contract agreed that BPA had the right to establish a rate to serve loads should these customers return to firm power requirements service. Kitchen *et al*., WP-02-E-BPA-36, at 3. The TACUL will apply to a customer that chooses either to extend the term of its existing contract or to execute a new contract which would provide requirements service to previously uncommitted load during the July through September 2001 period. Kitchen *et al*., WP-02-E-BPA-50, at 9. PNGC members chose to extend the term of their existing contracts through September 30, 2001, and agreed that BPA may establish a new PF rate to serve their returned load. *Id*.

Evaluation of Positions

PNGC argues that the PNGC member contracts with BPA that permitted diversification allow BPA to establish a new PF rate in August and September 2001, but those contracts do not permit BPA to establish any rate that it wishes; rather, the contract as amended provides BPA with the right to establish a new PF rate. PNGC Brief, WP-02-B-PN-01, at 12. PNGC makes an argument based on semantics that does not overcome the applicability of the TACUL to previously uncommitted load that will be served by BPA in August and September 2001. There is no basis to support PNGC's contention that there is a distinction to be drawn over the terms used in the PNGC's members' contracts to describe the rate BPA has the right to establish. Whether the term used is "separate PF rate or rates" or "new PF rate," the fact remains that if the load was uncommitted, the TACUL will apply during the months of August and September 2001. Because these loads are returning to BPA service, they are an additional load to the base 1996 rates and require additional FBS resources. Kitchen *et al*., WP-02-E-BPA-50, at 10. Since these loads can be identified as loads in addition to the customer's load that BPA is already obligated to serve during the 1996-2001 rate period, the costs incurred to serve such additional loads can be identified. *Id*.

PNGC states that the Draft ROD, WP-02-A-01, at 19-13 through 19-16 concludes that the diversification contracts allow the TACUL to be imposed and that the TACUL should be set as a "new PF rate." PNGC Ex. Brief, WP-02-R-PN-01, at 6. PNGC argues, however, that the Draft ROD does not recognize that "the TACUL is not a PF rate" as discussed in PNGC's initial brief. *Id*. Again, PNGC's argument is based on the false premise that language in the contract "negates" the policy intent in AA7 regarding service to returning load. As pointed out previously, customers that diversified were given no PF rate assurance in the contract concerning which PF rate or rates would apply to serve previously uncommitted load when returned. In fact, the TACUL rate is an adjustment to the PF-96 rate. Kitchen *et al.*, WP-02-E-BPA-36, at 1. Thus, customers that return diversification load under the TACUL will pay the PF rate, plus the TACUL. *Id.* at 1. Rather than developing an entire new PF rate, BPA found that it was necessary to add a charge to the PF-96 rate in order to reflect the cost BPA incurs to serve returned incremental load. Kitchen *et al*., WP-02-E-BPA-50, at 9.

Decision

The diversification agreements between BPA and PNGC member cooperatives provide that BPA may elect to establish a separate or new "PF" rate.

19.3 Recall/Returning Diversification Loads

Issue 1

Whether BPA's refusal to recall surplus power sales to serve requirements load violates the Northwest Power Act.

Parties' Positions

PNGC argues that BPA claims to be deficit in order to impose a TACUL, then claims not to be deficit when it comes to refusing to exercise its recall rights in its extraregional contracts. PNGC Brief, WP-02-B-PN-01, at 14. PNGC claims that the use of market-based resources rather than FBS resources to serve the diversified customers' loads in August and September 2001 directly violates BPA's obligations to use FBS power that is readily available through recall provisions in BPA's extraregional power sales agreements. *Id*. NRU argues that, as a matter of law, if firm power is available, or if BPA could make it available by exercising rights to recall power, public agency customers are entitled to receive it based on their statutory rights as preference customers, and they should pay only a cost-based PF-96 rate. NRU Brief, WP-02-B-NI-02, at 28. OURCA states that if BPA has the option of exercising existing rights to recall power, the customers that are subject to the TACUL are entitled to receive the power at a cost-based PF-96 rate. OURCA Brief, WP-02-B-OU-01, at 6; OURCA Ex. Brief, WP-02-R-OU-01, at 6. PPC argues that BPA expects it will not have enough inventory to serve such PF loads, but that BPA does not plan to recall surplus Federal power sales to serve them despite approximately 180 aMW of recallable surplus sales available. PPC Brief, WP-02-B-PP-01, at 31; PPC Ex. Brief, WP-02-R-PP-01, at 7.

BPA's Position

While BPA does have a statutory obligation to include a right to recall surplus firm power sold or exchanged under extraregional contracts, as well as surplus firm power sold as replacement power in the region, BPA has determined that it is not necessary at this time to exercise that right. Kitchen *et al*., WP-02-E-BPA-50, at 7. On a planning basis, BPA has determined that it can meet all expected PNW customer requirements without having to exercise its rights to recall surplus firm power by purchasing in the market or relying on seasonal surplus firm power. *Id*.

Evaluation of Positions

PNGC, NRU, OURCA, and PPC argue that BPA is obligated by statute to recall surplus firm power sold under extraregional contracts to serve the returning uncommitted loads of preference customers at the PF-96 rate. There is no legal basis to support these parties' arguments, and none of them cites any statutory provisions that compel the result they seek.

PNGC refers to section 5(b) of the Northwest Power Act and section 4 of the Bonneville Project Act. PNGC Brief, WP-02-B-PN-01, at 13. Neither of these two sections contains language to support PNGC's argument. Section 5(b) of the Northwest Power Act establishes the manner by which BPA will offer power sales contracts to meet the net firm power load requirements of regional utilities. Section 4 of the Bonneville Project Act sets forth the general provisions entities seeking to qualify for preference and priority must comply with in order to purchase power on a preference basis from BPA.

OURCA cites to *Aluminum Company of America v. Central Lincoln Peoples' Utility District*, 467 U.S. 380, 391 (1984) to support its argument that BPA must exercise the recall rights included in the contracts of the non-preference customers in order to serve the firm power loads of the public preference customers. OURCA Brief, WP-02-B-OU-01, at 6. The case OURCA cites does not support its argument regarding the TACUL. To the contrary, the case OURCA relies on concerns the recall of interruptible power in contracts between BPA and its DSI customers. The current contracts with the DSI customers, however, are firm and cannot be interrupted. Section 5(b)(2) of the Northwest Power Act also requires that contracts with IOUs include the right of the Administrator to reduce her obligations in accordance with section 5(a) of the Bonneville Project Act. Section 5(a) requires that a five-year notice be given to IOUs if the Administrator determines that power sold under such contracts is necessary to meet the needs of preference customers. BPA is not required at this time to recall any power sold to IOUs, because BPA is not providing such power under existing contracts.

BPA's obligation under statute regarding recall of surplus firm power under extraregional power sales contracts arises under section 3(a) of the Regional Preference Act, 16 U.S.C. §837b(a). Section 3(a) provides in part:

> Any contract for the sale or exchange of surplus firm energy for use outside the PNW, or as replacement, directly or indirectly, within the Pacific Northwest for hydroelectric energy delivered for use outside the region by a non-Federal utility, shall provide that the Secretary, after giving the purchaser notice not in excess of 60 days, will not deliver electric energy under such contract whenever it can reasonably be foreseen that such delivery would impair his ability to meet, either at or after the time of such delivery, the energy requirements of any PNW customer.

16 U.S.C. §837b(a). Consistent with the law, the Administrator does not reasonably foresee that her ability to serve returning uncommitted load of customers subject to the TACUL is impaired because of sales of surplus firm power under extraregional contracts. The subsequent passage of the Transmission System Act and the Northwest Power Act grant BPA ample authority to acquire power to meet the Administrator's obligations under contract to serve load. As long as resources can be acquired and are available on a planning basis to meet BPA's load requirements, the Administrator can reasonably foresee that her ability to serve uncommitted load will continue unimpaired. Further, the exercise of the Administrator's right to recall surplus firm power under extraregional contracts is compelled to meet the Administrator's supply obligation only. Recall is not required to provide any customers a particular price.

PNGC argues that the Draft ROD ignores the prohibition against selling non-surplus power outside of the PNW, and ignores certain provisions in the Regional Preference Act that "inform and control Bonneville's ability to sell extraregional power." PNGC Ex. Brief, WP-02-R-PN-01, at 6-7. PNGC supports its position by arguing the following: the definition of the term "surplus energy" as defined in section 1(c) of the Regional Preference Act requires that the "extraregional contracts must only sell electric energy that, absent the extra regional sale, would be 'wasted' because there is a total lack of a market in the PNW for that energy 'at any established rate,'" *Id*. at 7; the returning utility load that is subject to TACUL is clearly an "energy requirements of any Pacific Northwest customer" as defined under section 837 of the Regional Preference Act, *Id*.; and, if there is a market in the PNW at "any established rate" for all of Bonneville's generating capability, then there is simply no surplus power and, thus, there can be no extraregional sales, *Id*. at 8.

PNGC misunderstands and misapplies this provision of law. Section 1(f) is a definitional provision. It defines what energy is surplus.

> "Surplus energy" means electric energy generated at Federal hydroelectric plants in the Pacific Northwest which would otherwise be wasted because of the lack of a market therefor in the Pacific Northwest at any established rate.

16 U.S.C. §837(c).

This definition places no limitations on BPA, it merely defines a type of power that BPA has the authority to market. Prior to BPA selling any surplus energy out of the region, BPA is required under section 2 of the Regional Preference Act to first offer it to its regional customers 30 days prior to the execution of an extraregional sale of surplus power. BPA is required to give notice to its customers of the pending sale. At the time that surplus firm power sales were made to purchasers outside the region, PNGC members, like all regional customers of BPA, received notice and had 30 days in which to purchase such power.

The Regional Preference Act does not give PNGC members, or other customers similarly situated, the right to now request specific sources of power for service when requested under section 5 of the Northwest Power Act. 16 U.S.C. §839c(b)(1). Sales of surplus firm power to purchasers outside the region are firm contractual obligations. *See, generally*, 16 U.S.C. §832d(a) ("[c]ontracts entered into under this subsection shall be binding in accordance with the terms thereof . . ."), 16 U.S.C. §837, and 16 U.S.C. §839c(f). The law grants BPA specific authority to make such sales. Section 5(f) of the Northwest Power Act states:

> The Administrator is authorized to sell, or otherwise dispose of, electric power, including power acquired pursuant to this and other Acts, that is surplus to [her] obligations incurred pursuant to subsection (b), (c), and (d) of this section in accordance with this and other Acts applicable to the Administrator, including the Bonneville Project Act . . ., the Federal Columbia River Transmission System Act . . ., and the Act of August 31, 1964 (16 U.S.C. §837-837h).

16 U.S.C. §839c(f).

Because these sales are firm obligations, the Regional Preference Act is clear in its language regarding the standard that must be met before the Administrator is obligated to exercise the right of recall. That right shall be exercised only "whenever it can reasonably be foreseen that such delivery would impair [her] ability to meet, either at or after the time of such delivery, the energy requirements of any Pacific Northwest customer." 16 U.S.C. §837b(a).

PNGC argues that nothing in either the Transmission Act or the Northwest Power Act "obviate, or in any way alter, the prohibition against selling extraregional power when there are markets for that power in the PNW." PNGC Ex. Brief, WP-02-R-PN-01, at 8. PNGC's argument is without basis in either statute. These statutes, contrary to PNGC's argument, authorize BPA to acquire power to meet its firm contractual obligations. Section 5(f) of the Northwest Power Act specifically authorizes BPA to enter into surplus power sales. Therefore, the Administrator's ability to meet the "energy requirements" of the PNGC members' returning uncommitted load is simply not impaired by sales of surplus firm power to extraregional purchasers, because BPA can acquire power under section 11(b)(6) of the Transmission Act, 16 U.S.C. §838i(b)(6), and section 6(a) of the Northwest Power Act, 16 U.S.C. §839d(a)(1)–839d(a)(2). BPA plans its market purchases to meet its total load obligation amounts, including PSW loads [Pacific Southwest, extraregional sales], on an annual basis to cover periods when it will not have sufficient critical period energy. Kitchen *et al*., WP-02-E-BPA-36, at 6. Under critical water conditions, power sold to serve load subject to the TACUL and power sold under extraregional contracts is power purchased from the market to meet total loads. *Id*.

The term "energy requirements" is defined in section 837(f) of the Northwest Preference Act as:

> [T]he full requirements for electric energy of: (1) any purchaser from the United States for direct consumption in the Pacific Northwest; and (2) any non-Federal utility in that region in excess of: (a) the hydroelectric energy available for its own use from its generating plants in the Pacific Northwest; and (b) any additional energy available for use in the Pacific Northwest which under a then existing contract, the utility (A) can obtain at no higher incremental cost than the rate charged by the United States; or (B) is required to accept.

16 U.S.C. §837(f).

This is a definitional section which applies to the Administrator's determination of "energy requirement." BPA does not disagree with PNGC that uncommitted load that is returned to BPA service is an energy requirement of the customer. BPA acknowledges its statutory obligation to serve this load. However, PNGC then claims "Bonneville is prohibited by section 837a [section 2] from selling extraregional energy when regional customers have a need for that energy." PNGC Ex. Brief, WP-02-R-PN-01, at 7. BPA is at a loss to find the statutory prohibition that PNGC is claiming exists in section 2. Neither the definition of "energy requirements" in section 1(f) nor section 2 contain language prohibiting BPA from making extraregional sales of surplus power.

Section 2 of the Regional Preference Act contains no prohibition on sales of surplus firm power to purchasers outside the region. As stated above, section 2 directs the Administrator to provide notice to regional customers of pending extraregional sales to allow BPA's regional customers the opportunity to purchase such power prior to sale outside the region. PNGC members were notified of pending sales of surplus firm power to extraregional purchasers. All such sales were duly noticed and executed in accordance with statute. Prior to the execution of these sales of surplus firm power, PNGC members had the right to purchase such power first. They declined. BPA is under no obligation now to recall the power sold under these contracts to meet the uncommitted load of its regional customers as long as the Administrator reasonably foresees that she is not impaired in her ability to meet their energy requirements.

PNGC argues that the Draft ROD is in error regarding the statement "[r]ecall is not required to provide any customers with a particular price." PNGC Ex. Brief, WP-02-R-PN-01, at 7, quoting the Draft ROD, WP-02-A-01, at 19-17. PNGC claims that "the definition of 'surplus energy' makes it clear that surplus energy is energy that cannot be sold in the PNW 'at any established rate.'" *Id*. at 8. PNGC adds that "[i]f there is a market in the PNW 'at any established rate' for all of BPA's generating capability, then there is simply no surplus power. If there is no surplus power there can be no extra regional sales." *Id*. This argument is also misplaced. PNGC misreads the definition of "surplus energy" under the Regional Preference Act. Prior to its being offered as surplus power under contract, BPA must first determine that such power is surplus by first offering it to regional customers at any established rate. Once BPA has done this, and no regional customers elect to purchase, then such power can be sold to purchasers outside the region as surplus power. Nothing in the language of the Regional Preference Act obligates the Administrator to recall surplus firm power sales to extraregional purchasers in order to provide any customers with a particular price. Notwithstanding the existence of a market for Federal power at established rates, the Administrator is not compelled to discontinue existing extraregional sales of surplus power to sell power to regional customers. The obvious import of the situation described by PNGC is there may be no surplus firm power currently available on a long-term basis which the Administrator may offer to purchasers outside the region. However, the obligation to recall surplus firm power already being sold extraregionally arises only when the Administrator reasonably foresees that her ability to meet the energy requirements of a PNW customer will be impaired. This is not the case.

To summarize, as in all the above arguments regarding BPA's obligation to exercise its right to recall surplus firm power, PNGC speciously argues that BPA is prohibited from continuing such sales if uncommitted load is returned to PF service. As BPA has stated several times, there simply is no prohibition in statute barring BPA from continuing such sales. The Administrator has the authority and the ability to acquire resources to serve the returning load. Because the Administrator's ability to meet this load is not impaired as a result of deliveries under contract of surplus firm power to extraregional purchasers, no recall of such power is required.

<u>Decision</u>

BPA's decision not to recall surplus power sales to serve requirements load is consistent with the directives of the Northwest Power Act. BPA has determined that it can meet all expected regional customer requirements without having to exercise its rights to recall power.

Issue 2

Whether BPA has been fully compensated for BPA's costs incurred due to diversification by some of its customers and will receive adequate revenue from other sources to compensate BPA for returning diversified loads.

Parties' Positions

PNGC makes several arguments that the TACUL is inappropriate, because BPA received "significant revenues" due to the payment by customers of exit fees to diversify and has already been fully compensated. PNGC Brief, WP-02-B-PN-01, at 15. PPC argues that BPA has not demonstrated any economic harm that it expects to bear as a result of serving these PF TACUL loads. PPC Brief, WP-02-B-PP-01, at 31. PNGC argues that the assertion made by PNGC and PPC panels remains unrefuted, that over the PF-96 rate period the revenues BPA received from exit fees and additional surplus sales (resulting from diversified load) will more than offset any additional costs BPA may incur if it chooses not to recall extraregional surplus sales. PNGC Brief, WP-02-B-PN-01, at 17.

BPA's Position

The TACUL is a prudent business decision that, as contemplated in the customer's contract, is needed to cover costs caused by an individual customer's exercise of a contract option that would otherwise have to be recovered from other customers. Kitchen *et al.*, WP-02-E-BPA-50, at 6. Exit fees were not designed to cover the costs of customers wanting to return diversified load to BPA service during the rate period. *Id*. The net revenue from both the long-term sales of surplus firm power to extraregional purchasers and the sales of firm power made surplus or excess to BPA's existing firm power obligations as a result of diversification benefits all of BPA's customers. *Id*. at 7. For this reason, BPA does not agree that these revenues should go to benefit one specific group of customers; but rather, the revenues should continue to benefit all customer classes. *Id*.

Evaluation of Positions

PNGC's witnesses argued that the TACUL is nothing more than a form of quadruple dipping. Sabala *et al*., WP-02-E-PN-06, at 6-7. PNGC claimed that BPA will have received revenues in four ways: exit fees paid by utilities to diversify; revenue BPA received from sales of surplus power resulting from diversification; money BPA will receive from the cost-based rate established in anticipation of serving returning loads; and TACUL. *Id*. BPA disagreed with PNGC's so-called quadruple characterization and rebutted each alleged dip. Kitchen *et al.*, WP-02-E-BPA-50, at 5-6.

PNGC and PPC argue that BPA has made no attempt to credit back the revenues BPA received from exit fees and from sales of surplus power to the PF class as a whole, or against unanticipated costs within the PF-96 rate period, or to the utilities responsible for those additional revenues. PNGC Brief, WP-02-B-PN-01, at 15; PPC Brief, WP-02-B-PP-01, at 32.

Similarly, they argue the benefits should be recognized on a PF-96 class and rate period basis as an offset to any costs BPA may incur in serving load returned within the 1996 rate period.

Exit fees were not designed to cover the costs of customers wanting to return diversified load to BPA service during the rate period. Kitchen *et al*., WP-02-E-BPA-50, at 5. In this respect, the only "benefit" covered by the payment of the exit fee was the right of the customer to remove load from BPA service. Prior to BPA's agreement to allow customers to pay an exit fee, most requirements customers of BPA were obligated to purchase most if not all of their wholesale electric power from BPA. Payment of an exit fee gave a customer the right to reduce its contract obligation to purchase from BPA, and it provided a way to help cover BPA's losses from such forgone sales. *Id*. at 5. BPA does not agree that these revenues should go to benefit one specific group of customers; but rather, the revenues should continue to benefit all customer classes. *Id.* BPA objects to PNGC's inference that the uncommitted load it wishes to return be served at a new PF rate that is at or below the existing PF rate. PNGC Brief, WP-02-B-PN-01, at 17. BPA does not agree that customers that elected to serve their uncommitted load with power purchased from other suppliers should benefit by shifting the risk of their individual decisions to BPA. Erosion of BPA's revenues to recover the purchase power cost to serve uncommitted load for the remaining rate period is unwarranted. Burns and Elizalde, WP-02-E-BPA-08, at 15.

PNGC argues that BPA's partial denial of "windfall" sales proves PNGC's claims that such sales occurred. PNGC Brief, WP-02-B-PN-01, at 16. PNGC states that at a minimum BPA should provide some evidence of the magnitude of those windfall sales in order to prevail on the claim that it is incurring "unrecoverable" costs due to the returned load of these diversifying customers. *Id*. PPC argues that revenues BPA obtains for the Federal power sales made in lieu of BPA's sale to the diversifying utility may offset potential economic harm. PPC Brief, WP-02-B-PP-01, at 32.

With the reduction of its firm power obligations and corresponding revenues, BPA began sales of what was then surplus firm power. Kitchen *et al*., WP-02-E-BPA-50, at 4. PNGC's claim that BPA made a partial denial regarding whether or not surplus firm power sales resulted in a "large revenue windfall," PNGC Brief, WP-02-B-PN-01, at 16; is irrelevant. However, any revenue increase that BPA might experience will go to increase starting reserves and thereby benefit all customers in the next rate period. Nor is BPA compelled to offset the potential economic harm that customers subject to the TACUL may face, as suggested by PPC. PPC Brief, WP-02-B-PP-01, at 32. PNGC and PPC misunderstand the purpose of the TACUL. The cost of the TACUL will be based on BPA's costs to replace the FBS to serve the specific uncommitted load the customer wishes to return to PF service. *Id*. at 10. Because these loads are returning to BPA service, they are an additional load to the base 1996 rates and require additional FBS resources. *Id*. Since these loads can be identified as loads in addition to the customer's load that BPA is already obligated to serve during the 1996-2001 rate period, the costs incurred to serve such additional load can be identified. *Id*. BPA will base the cost to serve these additional loads on the costs that BPA will incur to serve the additional load. *Id*.

Decision

It is not relevant to BPA's imposition of the TACUL whether BPA was fully compensated for costs incurred due to diversification by some of its customers or whether BPA will receive adequate other sources of revenue to compensate BPA for returning diversified loads.

19.4 Equity

Issue 1

Whether BPA should eliminate the TACUL for reasons of equity.

Parties' Position

PNGC raises a new "equity" argument in its brief on exceptions. PNGC Ex. Brief, WP-02-R-PN-01, at 2. PNGC argues that there is an equitability rationale for rejecting TACUL. *Id*. PNGC contends customers who diversified were under the "legitimately held" belief that BPA would apply either the PF-96 rate to returned load, or that BPA would apply a PF-type of rate that was set using embedded cost ratemaking principles and BPA's then current financial and load data. *Id*.

BPA's Position

This is a new argument. PNGC essentially pieces together its new argument from fragments of its argument made in its initial brief. Although the Draft ROD addressed these issues as separate arguments, BPA will address them here as one.

Evaluation of Positions

PNGC states that diversified customers were informed that the returned load would be served at a PF rate. PNGC Ex. Brief, WP-02-R-PN-01, at 2. That promise is codified in the contracts BPA signed which allowed for diversification in the first place. *Id*. PNGC is correct that customers wishing to return uncommitted load to BPA will be served with a PF rate--the PF-96 rate plus a PF adjustment rate called the TACUL. As the Draft ROD states, "customers who diversify and wish to reestablish service will not get the PF rate available to the loads which stayed with BPA, but will pay the full incremental cost associated with providing that service, as set through a 7(i) process." Draft ROD, WP-02-A-01, at 19-5, quoting the Administrator's ROD on AA7 and Contract Templates, at 10. Consistent with the AA7 ROD, the AA7 and new contracts contain the following language: "BPA may elect to establish a separate PF rate or rates for power used to serve that portion of [the customer's] loads" returned to PF service. *See* PNGC Brief, WP-02-B-PN-01, at 11; WP-02-E-PN-14.

PNGC contends that the Draft ROD dismisses the fact that BPA's own contract calls for a PF rate, characterizing it as mere "semantics." PNGC Ex. Brief, WP-02-R-PN-01, at 2, citing the Draft ROD, WP-02-A-01, at 19-15. PNGC misconstrues the Draft ROD. BPA's Draft ROD at 19-15 responds to the argument made by PNGC in its initial brief that its members' contract as amended provides that BPA may elect a "new PF rate." PNGC Brief, WP-02-B-PN-01, at 12. PNGC argued that BPA violates the "explicit restriction" contained in BPA's contracts with the diversifying customers by attempting to establish a market rate (the TACUL) that is not an embedded-cost based PF rate. *Id*. There is no restriction in the contract, and it is mere semantics that PNGC relies upon to imply one. The Draft ROD states, "There is no basis to support PNGC's contention that there is a distinction to be drawn over the terms used in PNGC's members' contracts to describe the rate BPA has the right to establish. Whether the term used is 'separate PF rate or rates' or 'new PF rate,' the fact remains that if the load was uncommitted, the proposed TACUL will apply during the months of August and September 2001." Draft ROD, WP-02-A-01, at 19-5. BPA's position is unchanged.

PNGC contends that the meaning of a PF rate is that the rate would be set as have been all PF rates up to this point in time, based on BPA's then current financial goals and conditions and load estimates. PNGC Ex. Brief, WP-02-R-PN-01, at 2. PNGC asserts that "[t]his separate PF rate was expected to come in somewhere close to PF-96 and certainly below PF-02, given BPA's PBL's robust financial conditions and its revenue requirement for the 1996-2002 rate period (or even just its 2002 revenue requirement.)" *Id*. at 3. PNGC contends that diversifying utilities have a legitimately held belief, induced by BPA, that their returned load would in fact be served at a PF rate set in this manner. *Id.* PNGC's argument states its own expectation of what the TACUL would be. No doubt all parties to a section 7(i) proceeding have expectations of what any applicable rate they may be charged will be. PNGC claims that BPA induced diversified utilities into a belief regarding the manner in which the PF rate would be set. BPA denies that it induced any of its customers that diversified into any belief regarding the setting of the TACUL. The establishment of the TACUL is being subjected to the rigor of this section 7(i) proceeding. PNGC's expectation of the price of the TACUL, however, is not based upon demonstrable evidence in the record. The actual price of any TACUL that may be applied to a customer is presently unknown, since no TACUL has been applied. What has been proposed in this 7(i) is the methodology upon which the TACUL will be calculated at the time it applies. *See* Kitchen *et al*., WP-02-E-BPA-36, at 4. The TACUL will recover the additional cost of serving uncommitted customer load returned to requirements service. *Id*. at 2. The methodology of the proposed TACUL provides that if no incremental cost is incurred, then the customer will merely pay PF-96 with zero TACUL adjustment. *Id*. at 3.

PNGC asks the non-rhetorical question: "What then, is the purpose of returning load to an agency that will simply turn around and make market purchases to serve that load?" PNGC Ex. Brief, WP-02-R-PN-01, at 3. PNGC notes that its own members are making purchases in the market to serve their load before they had determined to return it to BPA. *Id*. PNGC argues that if the members of PNGC had known BPA would do the same, they would not have made the decision to return that load in the first place. *Id*. "The only explanation for their decision to return load to BPA is that they were operating under the BPA induced understanding that BPA would serve their load at a PF rate and not at a market rate." *Id*.

If this is truly a question for BPA to answer, it may be surmised that those utilities that diversified and made resource decisions to purchase power from resources or suppliers other than BPA, *i.e.,* the market, did so for economic gain. These were independent decisions. They have also independently chosen to return uncommitted load to BPA for service. However, it has not been promised by BPA that upon return such load would be served with the same available PF rate as those customers who did not take load off of BPA. *See* Draft ROD, WP-02-A-01, at 19-5, quoting the Administrator's ROD on AA7 and Contract Templates, at 10. Such load has, since becoming uncommitted, faced a rate uncertainty if returned to BPA service. PNGC is disingenuous in arguing that its members' uncommitted load will face a market rate when returned to BPA service. The fact is that most of PNGC's uncommitted load when returned will be served at the PF-96 rate without incurring the TACUL. This is because BPA determined at the time PNGC made its first request that it had sufficient availability of power at the PF-96 rate available to serve that portion of PNGC's uncommitted load, *i.e*. prior to December 7, 1998. *See* Draft ROD, WP-02-A-01, at 19-10. However, as more customers made requests to return diversified load, which increased the amount of power BPA would be obligated to supply, BPA took the prudent step to determine the availability of its supply on a planning basis. Kitchen *et al*., WP-02-E-BPA-50, at 8. Based on BPA's studies of its loads and resources, BPA determined the need to establish the TACUL. *Id*.

Finally, PNGC argues that BPA must examine its course of dealing with these utilities to decide not only what is legal but what is right and equitable. BPA has considered its dealings with customers that chose to diversify their resources and the load served by such resources. Some of these customers sued or threatened to sue BPA to get the right to purchase from other suppliers. They felt compelled to leave BPA when the market was attractive and its cost was less than BPA's PF rate. On the other hand, BPA is keenly aware of its statutory obligation to meet the net requirements of its public body and cooperative customers. As such, BPA will serve, but the cost of providing service to returning uncommitted load should be borne by such load. It is not equitable for those customers that stayed with BPA, who did not accept the benefits and risks of the market, to bear any of the cost associated with serving uncommitted loads.

Decision

BPA will not eliminate the TACUL for reasons of equity.

20.0 CONCLUSION

As required by law, the rates established and adopted in this ROD have been set to recover the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the FCRPS (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and all other costs and expenses incurred by the Administrator in carrying out the requirements of the Northwest Power Act and other provisions of law. In addition, these rates have been designed to be as low as possible consistent with sound business principles, to encourage the widest possible use of BPA's power, to equitably allocate the recovery of transmission costs between Federal and non-Federal users, and to satisfy BPA's other ratemaking obligations, including those contained in the Energy Policy Act of 1992. The Hearing Officer has assured that all interested parties and participants were afforded the opportunity for a full and fair evidentiary hearing, as required by law.

BPA must evaluate the proposed rates in a section 7(i) proceeding pursuant to the Northwest Power Act. BPA must also evaluate the potential environmental impacts of the proposed rate increases and alternatives thereto, as required by NEPA. In this instance, the environmental analysis provided by the Business Plan Final EIS details the environmental impacts of BPA's 2002 final power rate proposal. The environmental analysis contained in the Business Plan Final EIS has been considered in making the decisions in this ROD.

Based upon the record compiled in this proceeding, the decisions expressed herein, and all requirements of law, I hereby adopt the attached Wholesale Power Rate Schedules as Bonneville Power Administration's 2002 final power rate proposal. In accordance with Federal Energy Regulatory Commission Requirements, 18 C.F.R. section 300.10(g), the Administrator hereby certifies that the Wholesale Power Rate Schedules adopted herein are consistent with applicable laws and are the lowest possible rates consistent with sound business principles.

Issued at Portland, Oregon, this 10th day of May, 2000.

/s/ Judith Johansen
Administrator

ATTACHMENT

SLICE METHODOLOGY
(FOR FERC APPROVAL FOR 10 YEARS)

METHODOLOGY TO CALCULATE SLICE RATE AND SLICE TRUE-UP ADJUSTMENT CHARGE

Section 1. PURPOSE

The Slice Methodology is designed as a means for providing a consistent method of calculating the rate for Slice and conducting the annual true-up for 10 years of the contract. Because there is some uncertainty regarding the calculation of the Slice rate in a rate period subsequent to the FY 2002-2006 rate period, the Slice Methodology is intended to bring some stability to the calculation of the rate. The Slice Methodology is not intended to predetermine the actual rate a Slice purchaser will pay in any rate period; rather, the Slice Methodology proposes a set of cost categories that will make up the Slice Revenue Requirement and the manner in which such costs may be trued up annually.

Section 2. TERM OF THE METHODOLOGY

After FERC approval, this methodology shall take effect on October 1, 2001, and shall terminate on the earlier of midnight September 30, 2011, or a date established by FERC.

Section 3. DEFINITIONS

Actual Slice Revenue Requirement means the use of audited actual financial data in the cost categories comprising the Slice Revenue Requirement.

Capital Expenses means depreciation expense (recovery of the investment) and net interest expense (recovery of financing costs). 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 Table 1, Slice Product Costing and True-Up Table, unless BPA adopts a new depreciation study.

Contracted Loads for each five-year rate period shall be the average of five Fiscal Year (FY) loads contracted for in annual aMW for the Public Agency customers, DSI customers to be served with FBS resources, IOU customers to be served with FBS resources, and the Preexisting Multiyear Contracts that are known to BPA.

Forecasted Loads for each five-year rate period shall be the average of five forecasted FY loads in annual aMW that was included in the applicable Final Power Rate Proposal for the Public Agency loads, DSI loads to be served with FBS resources, IOU loads served with FBS resources, and Preexisting Multiyear Contracts.

Initial Implementation Expenses means the expenses of implementing the Slice product for which BPA was reimbursed, prior to October 1, 2001, pursuant to the Master Agreement to Enable the Technical Development of a Slice of System Power Sale (Master Agreement).

Minimum Required Net Revenues means the amount by which BPA's payments to the U.S. Treasury for generation amortization and irrigation assistance exceed the total non-cash expenses in the Actual Slice Revenue Requirement.

Preexisting Multiyear Contracts means BPA's contracts for power sales, which have been executed as of June 21, 1999, with a term length that extends beyond the first year of the FY 2002-2006 rate period.

Slice Revenue Requirement means the operating and Capital Expenses and credits included in the Slice Rate which are established in the generation Revenue Requirement Study for the applicable rate periods and are subject to the criteria for inclusion of new costs or credits. The costs and credit categories included in the Slice Revenue Requirement are listed in Table 1, Slice Product Costing and True-Up Table.

Slice System Resources means the FBS resources identified in the Slice contract.

System Obligations means those operational or contractual obligations of the FBS that are identified in the Slice contract.

Section 4. METHODOLOGY

A. Slice Rate Calculation

The monthly rate for the Slice product will be calculated in the following manner:

Monthly rate for the Slice product per 1 percent of the Slice System = (Annual Average Slice Revenue Requirement / 12) /100 where the Slice Revenue Requirement is calculated as described in section B below.

For the FY 2002-2006 rate period, the Slice Revenue Requirement will contain the costs and credits displayed in Table 1, Slice Product Costing and True-Up Table.

For the FY 2007-2011 rate period, the Slice Revenue Requirement will contain the costs and credits estimated in the FY 2007 rate case for the cost and credit categories identified in Table 1, Slice Product Costing and True-Up Table, and any other currently unidentified cost or credit, as described in section B. 3. below.

B. Slice Revenue Requirement

1. Uniform Application Throughout the Rate Period

The Slice Revenue Requirement is a five-year annual average amount for the applicable rate period. The Slice Rate will remain constant during the applicable rate period.

2. **Cost and Credit Categories Used to Set the Slice Revenue Requirement**

The cost and credit categories used to set the Slice Revenue Requirement and the Actual Slice Revenue Requirement shall be those defined in the generation Revenue Requirement Study for the 2002 Final Power Rate Proposal and listed in Table 1, Slice Product Costing and True-Up Table.

For FY 2002 only, the total of all Initial Implementation Expenses that BPA received under the Master Agreements shall be included in the Actual Slice Revenue Requirement.

3. **Inclusion of New Costs or Credits**

PBL costs or credits not otherwise specifically dealt with in the Slice Revenue Requirement, or excluded therefrom as specified in section B. 4. below, may be included in both the Slice Revenue Requirement and the Actual Slice Revenue Requirement, if and to the extent that:

Such PBL costs or credits could be properly includable in PBL's wholesale power rates; and either

a) Such PBL costs or credits are: (1) incurred by PBL to provide service to customers other than Slice purchasers; and (2) incurred to provide service to or otherwise benefit Slice purchasers;

OR

b) Such PBL costs or credits are not incurred to provide service to customers other than Slice purchasers, nor to provide service to or otherwise benefit Slice purchasers.

4. **Costs Excluded from the Slice Revenue Requirement**

Excluded costs include, but are not limited to the following:

- All transmission costs (other than those associated with the transmission of System Obligations and GTAs);
- All power purchase costs (with the exception of net Inventory Solution costs);
- All PNRR and hedging costs, with the exception of those hedging costs incurred to implement the forecasted Inventory Solution; and
- All costs not permitted to be included in the Slice Revenue Requirement as specified by section B. 3. above.

5. Credits

a. Systemwide Credits

Systemwide credits are any monetary credits that PBL forecasts to receive that are associated with the costs identified in the Slice Revenue Requirement. Systemwide credits shall be included in both the Slice Revenue Requirement and the Actual Slice Revenue Requirement as a credit. The credits include, but are not limited to:

- Credits from the U.S. Treasury for PBL's settlement payment to the Colville Tribe;
- Credits from the U.S. Treasury for section 4(h)(10)(c) of the Northwest Power Act;
- Credits from the U.S. Treasury for the FCCF; and
- Revenues BPA receives for meeting System Obligations (including revenues received for Congestion Management or PNCA transactions).

b. Transmission Surcharge

As provided for under separate rate and contract, BPA's TBL may impose a transmission surcharge on the Slice purchaser's use of the BPA transmission system. Any revenues received by the TBL pursuant to such surcharge will be credited to PBL's total Actual Slice Revenue Requirement, and will be reflected in the Slice purchaser's True-Up Adjustment. Repayment of such funds by the PBL to TBL, if any, shall be included in the Actual Slice Revenue Requirement.

c. Purchaser-Specific Credits and Other Contract Related Charges

All Slice purchaser-specific credits and other Slice purchaser-specific charges resulting from the implementation of the Slice contract shall be applied as an adjustment to the Slice True-Up Adjustment Charge for each specific Slice purchaser. The adjustment for credits and charges associated with the implementation of the Slice contract will be defined in the Slice contract.

6. Inapplicability of Cost Recovery Adjustment Clause and the Dividend Distribution Clause

Neither the Slice Rate nor the Slice True-up Adjustment Charge paid by Slice purchasers will be subject to the CRAC or the DDC identified in the GRSPs or any successor thereto.

7. Net Cost of the Inventory Solution

BPA has forecasted firm energy purchases that supplement the capability of FBS Resources (Inventory Solution) to meet the forecasted loads. The cost of the Inventory Solution shall be included in both the Slice Revenue Requirement and the Actual Slice Revenue Requirement on a net cost basis. The forecasted net cost of the Inventory Solution (NCIS) shall be calculated as: (1) the total expenses for the Inventory Solution; less (2) the total revenues for the sale of such power; both as projected by BPA. Since Slice purchasers bear the responsibility for their proportionate share of any loss of FBS resources or capability thereof, the Inventory Solution will not include such replacements. The forecasted net cost of the Inventory Solution to be included in the Slice Revenue Requirement for the FY 2002-2006 rate period is identified in Table 1. An additional adjustment is included in the Actual Slice Revenue Requirement that is based on the change in the magnitude of the Inventory Solution expressed in MW, the calculation of which is described in section C. 2. below.

C. Slice True-Up Adjustment Charge

The Slice True-Up Adjustment Charge is a monthly charge applied to the Slice product that is expressed in terms of dollars per percent Slice selected. The Slice True-Up Adjustment Charge consists of two components: (1) an Inventory Solution True-Up Adjustment that is calculated once for each rate period and is applied as a constant adjustment in each month of the rate period; and (2) the Annual Slice True-Up Adjustment that is calculated once each fiscal year and is applied to specific months of the fiscal year. The Slice True-Up Adjustment Charge for each month shall be calculated in the following manner:

$STUAC_M = (ISTU_R + ASTU_M)$

Where:

$STUAC_M$ is the Slice True-Up Adjustment Charge for month M of the rate period.

$ISTU_R$ is the Inventory Solution True-Up Adjustment for rate period R.

$ASTU_M$ is the portion of the Annual Slice True-Up Adjustment applicable for month M.

1. Annual Slice True-Up Adjustment

The Annual Slice True-Up Adjustment shall be calculated for each fiscal year as soon as independently audited actual financial data are available. As necessary, the Actual Slice Revenue Requirement shall include a Minimum Required Net Revenues component to ensure coverage of annual cash requirements. The Annual Slice True-Up Adjustment shall be calculated to be the annual Slice Revenue Requirement for the FY subtracted from the Actual Slice Revenue Requirement for such FY as shown in Attachment 1. The Annual Slice True-Up Adjustment shall be applied either as a one month credit (if the adjustment is negative) or as a three-month charge (if the adjustment is positive, and spread equally across the three months) following the month the Annual Slice True-Up Adjustment is calculated.

2. Inventory Solution True-Up Adjustment

The Inventory Solution True-Up Adjustment (ISTU) is calculated once during each rate period and is calculated in the following manner:

$ISTU_R = (CL_R - FL_R)/ ISMW_R * NCIS_R/12$

Where:

$ISTU_R$ is the Inventory Solution True-Up Adjustment for the rate period R.

CL_R is the annual average Contracted Loads for the rate period R.

FL_R is the annual average Forecasted Loads for the rate period R.

(CL_R-FL_R) cannot be a value less than zero.

$ISMW_R$ is the annual average MW associated with the Inventory Solution for the rate period R.

$NCIS_R$ is the annual average net cost of the Inventory Solution for the rate period R.

TABLE 1

Table 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**	**$ 1,375,894**	**$ 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	$ 17,953	$ 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	$ 15,450	$ 13,250	$ 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**

Table 1 (Continued)

	PBL Costs ($000)	2002-2006 Audited Actuals	A 2002 Projected	B 2003	C 2004	D 2005	E 2006	F TOTAL
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	$ 26,685	$ 26,685	$ 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 Trnfrs & 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								

		($000)
124		($000)
125	**Annual Slice Revenue Requirement**	**$ 1,703,316**
126	**Monthly Slice Revenue Requirement**	**$ 141,943**
127	**One Percent of Monthly Requirement**	**$ 1,419.43**
128		

Five Year Total **$ 8,516,581**

B o n n e v i l l e   P o w e r   A d m i n i s t r a t i o n
P o w e r   B u s i n e s s   L i n e

2002 Final Power Rate Proposal

Administrator's Record of Decision

Appendix 1: 2002 Wholesale Power Rate Schedules

WP-02-A-02
May 2000

2002 WHOLESALE POWER RATES
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Commonly Used Acronyms ii

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COMMONLY USED ACRONYMS

AANR	Actual Accumulated Net Revenues
AC	Alternating Current
ACME	Accelerated California Market Estimator
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
APA	Administrative Procedures Act
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
Draft Rod	Draft Record of Decision
DSI	DSI (only the DSI represented by Murphy under DS)
DSIs	Direct Service Industrial Customers
ECC	Energy Content Curve
EFP	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
IS	Southern Intertie
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 (1000 volts)
kW	Kilowatt (1000 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)
MVA	Megavar
MVAR	Megavoltamperes
MW	Megawatt (1 million watts)

MWh	Megawatthour
NCD	Non-coincidental Demand
NEC	Northwest Energy Coalition
NEEA	Northwest Energy Efficiency Alliance
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 Integration Transmission
NTP	Network Integration Transmission (rate) for 1981 Power Sale Contracts
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
NYMEX	New York Mercantile Exchange
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
RESEXRAM	Residential Exchange Rate Analysis Model
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
SCRA	Supplemental Contingency Reserve Adjustment
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

2002 WHOLESALE POWER RATE SCHEDULES

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2002 POWER RATE SCHEDULES

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SCHEDULE PF-02
PRIORITY FIRM POWER

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of Firm Power to be used within the Pacific Northwest (PNW). Priority Firm Power may be purchased by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers; for direct consumption; and for Construction, Test and Start-Up, and Station Service. Rates in this schedule are in effect beginning October 1, 2001, and are available for purchase under requirements Firm Power sales contracts for a three- or five-year period. The Slice Product is only available for public bodies and cooperatives. Utilities participating in the Residential Exchange Program under section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to the Residential Exchange Program. Utilities participating in settlement of the Residential Exchange Program may purchase Priority Firm Power pursuant to their Subscription settlement agreement. Rates under contracts that contain charges that escalate based on BPA's Priority Firm Power rates shall be based on the five-year rates listed in this rate schedule in addition to applicable transmission charges.

Sales under the PF Exchange Subscription rate will be delivered in equal hourly amounts over the rate period. The consumer bills of participating investor-owned utilities (IOU) should designate "Benefits of the Federal Columbia River Power System (FCRPS)" to describe the amount of benefits each consumer receives. Only the block product is available under this rate schedule.

This rate schedule supersedes the PF-96 rate schedule, which went into effect October 1, 1996. Sales under the PF-02 rate schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs). Products available under this rate schedule are defined in the 2002 GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's 2002 GRSPs and billing process.

For ease of reference BPA uses the term PF rate, and PF Preference rate interchangeably. For the PF Exchange rate, BPA clarifies which rate it is discussing by using either PF Exchange Program rate or PF Exchange Subscription rate.

SECTION II. RATES TABLES

The rates in this section apply to PF products. The PF Exchange Program rates and the PF Exchange Subscription rates are shown in Section III.

A. DEMAND RATE

1. Monthly Demand Rate for FY 2002 through FY 2006

1.1 Applicability

These rates apply to customers purchasing Firm Power for three or five years. These rates are also used to implement the Pre-Subscription Contracts.

1.2 Rate Table

Applicable Months	*Rate*
January	$2.16/kW-mo
February	$2.03/kW-mo
March	$1.82/kW-mo
April	$1.45/kW-mo
May	$1.43/kW-mo
June	$1.79/kW-mo
July	$2.31/kW-mo
August	$2.31/kW-mo
September	$2.31/kW-mo
October	$1.76/kW-mo
November	$2.31/kW-mo
December	$2.31/kW-mo

B. ENERGY RATE

1. Monthly Energy Rates for FY 2002 through FY 2004

1.1 Applicability

These rates apply to customers purchasing power in the first three years of the rate period.

1.2 Rate Table

Applicable Months	***HLH Rate***	***LLH Rate***
January	19.52 mills/kWh	13.54 mills/kWh
February	17.98 mills/kWh	12.54 mills/kWh
March	16.23 mills/kWh	10.82 mills/kWh
April	12.58 mills/kWh	8.22 mills/kWh
May	12.53 mills/kWh	6.65 mills/kWh
June	15.85 mills/kWh	8.20 mills/kWh
July	21.03 mills/kWh	14.09 mills/kWh
August	31.42 mills/kWh	17.33 mills/kWh
September	22.34 mills/kWh	18.19 mills/kWh
October	15.67 mills/kWh	11.16 mills/kWh
November	21.40 mills/kWh	17.11 mills/kWh
December	22.05 mills/kWh	16.77 mills/kWh

2. Monthly Energy Rates for FY 2005 through FY 2006

2.1 Applicability

These rates apply to purchases during the last two years of the rate period for customers purchasing for all five years of the rate period.

2.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	21.02 mills/kWh	15.04 mills/kWh
February	19.48 mills/kWh	14.04 mills/kWh
March	17.73 mills/kWh	12.32 mills/kWh
April	14.08 mills/kWh	9.72 mills/kWh
May	14.03 mills/kWh	8.15 mills/kWh
June	17.35 mills/kWh	9.70 mills/kWh
July	22.53 mills/kWh	15.59 mills/kWh
August	32.92 mills/kWh	18.83 mills/kWh
September	23.84 mills/kWh	19.69 mills/kWh
October	17.17 mills/kWh	12.66 mills/kWh
November	22.90 mills/kWh	18.61 mills/kWh
December	23.55 mills/kWh	18.27 mills/kWh

3. Monthly Energy Rates for FY 2002 through FY 2006

3.1 Applicability

These rates are used to implement the Pre-Subscription Contracts. These rates are also available to customers purchasing for all five years of the rate period under this rate table.

3.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	20.12 mills/kWh	14.14 mills/kWh
February	18.58 mills/kWh	13.14 mills/kWh
March	16.83 mills/kWh	11.42 mills/kWh
April	13.18 mills/kWh	8.82 mills/kWh
May	13.13 mills/kWh	7.25 mills/kWh
June	16.45 mills/kWh	8.80 mills/kWh
July	21.63 mills/kWh	14.69 mills/kWh
August	32.02 mills/kWh	17.93 mills/kWh
September	22.94 mills/kWh	18.79 mills/kWh
October	16.27 mills/kWh	11.76 mills/kWh
November	22.00 mills/kWh	17.71 mills/kWh
December	22.65 mills/kWh	17.37 mills/kWh

C. LOAD VARIANCE RATE

The Load Variance rate for FY 2002 through FY 2006 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section IV below. The rate for Load Variance is 0.8 mills/kWh.

D. SLICE RATE

1. Applicability

This rate is available to customers purchasing the Slice Product for the first five years of their Slice contract. This rate will remain constant during the five years of the rate period.

2. Rate

The monthly rate for the Slice Product is $1,419,430 per 1 percent of the Slice System.

SECTION III. PF EXCHANGE RATE TABLES

The rates in this section apply to sales under the Residential Exchange Program and the Subscription settlements of the Residential Exchange Program.

A. DEMAND RATE

1. Monthly Demand Rate for FY 2002 through FY 2006

1.1 Applicability

These rates apply to customers purchasing power for all five years of the rate period under the Residential Exchange Program and to customers purchasing power for all five years of the rate period under Subscription settlements of the Residential Exchange Program.

1.2 Rate Table

Applicable Months	***Rate***
January	$2.16/kW-mo
February	$2.03/kW-mo
March	$1.82/kW-mo
April	$1.45/kW-mo
May	$1.43/kW-mo
June	$1.79/kW-mo
July	$2.31/kW-mo
August	$2.31/kW-mo
September	$2.31/kW-mo
October	$1.76/kW-mo
November	$2.31/kW-mo
December	$2.31/kW-mo

B. ENERGY RATE

1. PF Exchange Program Energy Rates for FY 2002 through FY 2006

1.1 Applicability

These rates apply to customers purchasing power for all five years of the rate period under the Residential Exchange Program.

1.2 Rate Table

Applicable Months	*Energy Rate*
January	29.22 mills/kWh
February	27.18 mills/kWh
March	24.53 mills/kWh
April	19.47 mills/kWh
May	18.30 mills/kWh
June	22.84 mills/kWh
July	31.34 mills/kWh
August	44.27 mills/kWh
September	35.08 mills/kWh
October	24.18 mills/kWh
November	33.45 mills/kWh
December	33.95 mills/kWh

2. PF Exchange Subscription Energy Rates for FY 2002 through FY 2006

2.1 Applicability

These rates apply to eligible customers purchasing power under Subscription settlements of the Residential Exchange Program for all five years of the rate period.

2.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	20.12 mills/kWh	14.14 mills/kWh
February	18.58 mills/kWh	13.14 mills/kWh
March	16.83 mills/kWh	11.42 mills/kWh
April	13.18 mills/kWh	8.82 mills/kWh
May	13.13 mills/kWh	7.25 mills/kWh
June	16.45 mills/kWh	8.80 mills/kWh
July	21.63 mills/kWh	14.69 mills/kWh
August	32.02 mills/kWh	17.93 mills/kWh
September	22.94 mills/kWh	18.79 mills/kWh
October	16.27 mills/kWh	11.76 mills/kWh
November	22.00 mills/kWh	17.71 mills/kWh
December	22.65 mills/kWh	17.37 mills/kWh

C. LOAD VARIANCE RATE

The Load Variance rate for FY 2002 through FY 2006 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section IV.H below.
The rate for Load Variance is 0.8 mills/kWh.

SECTION IV.

The rates described above apply to the following:

Section IV.A.	Full Service Product
Section IV.B.	Actual Partial Service Product – Simple
Section IV.C.	Actual Partial Service Product – Complex
Section IV.D.	Block Product
Section IV.E.	Block Product with Factoring
Section IV.F.	Block Product with Shaping Capacity
Section IV.G.	Slice Product
Section IV.H.	Customers who purchase under the Residential Exchange Program or Subscription settlements of the Residential Exchange Program

1. PF Exchange Program Power
2. PF Exchange Subscription Power

A. FULL SERVICE PRODUCT

Purchases of the core Subscription Full Service Product are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Measured Demand on the Generation System Peak (GSP)
as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

B. ACTUAL PARTIAL SERVICE PRODUCT - SIMPLE

Purchases of the core Subscription Actual Partial Service Product – Simple are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
(the Purchaser's Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

C. ACTUAL PARTIAL SERVICE PRODUCT - COMPLEX

Purchases of the core Subscription Actual Partial Service Product – Complex are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
(the Purchaser's Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charges	II.I.
Flexible PF Rate Option	II.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

D. BLOCK PRODUCT

Purchases of the core Subscription Block Product are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Demand Entitlement
as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

E. BLOCK PRODUCT WITH FACTORING

Purchases of the core Subscription Block Product with Factoring are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
(the Purchaser's Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charges	II.I.
Flexible PF Rate Option	II.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

F. BLOCK PRODUCT WITH SHAPING CAPACITY

Purchases of the core Subscription Block Product with Shaping Capacity are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Demand Entitlement
as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

G. SLICE PRODUCT

Purchases of the Subscription Slice Product are limited to Public Preference Customers and are subject to the charges specified below.

1. Slice Product Charge

The charge for the Slice Product will be:
the elected Slice Percentage expressed as a decimal (.01 = 1%)
multiplied by
100
multiplied by
the Slice Rate in Section II.D.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Low Density Discount	II.Q.
Slice True-Up Adjustment	II.S.
Unauthorized Increase Charge	II.W.

H. CUSTOMERS WHO PURCHASE UNDER RESIDENTIAL EXCHANGE PROGRAM OR SUBSCRIPTION SETTLEMENTS OF THE RESIDENTIAL EXCHANGE PROGRAM

The PF Exchange rates include: (1) the PF Exchange Program rate; and (2) the PF Exchange Subscription rate.

1. Priority Firm Exchange Program Power

This PF Exchange Program rate applies to the traditional implementation of the Residential Exchange Program.

a. Priority Firm Exchange Program Power Charges

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Billing Demand, (which is calculated by applying the load factor, determined as specified in the Residential Exchange Program agreement, to the Billing Energy for each billing period)
multiplied by
the Demand Rate from Section III.A.

1.2 Energy Charge

The monthly charge for energy will be:
the Purchaser's Billing Energy, (which is the energy associated with the utility's residential load for each billing period computed in accordance with the provisions of the Purchaser's Residential Exchange Program agreement)
multiplied by
the Energy Rate from Section III.B.1.

1.3 Load Variance Charge

The charge for Load Variance is embedded in the energy charge.

b. Transmission Charges

Customers purchasing under this rate schedule are charged for transmission services under the Network Transmission (NT) rate schedule or its successor.

Customers purchasing under this rate schedule are charged for Load Regulation under the applicable charge established by the Transmission Business Line (TBL) or its successor.

c. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Low Density Discount	II.Q.

2. Priority Firm Exchange Subscription Power

This PF Exchange Subscription rate applies to sales under section 5(c) of the Northwest Power Act to IOUs that participate in a settlement of the Residential Exchange Program as described in BPA's Subscription Strategy.

a. Priority Firm Exchange Subscription Power Charges

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Contract Demand
multiplied by
the Demand Rate from Section III.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Contract Energy
multiplied by
the HLH Energy Rate from Section III.B.2.

(2) The Purchaser's LLH Contract Energy
multiplied by
the LLH Energy Rate from Section III.B.2.

1.3 Load Variance Charge

Not applicable.

b. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Green Energy Premium	II.N.
Unauthorized Increase Charge	II.W.

SECTION V. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule, except for the exchange product listed under Section IV.H.1.

SCHEDULE RL-02
RESIDENTIAL LOAD FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of Firm Power to be used within the Pacific Northwest. The Residential Load (RL) Firm Power Rate is available to investor-owned utilities (IOU) under net requirements contracts for resale to ultimate residential consumers for direct consumption. Further, in order to purchase under this rate, the 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. Each IOU will be able to purchase a specified amount of Firm Power at the RL-02 rate. Additional sales of requirements power to IOUs will be made at the NR-02 rate.

The product will be delivered in equal hourly amounts over the rate period. The consumer bills of participating IOUs should designate "Federal Columbia River Benefits Supplied By BPA" to describe the amount of benefits each consumer receives.

Rates in this schedule are available for purchases under requirements sales contracts for a five-year period. Only the block product is available under this rate schedule.

Sales under this schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs) and billing process.

SECTION II. RATES TABLES

The rates for the RL Firm Power product are identified below.

A. DEMAND RATE

1. Monthly Demand for FY 2002 through FY 2006

1.1 Applicability

These rates apply to eligible customers purchasing power for five years.

1.2 Rate Table

Applicable Months	*Rate*
January	$2.16/kW-mo
February	$2.03/kW-mo
March	$1.82/kW-mo
April	$1.45/kW-mo
May	$1.43/kW-mo
June	$1.79/kW-mo
July	$2.31/kW-mo
August	$2.31/kW-mo
September	$2.31/kW-mo
October	$1.76/kW-mo
November	$2.31/kW-mo
December	$2.31/kW-mo

B. ENERGY RATE

1. Monthly Energy Rates for FY 2002 through FY 2006

1.1 Applicability

These rates apply to eligible customers purchasing power for all five years of the rate period.

1.2 Rate Table

Applicable Months	***HLH Rate***	***LLH Rate***
January	20.12 mills/kWh	14.14 mills/kWh
February	18.58 mills/kWh	13.14 mills/kWh
March	16.83 mills/kWh	11.42 mills/kWh
April	13.18 mills/kWh	8.82 mills/kWh
May	13.13 mills/kWh	7.25 mills/kWh
June	16.45 mills/kWh	8.80 mills/kWh
July	21.63 mills/kWh	14.69 mills/kWh
August	32.02 mills/kWh	17.93 mills/kWh
September	22.94 mills/kWh	18.79 mills/kWh
October	16.27 mills/kWh	11.76 mills/kWh
November	22.00 mills/kWh	17.71 mills/kWh
December	22.65 mills/kWh	17.37 mills/kWh

C. LOAD VARIANCE RATE

Not applicable.

SECTION III. BILLING FACTORS AND ADJUSTMENTS

Eligible customers purchasing power under a contract implementing Subscription settlements of the Residential Exchange Program are subject to the charges specified below.

1. Residential Load Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Contract Demand
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):
(1) The Purchaser's HLH Contract Energy
multiplied by
the HLH Energy Rate from Section II.B; and
(2) The Purchaser's LLH Contract Energy
multiplied by
the LLH Energy Rate from Section II.B.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Green Energy Premium	II.N.
Unauthorized Increase Charge	II.W.

SECTION IV. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA's Power Business Line (PBL) and the customer negotiate otherwise at time of sale.

SCHEDULE NR-02
NEW RESOURCE FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of Firm Power to be used within the PNW. New Resource Firm Power (NR) is available to IOUs under net requirements contracts for resale to ultimate consumers; for direct consumption; and for Construction, Test and Start-Up, and Station Service. NR also is available to any public body, cooperative, or Federal agency to the extent such power is needed to serve any New Large Single Load (NLSL), as defined by the Northwest Power Act. That portion of the utility's load placed on BPA that is attributable to the NLSL will be billed under this rate schedule.

Rates in this schedule are available for purchases under contracts for which power deliveries begin on or after October 1, 2001 (2002 Contract), for a three- or five-year period. Products available under this rate schedule are defined in BPA's 2002 General Rate Schedule Provisions (2002 GRSPs).

This rate schedule supersedes the NR-96 rate schedule, which went into effect October 1, 1996. Sales under the NR-02 rate schedule are subject to BPA's 2002 GRSPs and billing process.

SECTION II. RATES TABLES

The rates in this section apply to NR products.

A. DEMAND RATE

1. Monthly Demand Rate for FY 2002 through FY 2006

1.1 Applicability

These rates apply to eligible customers purchasing power for three or five years.

1.2 Rate Table

Applicable Months	*Rate*
January	$2.16/kW-mo
February	$2.03/kW-mo
March	$1.82/kW-mo
April	$1.45/kW-mo
May	$1.43/kW-mo
June	$1.79/kW-mo
July	$2.31/kW-mo
August	$2.31/kW-mo
September	$2.31/kW-mo
October	$1.76/kW-mo
November	$2.31/kW-mo
December	$2.31/kW-mo

B. ENERGY RATE

1. Monthly Energy Rates for FY 2002 through FY 2004

1.1 Applicability

These rates apply to eligible customers purchasing power in the first three years of the rate period.

1.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	40.87 mills/kWh	28.97 mills/kWh
February	37.79 mills/kWh	26.97 mills/kWh
March	34.32 mills/kWh	23.55 mills/kWh
April	27.06 mills/kWh	18.37 mills/kWh
May	26.95 mills/kWh	15.25 mills/kWh
June	33.56 mills/kWh	18.33 mills/kWh
July	43.86 mills/kWh	30.06 mills/kWh
August	64.54 mills/kWh	36.50 mills/kWh
September	46.48 mills/kWh	38.22 mills/kWh
October	33.21 mills/kWh	24.23 mills/kWh
November	44.60 mills/kWh	36.07 mills/kWh
December	45.90 mills/kWh	35.39 mills/kWh

2. Monthly Energy Rates for FY 2005 through FY 2006

2.1 Applicability

These rates apply to purchases during the last two years of the rate period for eligible customers purchasing for all five years of the rate period.

2.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	42.37 mills/kWh	30.47 mills/kWh
February	39.29 mills/kWh	28.47 mills/kWh
March	35.82 mills/kWh	25.05 mills/kWh
April	28.56 mills/kWh	19.87 mills/kWh
May	28.45 mills/kWh	16.75 mills/kWh
June	35.06 mills/kWh	19.83 mills/kWh
July	45.36 mills/kWh	31.56 mills/kWh
August	66.04 mills/kWh	38.00 mills/kWh
September	47.98 mills/kWh	39.72 mills/kWh
October	34.71 mills/kWh	25.73 mills/kWh
November	46.10 mills/kWh	37.57 mills/kWh
December	47.40 mills/kWh	36.89 mills/kWh

3. Monthly Energy Rates for FY 2002 through FY 2006

3.1 Applicability

These rates apply to eligible customers purchasing for all five years of the rate period under this rate table.

3.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	41.47 mills/kWh	29.57 mills/kWh
February	38.39 mills/kWh	27.57 mills/kWh
March	34.92 mills/kWh	24.15 mills/kWh
April	27.66 mills/kWh	18.97 mills/kWh
May	27.55 mills/kWh	15.85 mills/kWh
June	34.16 mills/kWh	18.93 mills/kWh
July	44.46 mills/kWh	30.66 mills/kWh
August	65.14 mills/kWh	37.10 mills/kWh
September	47.08 mills/kWh	38.82 mills/kWh
October	33.81 mills/kWh	24.83 mills/kWh
November	45.20 mills/kWh	36.67 mills/kWh
December	46.50 mills/kWh	35.99 mills/kWh

C. LOAD VARIANCE RATE

The Load Variance rate for FY 2002 through FY 2006 is applicable to all customers purchasing power under this rate schedule unless specifically excluded in Section III below. The rate for Load Variance is 0.8 mills/kWh.

SECTION III. BILLING FACTORS, AND ADJUSTMENTS FOR EACH NR PRODUCT

This rate schedule contains seven subsections, corresponding to the products to which this rate schedule applies. The following seven products are available to serve NLSLs, or other loads served at the NR-02 rate.

Section III.A.	New Large Single Load
Section III.B.	Full Service Product
Section III.C.	Actual Partial Service Product - Simple
Section III.D.	Actual Partial Service Product - Complex
Section III.E.	Block Product
Section III.F.	Block Product with Factoring
Section III.G.	Block Product with Shaping Capacity

A. NEW LARGE SINGLE LOAD (NLSL) SERVICE PRODUCT

Purchases of New Resource Firm Power to serve a NLSL are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the NLSL's Demand Entitlement as
specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2), unless BPA and the Purchaser agree to bill based on a contract amount of energy.

(1) The NLSL's HLH Energy Entitlement as
specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) the NLSL's LLH Energy Entitlement as
specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be
the NLSL's Measured Energy for the billing period as specified in the contract
multiplied by
the Load Variance Rate from Section II.C.

If the customer is already paying the Load Variance Charge on the NLSL load through this or another rate schedule, this charge does not apply.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

B. FULL SERVICE PRODUCT

Purchases of the core Subscription Full Service Product are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Measured Demand on the GSP as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

C. ACTUAL PARTIAL SERVICE PRODUCT - SIMPLE

Purchases of the core Subscription Actual Partial Service Product – Simple are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
(the Purchaser's Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as
specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as
specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

D. ACTUAL PARTIAL SERVICE PRODUCT - COMPLEX

Purchases of the core Subscription Actual Partial Service Product – Complex are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
(the Purchaser's Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charges	II.I.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

E. BLOCK PRODUCT

Purchases of the core Subscription Block Product are subject to the charges specified below.

1. New Resource Firm Power

1.1. Demand Charge

The charge for Demand will be:
the Purchaser's Demand Entitlement as
specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2. Energy Charge

The total monthly charge for energy shall be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as
specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as
specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

F. BLOCK PRODUCT WITH FACTORING

Purchases of the core Subscription Block Product with Factoring are subject to the charges specified below.

1. New Resource Firm Power

1.1. Demand Charge

The charge for Demand will be:
(the Purchaser's Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2. Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charges	II.I.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

G. BLOCK PRODUCT WITH SHAPING CAPACITY

Purchases of the core Subscription Block Product with Shaping Capacity are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser’s Demand Entitlement as
specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser’s HLH Energy Entitlement as
specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser’s LLH Energy Entitlement as
specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below:

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

SECTION IV. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA's PBL and the customer negotiate otherwise at time of sale. Regulation and Frequency Response may have to be purchased for NLSLs.

IP-02
INDUSTRIAL FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available, in conjunction with the Industrial Firm Power Targeted Adjustment Charge (IPTAC), to BPA's direct service industrial customers (DSI) for Firm Power to be used in their industrial operations. DSIs that purchase power under contracts for which power deliveries begin on October 1, 2001 (2002 Contracts), are eligible to purchase under this rate schedule for a five-year period.

This rate schedule supersedes the IP-96 rate schedule, which went into effect October 1, 1996. Sales under the IP-02 rate schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs) and billing process.

SECTION II. RATES TABLES

The rates for the Industrial Firm Power (IP) product are identified below.

A. DEMAND RATE FOR ALL IP/IPTAC PRODUCTS

1. Flat Rate Demand for FY 2002 through 2006

1.1 Applicability

These rates apply to eligible customers purchasing power.

1.2 Rate Table

Applicable Months	***Rate***
January	$2.16/kW-mo
February	$2.03/kW-mo
March	$1.82/kW-mo
April	$1.45/kW-mo
May	$1.43\kW-mo
June	$1.79/kW-mo
July	$2.31/kW-mo
August	$2.31/kW-mo
September	$2.31/kW-mo
October	$1.76/kW-mo
November	$2.31/kW-mo
December	$2.31/kW-mo

B. ENERGY RATE

1. Monthly Energy Rates for FY 2002 through FY 2006

1.1 Applicability

These energy rates are to be combined with one of the two IPTACs specified in section 2.2 or 3.2 below.

1.2 Rate Table

Applicable Months	***HLH Rate***	***LLH Rate***
January	21.86 mills/kWh	15.88 mills/kWh
February	20.31 mills/kWh	14.88 mills/kWh
March	18.57 mills/kWh	13.16 mills/kWh
April	14.92 mills/kWh	10.55 mills/kWh
May	14.86 mills/kWh	8.98 mills/kWh
June	18.18 mills/kWh	10.53 mills/kWh
July	23.36 mills/kWh	16.43 mills/kWh
August	33.76 mills/kWh	19.66 mills/kWh
September	24.68 mills/kWh	20.53 mills/kWh
October	18.01 mills/kWh	13.50 mills/kWh
November	23.74 mills/kWh	19.45 mills/kWh
December	24.39 mills/kWh	19.11 mills/kWh

2. Monthly Energy Rates for FY 2002 through FY 2006 for IPTAC (A)

2.1 These rates apply to eligible customers purchasing power under this rate schedule.

2.2 A charge of 2.02 mills shall be added to each IP energy rate in the Rate Table in section 1.2 above.

3. Monthly Energy Rates for FY 2002 through FY 2006 for IPTAC (B)

3.1 These rates apply to eligible customers purchasing power under this rate schedule.

3.2 A charge of 3.52 mills shall be added to each IP energy rate in the Rate Table in section 1.2 above.

C. LOAD VARIANCE RATE

The Load Variance rate for FY 2002 through FY 2006 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section III below. The rate for Load Variance is 0.8 mills/kWh.

SECTION III. BILLING FACTORS AND ADJUSTMENTS FOR THE IPTAC PRODUCT

Only the firm take-or-pay Block Product is available under this rate schedule. Energy charges for the IPTAC product would apply as specified in Sections II.B.2. and II.B.3.

SECTION III.A. DSI Customers Who Purchase Under 2002 Industrial Firm Power Targeted Adjustment Charge (IPTAC) Contracts.

A. DSI CUSTOMERS WHO PURCHASE UNDER 2002 INDUSTRIAL FIRM POWER TARGETED ADJUSTMENT CHARGE (IPTAC) CONTRACTS

Purchases of power under a 2002 IPTAC contract are subject to the charges specified below.

1. Industrial Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Demand Entitlement as specified in the contract
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below:

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewable Discount	II.A.
Cost-Based Indexed IP Rate	II.C.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible IP Rate Option	II.K.
Green Energy Premium	II.N.
Industrial Firm Power Targeted Adjustment Charge	II.P.
Rate Melding	II.R.
Supplemental Contingency Reserves Adjustment	II.U.
Unauthorized Increase Charge	II.W.

SECTION IV. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA's PBL and the customer negotiate otherwise at time of sale.

NF-02
NONFIRM ENERGY RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of nonfirm energy to be used both inside and outside the United States including sales under the Western Systems Power Pool (WSPP) agreements and sales to consumers. The offer of nonfirm energy under this schedule shall be determined by BPA.

This rate schedule supersedes the NF-96 schedule, which went into effect on October 1, 1996. Sales under the NF-02 rate schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's 2002 GRSPs and billing process.

SECTION II. RATES, BILLING FACTORS, AND ADJUSTMENTS

The average cost of nonfirm energy is 25.18 mills/kWh. The NF-02 rate schedule provides for upward and downward pricing flexibility from this average nonfirm energy cost.

A. RATES FOR NONFIRM ENERGY

1. Standard Rate

The Standard rate is any offered rate not to exceed 30.22 mills/kWh.

2. Market Expansion Rate

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

3. Incremental Rate

The Incremental Rate is the Incremental Cost of energy plus 2.00 mills/kWh, where the Incremental Cost is defined as all identifiable costs (expressed in mills/kWh) that BPA would have avoided had it not produced or purchased the energy being sold under this rate.

4. Contract Rate

The Contract Rate is 25.18 mills/kWh.

B. BILLING FACTOR FOR NONFIRM ENERGY

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

C. ADJUSTMENTS FOR NONFIRM ENERGY

All adjustments are described in the 2002 GRSPs. The applicable sections are identified for each adjustment.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Cost Contributions	II.E.
Unauthorized Increase Charge	II.W.

SECTION III. DETERMINATION OF THE APPLICABLE NF RATE

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

A. STANDARD RATE

The Standard rate is available for all purchases of nonfirm energy.

B. MARKET EXPANSION RATE

1. Application of the Market Expansion Rate

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

2. Market Expansion Rate Qualification Criteria

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

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

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

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

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

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

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

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

3. Eligibility Criteria for Market Expansion Rate

a. When only one Market Expansion rate is offered:

Purchasers satisfying the Market Expansion Rate Qualifying Criteria specified in Section III.B.2 above, who purchased nonfirm energy directly from BPA, are eligible to purchase power under the Market Expansion rate offered if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.00 mills/kWh.

Purchasers qualifying under Section III.B.2 who purchase nonfirm energy through a third party are eligible to purchase power under the Market Expansion rate offered if the cost of the qualifying alternative fuel source is lower than the Standard rate in effect plus 4.00 mills/kWh.

b. When more than one Market Expansion rate is offered:

Purchasers qualifying under Section III.B.2 who purchase nonfirm energy directly from BPA are eligible to purchase power under the Market Expansion rate if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.00 mills/kWh. The rate applicable to a purchaser will be the highest Market Expansion rate offered that is below the purchaser's qualifying decremental cost *minus* 2.00 mills/kWh.

C. INCREMENTAL RATE

The Incremental rate applies to sales of energy:

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

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

3. that has an Incremental Cost greater than the Standard rate (plus the Intertie Charge, if applicable) minus 2 mills.

D. CONTRACT RATE

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

1. for sale of nonfirm energy; or

2. for determining the value of energy.

E. WESTERN SYSTEMS POWER POOL TRANSACTIONS (WSPP)

BPA may make available nonfirm energy for transactions under the WSPP agreement. WSPP sales shall be subject to the terms and conditions specified in the WSPP agreement and will be consistent with regional and public preference. The rate for transactions under the WSPP agreement is any rate within the limits specified by the Standard, Market Expansion, and Incremental rates but may not exceed the maximum rate specified in the WSPP agreement. The rate for WSPP sales may differ from the actual rate offered for non-WSPP transactions in any hour. The rate for WSPP transactions is independent of any other rate offered concurrently under this rate schedule outside the agreement.

F. END-USER RATE

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

SECTION IV. DELIVERY

A. RATE OF DELIVERY

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

B. GUARANTEED DELIVERY

1. Availability

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

2. Conditions

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

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

b. when BPA must reduce nonfirm energy deliveries in order to serve firm loads.

SECTION V. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA's PBL and the customer negotiate otherwise at time of sale.

BPA’S 2002

GENERAL RATE SCHEDULE PROVISIONS

FOR POWER RATES

INDEX

GENERAL RATE SCHEDULE PROVISIONS

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GENERAL RATE SCHEDULE PROVISIONS

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

A. Approval of Rates

These 2002 Wholesale Power Rate Schedules and General Rate Schedule Provisions (2002 GRSPs) shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (FERC). BPA has requested that FERC make these rates and 2002 GRSPs effective on October 1, 2001. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

These 2002 Wholesale Power Rate Schedules and the 2002 GRSPs associated with these schedules supersede BPA's 1996 rate schedules (which became effective October 1, 1996) to the extent stated in the Availability section of each rate schedule. These schedules and 2002 GRSPs shall be applicable to all BPA contracts, including contracts executed both prior to, and subsequent to, enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). All sales under these rate schedules are subject to the following acts as amended: The Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Transmission System Act (P.L. 93-454), the Northwest Power Act (P.L. 96-501), and the Energy Policy Act of 1992 (P.L. 102-486).

These 2002 rate schedules do not supersede any previously established rate schedule which is required, by agreement, to remain in effect.

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

C. Payment Provisions

Payment must be received by the 20th day after the issue date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or Federal holiday, the Due Date is the next business day. A late payment charge shall be applied each day to any unpaid balance. The late payment charge is calculated by dividing the applicable "Prime Rate" (reported in the "Money Rates" Section of the Wall Street Journal) plus 4 percent; by 365. The applicable "Prime Rate" shall be the rate reported on the first day of the month in which payment is received. The customer shall pay by electronic funds transfer using BPA's established procedures.

D. Notices

For the purpose of determining elapsed time from receipt of a notice applicable to rate schedule and GRSPs administration, a notice shall be deemed to have been received at 0000 hours on the first calendar day following actual receipt of the notice.

E. Provision for Reassignment of Surplus Transmission Capacity

PBL may reassign transmission capacity that it has reserved for its own use at a price not to exceed the highest of: (1) the original transmission rate paid by PBL; or (2) the applicable transmission provider's maximum stated firm transmission rate on file at the time of the transmission reassignment. Except for the price, the terms and conditions under which the reassignment is made shall be the terms and conditions governing the original grant by the transmission provider. Transmission capacity may only be reassigned to a customer eligible to take service under the transmission provider's open access transmission tariff or other transmission rate schedules.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. Conservation and Renewables Discount (C&R Discount)

1. Description of the Discount

To encourage and support the development of conservation projects and renewable resources in the PNW, BPA is offering a C&R Discount to customers purchasing under the Priority Firm Power (PF-02), New Resource Firm Power (NR-02), and Residential Load (RL-02) rate schedules. Purchasers of the Slice product and benefits provided as a cash payment in settlement of the Residential Exchange Program will also be eligible for the C&R Discount.

Customers purchasing under the Industrial Firm Power rate (IP-02) will be eligible to the extent that the C&R Discount does not reduce their effective rate below the DSI floor rate. Regional public agency customers with Pre-Subscription contracts with collared pricing provisions may be eligible for the C&R Discount subject to contract provisions.

The amount of the C&R Discount will be a fixed monthly amount based on the customer's forecasted purchases and Residential Exchange Program settlement benefits from BPA under its Subscription contract. Following the end of the Discount Period (which is the end of the rate period or the customer's contract term, whichever comes first), BPA will evaluate the customer's investments in qualifying conservation and renewable resource projects during the Discount Period. Any customer that has not spent at least as much money on Qualifying Expenditures as the cumulative C&R Discount received from BPA must reimburse the difference to BPA.

Purchasers accepting the monthly C&R Discount agree to abide by the implementation provisions specified in the C&R Discount Implementation Manual.

2. Calculation and Application of the Discount

a. Overview of the Discount

The C&R Discount will be included as a fixed dollar credit in the monthly power bill of each participating customer. The credit will equal the customer's forecasted average monthly Subscription Power Purchases and settlement benefits (in kWh) multiplied by the Unit Discount. (Because the average contract is used, the Unit Discount does not vary by month).

b. **Determination of the "Unit Discount"**

The Unit Discount will equal 0.50 mills/kWh for Subscription Power Purchases and settlement benefits. The Unit Discount for eligible Pre-Subscription contracts will be determined based on individual contract provisions.

c. **Determination of Individual Customer Discounts**

For a participating customer buying power from BPA, the monthly dollar discount will be determined by multiplying the customer's forecasted average monthly Subscription Power Purchases and settlement benefits for each contract year by the Unit Discount.

d. **Determination of Subscription Power Purchases**

1. To determine each customer's average monthly Subscription Power Purchase, BPA will use the customer's Net Requirements purchase, as established in the customer's Subscription contract to calculate the following:

   i. When a customer's contract explicitly calculates Net Requirements purchases for a contract year, the customer's monthly average Subscription Power Purchases are equal to the total annual Net Requirements purchases divided by 12.

   ii. When a customer's contract specifies only the monthly kWh output of the customer's resources, the customer must provide its Account Executive with a monthly load forecast of its Net Requirements purchases. The customer's total annual Net Requirements purchases will then be estimated, for purposes of applying the C&R Discount, by subtracting the customer's forecasted total annual resource output from its forecasted annual Requirements purchases and dividing the result by 12.

2. BPA shall treat benefit amounts provided as cash in settlement of Residential Exchange Program as described in their Subscription settlement contract as Subscription Power Purchases for purposes of this calculation.

e. **Annual Review of Individual Customer Discounts**

At least 30 days prior to the start of each contract year, customers will submit, to their Account Executive, adjustments to the monthly Subscription Power Purchase amounts, referred to in section 2 d. above, as specified in their BPA contract. Subscription Power Purchase increases or decreases of greater than 5 percent, year-to-year, will be reflected in the monthly C&R Discount amounts consistent with section 2 c., above.

f. **Application of the Discount**

i. The C&R Discount will be applied after BPA has determined all other charges and credits on the participating customer's power bill.

ii. BPA will provide the C&R Discount even in those months when the C&R Discount amount is larger than the customer's total power bill amount.

3. Qualifying Expenditures

a. Participating customers shall record all individual Qualifying Expenditures by the categories required for the Final Reconciliation Report to ensure full credit for their conservation and renewable resource activities. Qualifying Expenditures are those that meet technical standards developed by the Regional Technical Forum as approved by BPA.

b. Although BPA will provide the credit on a monthly basis, the customer has no obligation to adhere to any particular expenditure pattern. To retain the full C&R Discount provided by BPA, the participating customer must make Qualifying Expenditures during the Discount Period in an amount equal to, or exceeding, the cumulative C&R Discount received from BPA during the Discount Period.

4. Reporting

a. **Interim Conservation and Renewable Reports**

Participating customers shall submit to BPA annual Interim Conservation and Renewable Reports at the end of each fiscal year of the rate period (*i.e.*, 10/01/01 to 9/30/02, 10/01/02 to 9/30/03, etc.).

The Interim Report shall show the customer's cumulative C&R Discounts received to date and their annual and cumulative Qualifying Expenditures by category. If the report shows that the customer's Qualifying Expenditures are less than or equal to its cumulative C&R Discount receipts by 5 percent or more, the customer must indicate in its report how it plans to adjust its expenditures to ensure that it will retain the full C&R Discount after the Discount Period.

b. **Final Reconciliation Reports**

At the end of the Discount Period the participating customer shall prepare a Final Reconciliation Report. This report shall be submitted and received by BPA one month after the end of the Discount Period (November 1, 2006, for participating customers' purchasing power from BPA for the full five-year rate period).

This report shall identify:

i. The cumulative C&R Discount that the customer has received from BPA during the Discount Period;

ii. The cumulative Dividend Distribution Clause (DDC) amount dedicated to Qualifying Expenditures that the customer has received from BPA during the Discount Period; and

iii. The total Qualifying Expenditures that the customer has made during the Discount Period segregated into the following four categories.

I. Incremental Conservation
II. Renewable Resources
III. Low Income Weatherization
IV. Support Activities (*i.e.,* administrative, advertising, R&D.)

c. **Certification of Incremental Spending**

Each Interim Report and the Final Reconciliation Report shall include language certifying the participating customer's actual incremental spending, such as:

"[Customer] certifies that the expenditures documented in this report are incremental increases in this organization's budget for the current operating year beyond what we planned to spend absent the C&R Discount."

d. Exemption Language

If states, municipalities, or other governmental bodies in the BPA service territory require, by law or regulation, that a customer, participating in the C&R Discount, acquire or invest in new conservation and/or a new renewable resource project, then such acquisitions and investments will be deemed as incremental budget increases for the purposes of section 4 c., above.

If any utility, participating in the C&R Discount, reports Qualifying Expenditures amounting to 3 percent or more of its retail revenues, then such expenditures will be deemed as incremental budget increases for the purposes of section 4 c., above.

5. Reimbursement

a. Customers Whose Expenditures Exceed the Threshold

No reimbursements are required of any participating customer whose total Qualifying Expenditures over the Discount Period equal or exceed the total cumulative C&R Discount received from BPA.

b. Customers Whose Expenditures Fall Below the Threshold

If a participating customer's Final Reconciliation Report shows that the cumulative C&R Discount received from BPA exceed the customer's total Qualifying Expenditures, the customer may take an additional month (for a total of two months after the end of the Discount Period) to make the necessary Qualifying Expenditures and prepare a Revised Final Reconciliation Report. The final report is due to BPA within two months of the end of the Discount Period (which is December 1, 2006, for the five-year customers). If the customer's Qualifying Expenditures still do not equal or exceed its cumulative C&R Discount receipts, the customer must reimburse the difference to BPA. Such reimbursement shall be made within the same two-month grace period and shall be made using the same payment method as the customer uses for paying its wholesale bill.

BPA will not assess interest on any reimbursement paid within the two-month window. However, any payment received after the due date (December 1, 2006, for the five-year customers) shall be subject to a late payment charge as described in their Subscription contract.

6. Revenue Dividends

If BPA declares a Dividend Distribution during this rate period, the first $15 million will be allocated to conservation and renewable resource development. BPA will distribute the C&R portion of any declared dividend in the same manner outlined in this section with the following modifications:

1. In order to receive their portion of the C&R dividend, customers must be actively participating in the basic C&R Discount effort; and

2. Participating customers must spend and report two dollars of additional investment in eligible activities to receive credit toward one dollar of their Dividend Distribution share (*i.e.*, any C&R dividend will be leveraged on a two for one basis).

3. The Unit Discount for participating customers receiving the Dividend Distribution will be reset to reflect the actual amount of the DDC and their Subscription Power Purchases during the months the Dividend Distribution is in effect.

B. Conservation Surcharge

The Conservation Surcharge, where implemented shall be applied in accordance with relevant provisions of the Northwest Power Act, BPA’s current Conservation Surcharge policy, and the customer’s power sales contract with BPA. The Conservation Surcharge would apply to PF-02 (including Slice purchasers), RL-02, and NR-02 rate schedules.

C. Cost-Based Indexed IP Rate

The Cost-Based Indexed IP Rate shall be offered to any DSI Purchaser to serve its aluminum smelter operations, and at BPA’s sole discretion to any other DSI Purchaser, where the DSI Purchaser makes a contractual commitment to purchase power for all five years of the rate period from BPA under the Cost-Based Indexed IP Rate.

For DSI aluminum companies, the Cost-Based Indexed IP Rate will provide the monthly price for power by applying a monthly average index price for aluminum, to an established Rate Curve (sliding function) explained below.

The Rate Curve sets the key parameters for determining the monthly power price. This Rate Curve will have: (1) an aluminum midpoint value established at the time the power contract is finalized; (2) an upper pivot point 6 cents/lb., above the aluminum midpoint value which sets an aluminum ceiling price above which the power price will not increase further as aluminum prices rise; and (3) a lower pivot point 6 cents/lb., below the aluminum midpoint value which sets an aluminum floor price below which the power price will not decrease further as aluminum prices fall.

The appropriate IPTAC as specified in Sections II.B.2. and II.B.3. of the IP-02 will establish a power price midpoint of $23.50/MWh or $25.00/MWh for each DSI Purchaser. Depending on the applicable IPTAC rate, a lower rate limit will be set at $19.00/MWh or $20.50/MWh, and an upper rate limit will be set at $28.50/MWh or $30.00/MWh.

A Cost-Based Indexed IP Rate will also be available, at BPA's sole discretion, to non-aluminum DSIs. Any Indexed Rate offered to non-aluminum DSI customers will be designed to recover the equivalent of $23.50/MWh over the rate period, and must be based on a commodity that is a direct product of the purchaser. This commodity must be tied to a commercially recognized price index that is: (1) relied upon by multiple producers; (2) used commercially to set settlement terms between producers and consumers; (3) used for establishing longer term prices and for hedging.

1. **Calculation of the Average Annual IPTAC (A) and (B)**

The average annual IPTAC rates are calculated from annual billing determinants specified in the IP-02 Rate Schedule. The annual average of all billing determinant, including the monthly IP demand charges, the monthly LLH and HLH IP energy rates, plus the appropriate charge specified in either Sections II.B.2. or II.B.3. of the IP-02 Rate Schedule, are used to calculate the power rate midpoints.

The power price at the midpoint value of IPTAC (A) is 23.5 mills/kWh.
The power price at the midpoint value of IPTAC (B) is 25.0 mills/kWh.

2. **Establishing the Rate Curve**

The rate curve has three main features: (1) a power price midpoint value of $23.50/MWh or $25.0/MWh; (2) a lower pivot point of $19.00/MWh or $20.50/MWh, the point on the rate curve where the price of energy remains unchanged as the price of aluminum continues to fall; and (3) an upper pivot price of $28.50/MWh or $30.00/MWh, the point on the rate curve where the price of energy remains unchanged as the price of aluminum continues to rise. The following criteria will be used in establishing this rate curve.

a. The aluminum midpoint value of the rate curve shall be established at the average of aluminum forward price swap quotes received by BPA on the day of pricing, plus an appropriate risk premium of up to 2 cents. The aluminum midpoint value will not be set above 74 cents/lb. for aluminum, or below 66 cents/lb. for aluminum.

b. The lower pivot point shall be established on the rate curve at the point the price of aluminum is 6 cents lb., less than the aluminum midpoint value; the lower pivot point will intersect with the lower rate limit. The rate of change from the aluminum midpoint value to the lower pivot point is -$0.75/MWh for each cent/lb., aluminum.

c. The upper pivot point shall be established on the rate curve at the point the price of aluminum is 6 cents/lb., greater than the aluminum midpoint value; the upper pivot point will intersect with the upper rate limit. The rate of change from the aluminum midpoint value to the upper pivot point is $0.833/MWh for each cent/lb., aluminum.

Power prices assessed under this rate curve shall be rounded to the nearest 1/10th or $0.1/MWh.

3. **Monthly Rate Determination**

The power rate of a DSI Purchaser who has selected the Cost-Based Indexed IP Rate option shall be determined each month for billing purposes. For DSI aluminum companies the monthly power rate is determined by applying the average aluminum price to the rate curve. The following criteria shall be used to calculate the average aluminum price for the billing month.

a. The arithmetic mean of the previous month's London Metal Exchange Aluminum H.G. three month (LME – 3-month) futures contract (US $) shall establish the average aluminum price for the billing month.

b. Such average aluminum price shall be applied to the purchaser's rate curve to determine the power rate for the billing month.

c. Monthly power rates under the Cost-Based Indexed IP Rate shall be a single flat energy rate for each month. There will not be a separate charge for demand and energy.

D. 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 Dow Jones 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 heavy load hour (HLH) and a light load hour (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: (1) the average of the closing price for the last 15 days of trading if using a futures market such as NYMEX; or (2) the monthly volume weighted average of all posted daily prices if using a cash market such as Dow Jones. The MIMA will be calculated as follows:

Index	=	BPA's current forecast or forward transaction price of the market index referenced
PF	=	Monthly PF demand and HLH and LLH energy rates.
Cost of Insurance	=	The premium on a physical or financial instrument used to mitigate the risk.
MIMA	=	Index price minus PF (forward price or forecast) + Cost of Insurance.

Note: when index price (at contract origination) is above PF, the resulting adjustment before insurance will be the application of a discount. When the index price (at contract origination) is below PF, the resulting adjustment before insurance will be the application of a premium. All adjustments are fixed for the duration of the rate period.

E. Cost Contributions

BPA has made the following resource cost determinations:

1. The forecasted average cost of resources available to BPA under average water conditions is 19.38 mills/kWh.

2. The approximate cost contribution of different resource categories to each rate schedule is as shown in Table A:

Table A

Rate Schedule	***Resource Cost Contribution***		
	Federal Base System	**Exchange**	**New Resources**
PF	100%	0%	0%
IP	51.31%	44.99%	3.70%
NR	51.31%	44.99%	3.70%

F. Cost Recovery Adjustment Clause (CRAC)

The CRAC is a temporary, upward adjustment to posted power rates for Subscription sales if Actual Accumulated Net Revenues (AANR) in the generation function fall below a threshold level.

The CRAC applies to power customers under these firm power rate schedules: PF Preference [(PF excluding Slice), Exchange Program, and Exchange Subscription], Industrial Firm Power (IP-02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate, Residential Load (RL-02), including the financial portion of any Residential Exchange Settlement under this rate schedule, New Resource Firm Power (NR-02), and Subscription purchase under Firm Power Products and Services (FPS). The CRAC does not apply to Pre-Subscription rates or Slice purchases.

1. Formula for the Calculation of the Revenue Amount and CRAC Percentage

If the AANR at the end of any Fiscal Year 2001 through 2004 falls below the CRAC Threshold applicable to that fiscal year, the CRAC triggers, a rate increase for a 12-month period beginning the following April.

The Revenue Amount will be determined by the following formula:

Revenue Amount is the lower of:
CRAC Threshold – AANR; or
The annual Maximum Planned Recovery Amount, shown in Table B below.

Where Revenue Amount is the amount of additional revenue that an increase in rates under CRAC is intended to generate during the period that the rate increase is effective;

Where CRAC Threshold is the "trigger point" for invoking a rate increase under the CRAC. The threshold is pre-specified for the end of Fiscal Years 2001, 2002, 2003, 2004, and 2005 in Table B.

Where AANR is actual generation function net revenues, as accumulated since 1999, at the end of each of the Fiscal Years 2001 through 2005. Net revenues for any given fiscal year are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Practices. Only generation function revenues and expenses, which is to say accrued revenues and accrued expenses that are associated with the production, acquisition, marketing, and conservation of electric power, will be included in determinations under the CRAC. Accrued revenues and expenses of the transmission function are excluded. The determination of AANR will be confirmed by BPA's independent auditing firm.

Where Maximum Planned Recovery Amount is the maximum annual amount planned to be recovered through the CRAC. Rate increases under the CRAC take effect on April 1 following the end of a fiscal year in which the AANR falls below the CRAC Threshold.

If the AANR in Fiscal Year 2005 falls below the CRAC Threshold, the CRAC triggers, and rates will be increased for a six-month period effective the following April 1. The Revenue Amount will be determined by the following formula:

Revenue Amount is the lower of:
(CRAC Threshold – AANR) divided by 2; or
$87.5 million ($175 million divided by 2)

Table B

Fiscal Year	**CRAC Threshold (AANR, $ Millions)**	**Maximum Planned Recovery Amount (Beginning Following April)**
2001	-350	125
2002	-350	135
2003	-250	150
2004	-250	150
2005	-250	87.5

Once the Revenue Amount is determined, that amount will be converted to the CRAC Percentage. The CRAC Percentage is the percentage increase in each of the firm power rate schedules listed above. This percentage will be applied for a period of time to generate the additional (CRAC) revenue. The CRAC Percentage will be determined by the following formula:

CRAC Percentage =
Revenue Amount
Divided by
CRAC Revenue Basis,

Where CRAC Revenue Basis is the total generation revenue for the loads subject to CRAC, plus any Slice loads, for the fiscal year in which the CRAC implementation begins, based on the then most current revenue forecast.

Each non-Slice product's total charge for energy, demand and load variance will be increased by this CRAC Percentage amount.

2. CRAC Adjustment Timing

In January of each year of the rate period, the Administrator will determine whether the AANR at the end of the preceding fiscal year fell below the CRAC Threshold. If the AANR is below the CRAC Threshold, the Administrator will propose, in January, to increase applicable rates effective in the following April. The adjustment is applied to power deliveries beginning April 1. Any such increase beginning in Fiscal Years 2002-2005 remains in effect through March of the following year. An increase beginning in the final fiscal year of the rate period (2006) will remain in effect through September 2006.

3. CRAC Notification Process

BPA shall follow the following notification procedures:

a. Financial Performance Status Reports

i. Each quarter, BPA shall post on its electronic information access (World Wide Web) site preliminary, unaudited year-to-date aggregate financial results for generation, including accumulated net revenues.

ii. By no later than August 31 of each year, BPA shall post on its website a forecast of AANR attributable to the generation function for the fiscal year ending September 30. By no later than December 1 of each year, BPA shall also post on its website the unaudited AANR.

b. Actions to Mitigate Need for a CRAC

If actual accumulated net revenues at the end of a fiscal year are within $150 million of the CRAC Threshold for the subsequent year, BPA will prepare and post on its Web site an analysis of the causes of BPA's financial decline compared to the rate case plan, and propose a prioritized list of potential actions to avert or mitigate the need for a CRAC. BPA shall conduct a public comment period on these actions to avert or reduce a potential CRAC rate adjustment by the following March.

c. Notice of CRAC Trigger

BPA shall notify all customers and rate case parties on or about January 15 in each of the Fiscal Years 2002-2006, if the AANR fell below the CRAC Threshold for that fiscal year and the extent to which BPA intends to adjust rates under the CRAC. (If the December unaudited AANR report for the generation function indicated that the CRAC Threshold might be reached, and the audited actuals show that it has not triggered, customers and rate case parties will be so notified.) Notification will include the audited AANR for the prior fiscal year, the calculation of the Revenue Amount, and the estimated CRAC Percentage. The notice shall also describe the data and assumptions relied upon by BPA. Such data, assumptions and documentation, if non-proprietary and/or non-privileged, shall be made available for review at BPA upon request. The notice shall also contain the tentative schedule for the remainder of the CRAC implementation process.

On or about February 1 of any of the Fiscal Years 2002-2006 in which the AANR falls below the CRAC Threshold, BPA staff shall conduct a public forum to explain the AANR result, the calculation of the Revenue Amount and the CRAC Percentage, and demonstrate that the CRAC has been implemented in accordance with the GRSPs. The forum will provide an opportunity for public comment.

On or about March 1 of any of the Fiscal Years 2002-2006 in which the AANR falls below the CRAC Threshold, the BPA Administrator shall notify all customers to whom the CRAC applies of the final calculation of the adjustment and the resulting rate increase (as a percentage) applicable to each rate schedule.

G. Demand Adjuster

The Demand Adjuster is applied to a customer's demand billing factor. It is a number less than or equal to one calculated by dividing the customer's Total Retail Load on the GSP by the customer's Total Retail Load on their system peak. The minimum Demand

Adjuster is 0.6 six tenths. The Demand Adjuster is used with the demand billing factor for the Actual Partial Service Products, and with the demand billing factor for the Block with Factoring.

H. Dividend Distribution Clause (DDC)

The DDC is a clause establishing criteria and public process requirements that the Administrator will use to decide whether dividends should be distributed and the amount that should be distributed. The DDC enables BPA to distribute dividends to customers and other stakeholders. The DDC also establishes the mechanism to be used to make a distribution to certain firm power customers.

The DDC applies to power customers under these firm power rate schedules: PF Preference [(PF excluding Slice), Exchange Program, and Exchange Subscription], Industrial Firm Power (IP-02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate, Residential Load (RL-02) including the financial portion of any Residential Exchange Settlement under this rate schedule, New Resource Firm Power (NR-02), and Subscription purchases under Firm Power Products and Services (FPS). The DDC does not apply to Pre-Subscription rates or Slice purchases.

The DDC does not apportion, or establish criteria for apportioning, dividends to customers under the above firm power rate schedules other than to qualifying power customers participating in the Conservation and Renewables Discount (C&R Discount), or to other customers and stakeholders.

"Stakeholders" are groups or public purposes that have a fundamental policy or financial interest in BPA's generation function. These groups include, but are not limited to, customers subject to the posted firm power rate schedules cited above.

1. Formula for the Calculation of the Dividend Distribution Amount

The DDC process will be implemented if audited actual accumulated net revenues for the end of any of the fiscal years 2001-2005 are above the DDC Threshold value.

Actual Accumulated Net Revenues (AANR) are generation function net revenues, as accumulated since 1999, at the end of each of the Fiscal Years 2001 through 2005. Net revenues are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Practices. Only generation function revenues and expenses, which is to say accrued revenues and accrued expenses that are associated with the production, acquisition, marketing, and conservation of electric power, are included in determinations under the DDC; accrued revenues and expenses of the transmission function are excluded. The determination of AANR will be confirmed by BPA's independent outside auditing firm.

DDC Threshold is the minimum level of AANR that must be realized before a dividend distribution is considered. The DDC Threshold is $250 million for the end of Fiscal Years 2001, 2002, 2003, 2004, and 2005.

DDC Amount is the aggregate amount that is available to be distributed to customers and stakeholders. The DDC Amount may be equal to zero and will be determined by the following formula:

> DDC Amount is the lower of:
> AANR – DDC Threshold; or
> Cash in excess of that needed to meet the Treasury Payment Probability (TPP) Standard, based on the Five-Year Forecast

Where the TPP Standard is an 88 percent probability that all planned payments to the U.S. Treasury will be paid on time and in full over the Five-Year Forecast period (or equivalent financial criterion in the event that BPA replaces its TPP Standard); and

Where the Five-Year Forecast is the forecast of accrued revenues and expenses, and the risk analysis and assessment of TPP or any replacement financial criterion, for the current year and subsequent four years that the Administrator prepares and subjects to public review and comment if the DDC Threshold has been met.

The portion of the DDC Amount allocated to power customers (the Power Customers' DDC Amount) will be determined according to a plan to be adopted in a public process BPA will conduct (*see* Section 3 below). The Power Customer DDC Amount will be converted to a percentage (the Power Customer DDC Percentage), which will be applied to all power customer rates subject to the DDC to arrive at the amount to be rebated on power bills for each of the included power customers.

The Power Customer DDC Percentage will be determined by the following formula:

> Power Customer DDC Percentage equals:
> Power Customer DDC Amount
> Divided by the
> DDC Revenue Basis

Where DDC Revenue Basis is the total generation revenue for the loads subject to the DDC for the fiscal year in which the DDC implementation begins, based on the then most current revenue forecast.

Each covered power customer will receive a rebate equal to the Power Customer DDC Percentage applied to their total charge for energy, demand and load variance. For any customer or stakeholder entitled to a dividend who is not a power customer, the Administrator will convert the DDC Percentage to a dollar figure.

2. Determination and Timing of a Dividend Distribution

In January of each year of the rate period (FY 2002-2006), the Administrator will determine whether the AANR exceeds the DDC Threshold. If the AANR exceeds the DDC Threshold: (1) customers and rate case parties will be so notified; and (2) the Administrator will prepare a Five-Year Forecast. On or about March 1, the Administrator will propose to distribute or not distribute dividends. The Administrator will issue a final decision on the proposal on or about April 15.

Dividends distributed to customers are included in energy deliveries beginning May 1, and, for any Fiscal Years 2002-2005, remain in effect for 12 months *i.e.,* through April 30 of the following year. In the last year of the rate period (FY 2006), the rebate would expire on September 30, 2006.

3. Determining How the Distribution is Allocated

The first $15 million of the DDC Amount, if the DDC Amount exceeds $15 million, or the entire DDC Amount if it equals $15 million or less, will be allocated to qualifying customers' participating in the C&R Discount.
The C&R Discount is a rate mechanism designed to encourage incremental conservation and renewable resource development by BPA's power purchasers under PF, IP, RL, and NR rate schedules. *See* C&R Discount GRSPs, Section II.A.

BPA intends to conduct a separate public consultation process by October 1, 2001, to develop the criteria for allocating any remaining DDC Amount (exceeding the $15 million for the C&R Discount) among customers and stakeholders.)

4. Dividend Distribution Notification Process

BPA shall follow the following notification procedures:

a. **Financial Performance Status Reports**

By no later than August 31 of each year, BPA shall post on its electronic information access site (World Wide Web) a forecast of AANR attributable to the generation function for the fiscal year ending

September 30. By December 1 of each year, BPA shall post on its website the unaudited AANR.

b. **Notice of DDC Trigger**

On or about January 15 in each of the Fiscal Years 2002-2006, BPA will notify all power customers and rate case parties if the AANR exceeds the DDC Threshold. (If the December unaudited AANR report for the generation function indicated that the DDC Threshold might be exceeded, and the audited actuals show that it was not exceeded, customers will also be notified). Notification will include the AANR for the prior fiscal year, the DDC Amount, the calculation of the DDC Amount, and the estimated resulting Power Customer DDC Percentage for each applicable rate schedule. The notice shall also describe the data and assumptions relied upon by BPA. Such data, assumptions, and documentation, if non-proprietary and/or non-privileged, shall be made available for review at BPA upon request. The notice shall also contain the tentative schedule for the remainder of the DDC implementation process.

(1) On or about March 1 of any of the Fiscal Years 2002-2006 in which the AANR exceeds the DDC Threshold, the Administrator will post the Five-Year Forecast on BPA's website and will propose to distribute or not distribute dividends. During March, BPA will conduct a public review and comment process on the proposal.

(2) On or about April 15 of any of the Fiscal Years 2002-2006 in which the AANR exceeds the DDC Threshold, BPA shall notify customers to which the DDC applies of the decision on the proposal, the final calculation of the DDC Amount, the allocation of the DDC Amount, and, if applicable, the resulting level of the Power Customer DDC Percentage to be applied to each applicable firm power rate schedule.

I. Excess Factoring Charges

1. Excess Within-Day Factoring Charge

The within-day factoring test compares the hour-by-hour shape of the customer's load to 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.

Excess Within-Day Factoring Charge, for any hour(s) in the month, applies to amount of hourly energy in excess of the authorized maximum energy amounts defined by the customer's within-day load shape.

The total amount of Excess Within-Day Factoring Charge during the HLH's of the month shall be billed the greater of:

a. Five (5) mills/kWh;

b. Among all HLH periods of the billing month, the maximum within-day difference between the highest hourly HLH California Independent System Operator (ISO) Supplemental Energy price (NP15) and the lowest hourly HLH California ISO Supplemental Energy price (NP15).

The total amount of Excess Within-Day Factoring Charge during the LLH's of the month shall be billed the greater of:

a. Five (5) mills/kWh;

b. Among all LLH periods of the billing month, the maximum within-day difference between the highest hourly LLH California ISO Supplemental Energy price (NP15) and the lowest hourly LLH California ISO Supplemental Energy price (NP15).

In the event that the index for ISO Supplemental Energy expires, that index will be replaced for the purpose of deriving Excess Within-Day Factoring Charges by another hourly energy index, such as the California Power Exchange (CalPX) (NW1 or NW 3), at a hub at which Northwest parties can trade.

2. Excess Within-Month Factoring Charges

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-to-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, the customer resource deliveries were zero for a particular day. The within-month factoring test is equipped to address that type of instance. 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.

Excess Within-Month Factoring Charge applies to that amount of energy take that either exceeds or falls short of a range defined by: (1) a flat load placement on BPA; and (2) a load placement that follows the customer's actual load shape.

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

The Excess Within-Month Factoring during the HLH's of the month shall be billed the greater of:

a. Five (5) mills/kWh.

b. The highest peak Dow Jones (DJ) Mid-Columbia (Mid-C) Index price for firm power during the month LESS the lowest peak DJ Mid-C Firm Index price for firm power during the month.

c. The highest average HLH California ISO Supplemental Energy price (NP15) (average of hours 7 through 22, excluding Sundays) during the month LESS the lowest average HLH California ISO Supplemental Energy price (NP15) for the same period.

The Excess Within-Month Factoring during the LLH's of the month shall be billed the greater of:

a. Five (5) mills/kWh.

b. The highest offpeak DJ Mid-C Index price for firm power during the month LESS the lowest offpeak DJ Mid-C Index price for firm power;

c. The highest average LLH California ISO Supplemental Energy price (NP15) (average of hours 1 through 6, and 23, and 24 Monday through Saturday; average of hours 1 through 24 Sunday) during the month LESS the lowest average LLH California ISO Supplemental Energy price (NP15) for the same month in the same time period.

The DJ Mid-C Index definitions for HLH's (or Peak) and LLH's (or offpeak) will be adjusted, as necessary, to be consistent with (comport with) BPA's definition for HLH and LLH periods.

In the event that the index for ISO Supplemental Energy or DJ Mid-C Index expires, that index will be replaced for the purpose of deriving Excess Within-Month Factoring Charges by another hourly or diurnal energy index, such as the CalPX (NW1 or NW3), at a hub at which Northwest parties can trade.

J. Five-Year Flat Block Price Forecast

The Five-Year Flat Block Price Forecast is BPA's price estimate of the market price for five-year block purchases for the 2002-2006 period. This forecast is used in calculating the cash component of the proposed settlement of the Residential Exchange Program with regional IOUs as described in BPA's Power Subscription Strategy. The Five-Year Flat Block Price Forecast is $28.1 per megawatthour (MWh).

K. Flexible IP Rate Option

The Flexible IP rate option will be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option for all five years of the rate period. The charges and billing factors under this option will be 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 NPV Revenues: Forecasted revenues from a Purchaser under the Flexible IP 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 IP rate schedule Section II been applied to the same sales.

The Flexible IP rate contract may establish a limit on the amount of power purchased at the Flexible IP rate. In this case, purchases beyond the contractual limit will be billed at the Demand and Energy charges specified in the IP rate schedule Section II unless such power would be charged as an Unauthorized Increase.

Risk Adjustments: Credit risk associated with individual customers will be a factor in establishing any flexible 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," expense charge, built into the rates, or other methods acceptable to BPA.

L. Flexible NR Rate Option

The Flexible NR rate option will be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. 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 Purchaser under this option. The customers purchasing under the Flexible NR rate option purchase the same set of power products and services that they would otherwise purchase under the rate schedule. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying the following condition:

Equivalent NPV Revenues: Forecasted revenues from a Purchaser under the Flexible 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 NR rate schedule Section II been applied to the same sales.

The Flexible NR rate contract may establish a limit on the amount of power purchased at the Flexible NR rate. In this case, purchases beyond the contractual limit will be billed at the Demand and Energy (and Load Variance and Stepped-Up Multiyear Block (SUMY), if appropriate) charges specified in the PF rate schedule Section II, unless such power would be charged as an Unauthorized Increase.

M. Flexible PF Rate Option

The Flexible PF rate option will be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. 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 Purchaser under this option. The customers purchasing under the Flexible PF rate option purchase the same set of power products and services that they would otherwise purchase under the rate schedule. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying the following condition:

Equivalent NPV Revenues: Forecasted revenues from a Purchaser under the Flexible PF 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 PF rate schedule Section II been applied to the same sales.

The Flexible PF rate contract may establish a limit on the amount of power purchased at the Flexible PF rate. In this case, purchases beyond the contractual limit will be billed at the Demand and Energy, (and Load Variance and SUMY, if appropriate) charges specified in the PF rate schedule Section II, unless such power would be charged as an Unauthorized Increase.

N. Green Energy Premium

1. Overview of the Premium

The Green Energy Premium (GEP) is a premium ranging from zero to $40/MWh that a customer elects to pay BPA to ensure that BPA is producing some system power from Environmentally Preferred Power (EPP) resources. The GEP is the difference between the customer's applicable average annual energy charge under the PF-02, RL-02, NR-02, and IP-02 rates and the total cost of the EPP resource selected by the customer. The GEP is applied to the number of EPP MWh that the customer has elected to purchase. BPA guarantees the customer paying the premium that BPA will produce an amount of EPP equal to the amount of energy subject to this adjustment. The GEP will be charged in a line item on the monthly power bill of each participating customer.

The costs to be considered in determining the applicable GEP include, but are not limited to:

- Costs of existing EPP resources, over and above the cost of BPA system resources.
- Costs of new EPP resources, over and above the cost of BPA system resources.
- Costs of BPA system resources.
- Endorsement fees for specific EPP resources.
- Market purchases of EPP resources.
- Transmission and other services required to integrate EPP resources into the BPA system.

2. Calculation and Application of the Premium

a. Determination of the Premium

For a customer buying power from BPA under a requirements firm power sales contract, the amount of EPP and the GEP will be determined as part of the product selection process and will be completed as part of the power sales contract negotiation. The charge will not exceed $40 per MWh and may be as low as zero. The premium will be zero if the unit cost of the GEP resource(s) dedicated to the customer is equal to, or less than, the energy charge of the applicable rate. The GEP will recover the average unit cost of the EPP resource(s) minus the applicable average PF-02, RL-02, NR-02, and IP-02 energy charge over the term of the purchase.

b. Determination of Individual Customer GEP

(1) Customers will be provided notice of the availability of specific GEP products and associated premiums. The total GEP for the customer will be based on the customer's elections of product amounts and content.

(2) The average annual energy charge will be calculated as the average per kWh charge for an annual flat undelivered product using the energy charges applicable to the customer. Where customers are purchasing under more than one rate schedule, the average energy charge will be calculated using expected loads and applicable rate schedules.

(3) The individual customer GEP for billing will be the total cost of the product selected by the customer minus the average annual energy charge.

c. **Application of the GEP**

The GEP will be applied after BPA has determined all other charges and credits except the C&R Discount line item, on the participating customer's power bill.

d. **Billing for the Premium**

The customer's bill will include a line item showing the kWh amount of EPP purchased times the GEP for the products elected and the total cost. The calculation will appear as:

(EPP amount) kWh * GEP mills/kWh = $XXXXX

O. Guaranteed Delivery Charge (NF only)

A surcharge of 2.00 mills/kWh of Billing Energy is applied whenever BPA guarantees delivery of nonfirm energy to a Purchaser under the Nonfirm Energy (NF) Standard rate or Market Expansion rate.

P. Industrial Firm Power Targeted Adjustment Charge (IPTAC)

1. Availability

The IPTAC pertains to the IP rate schedule. The IPTAC will be applied to Firm Power requirements service of DSIs who take service from a combination of Federal inventory and power purchased from the market during the 2002 rate period.

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

There will be two rates for the IPTAC product. 1,210 aMW will be sold at $23.50 per MWh, and 230 aMW sold at $25 per MWh.

Q. Low Density Discount (LDD)

1. Application and Definitions

For eligible Purchasers as defined in section 2 below, a discount shall be applied each billing month to BPA's charges for the following components of the PF Preference rate, the PF Exchange Program rate, and the NR-02 rate: (1) Demand; (2) HLH purchases; (3) LLH purchases; and (4) Load Variance. The Low Density Discount (LDD) shall not be applied to Unauthorized Increase Charges, Excess Factoring Charges, transmission charges or any other charges. The discount shall be revised annually based on data supplied by June 30 of each Calendar Year (CY) for the previous CY and shall become effective on the upcoming October 1.

a. **The Kilowatthour/Investment Ratio**

The kWh/Investment (K/I) ratio is calculated annually based on the data supplied by June 30 for the previous CY. The K/I ratio is calculated by dividing the Purchaser's Total Retail Load during the CY by the value of the Purchaser's depreciated electric plant (excluding generation plant) at the end of the CY.

b. **The Consumers/Mile of Line Ratio**

The Consumers/Mile of Line (C/M) ratio is determined annually using the data supplied by June 30 for the previous CY. The C/M ratio is calculated by dividing the maximum number of consumers within the distribution system, in any one month during the CY, by the end of CY number of pole miles of distribution.

Consumer means every billed consumer regardless of usage. Separately billed services for water heating and security lights are not counted as an additional billed consumer.

The number of pole miles of distribution line means the end of CY pole miles. Distribution lines are defined as lines that deliver electric energy from a substation or metering point, at a voltage of 34.5 kilovolt (kV) or less, to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities. (Service drops are considered service facilities.)

These calculations shall be based on CY data provided from the Purchaser's annual financial and operating reports. The Purchaser shall certify that the data submitted is correct and that no loads gained as provided in section 6, Retail Access Exclusion, are receiving LDD benefits.

In calculating these ratios, BPA shall compile the data submitted by the Purchaser based on the Purchaser's entire electric utility system in the PNW. For Purchaser's 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 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, in its sole discretion, may waive the requirement to submit separate data for the Purchaser with a small amount of its system outside the PNW. Results of the calculations shall not be rounded.

A Purchaser who has not provided BPA with the requisite pieces of data needed to calculate the K/I and C/M ratios by June 30 of each year, for the prior CY, shall be declared ineligible for the LDD, effective the upcoming October 1.

If a Purchaser's data was submitted on time and a revision is necessary to the data, the revised data must be resubmitted no later than 12 months after the original submission date to be considered for an adjustment.

2. Eligibility Criteria

To qualify for a discount, the Purchaser must meet all five of the following eligibility criteria:

a. the Purchaser must serve as an electric utility offering power for resale;

b. the Purchaser must agree to pass the benefits of the discount through to the Purchaser's eligible consumers within the region served by BPA;

c. the Purchaser's average retail rate for the reporting year must exceed the Purchaser's average cost of BPA power purchases under the applicable rate for the qualifying period by at least 10 percent. For CY 2001, the Purchaser's average cost of BPA power purchases under the applicable rate shall be under the applicable 1996 rate for the first nine months and under the applicable 2002 rate for the last three months. For CY 2002 and beyond, the Purchaser's average cost of BPA power purchases under the applicable rate shall be under the applicable rate for all 12 months;

d. the Purchaser's K/I ratio must be less than 100; and

e. the Purchaser's C/M ratio must be less than 12.

3. Discounts

The Purchaser shall be awarded the following discount beginning October 1, 2001, in accordance with section 4 below. The discount will be the sum of the two potential discounts for which the Purchaser qualifies, based on the following Table C. The discount shall not exceed 7 percent.

Table C
LDD Percentage Discount Table

Percentage Discount	***Applicable Range for kWh/Investment (K/I) Ratio***	***Applicable Range for Consumers/Mile (C/M) Ratio***
0.0%	$35.0 \leq X$	$12.0 \leq X$
0.5%	$31.5 \leq X < 35.0$	$10.8 \leq X < 12.0$
1.0%	$28.0 \leq X < 31.5$	$9.6 \leq X < 10.8$
1.5%	$24.5 \leq X < 28.0$	$8.4 \leq X < 9.6$
2.0%	$21.0 \leq X < 24.5$	$7.2 \leq X < 8.4$
2.5%	$17.5 \leq X < 21.0$	$6.0 \leq X < 7.2$
3.0%	$14.0 \leq X < 17.5$	$4.8 \leq X < 6.0$
3.5%	$10.5 \leq X < 14.0$	$3.6 \leq X < 4.8$
4.0%	$7.0 \leq X < 10.5$	$2.4 \leq X < 3.6$
4.5%	$3.5 \leq X < 7.0$	$1.2 \leq X < 2.4$
5.0%	$X \leq 3.5$	$X < 1.2$

4. LDD Phase-Out Adjustment

If the Purchaser satisfies the eligibility criteria (2. a. through e.), and the calculated discount differs from the existing discount by more than one-half of 1 percent, the applicable discount will be:

a. the existing discount plus one-half percent if the calculated discount exceeds the existing discount; or

b. the existing discount minus one-half percent if the calculated discount is less than the existing discount.

The foregoing formula will be applied each October 1 until the then-current calculated discount is fully phased out.

The Purchaser is not eligible to receive any discount, effective each October, if the Purchaser fails to meet the eligibility criteria in section 2. a. through e.

5. Additional Adjustment for Very Low Densities

If a Purchaser's C/M ratio is 3 or less and its K/I ratio is 26 or less, after determination of the discount pursuant to sections 3 and 4 above, an additional one-half percent shall be added to the Purchaser's discount, but the total discount shall not exceed 7 percent. In subsequent years, the one-half percent added to the discount pursuant to this section shall not be included when determining the applicable discount in section 4 above.

6. Retail Access Exclusion

Load that is gained by a Purchaser as a direct result of retail access rights established by Federal, state, or local legislation, and that would not otherwise have been gained absent such legislation, is not eligible to receive the benefits provided by the LDD. The Purchaser shall not pass the benefits of the LDD to its gained load consumers.

7. Application of the LDD to Slice

To be eligible for the LDD, customers that purchase the Slice product must meet the eligibility criteria under section 2.

The LDD benefit for Slice customers will be determined and applied as follows:

By September of each year, BPA will establish a dollars/MWh discount rate for each one-half percent discount bracket, from 0.5 percent to 7 percent. The dollars/MWh discount rate for each bracket will be determined by using billing data of customers within the same non-Slice LDD percentage bracket. Those customers' total dollars in non-Slice LDD discounts they received will be divided by the total eligible MWh purchased. This will result in a dollars/MWh rate that can then be used as the yearly/monthly discount for a Slice customer that is eligible, under section 3, to receive the same discount. BPA will use billing data from the previous CY from the non-Slice LDD recipients when calculating the dollars/MWh discount rate for Slice product recipients. When there are no non-Slice LDD recipients available in a given discount bracket to calculate the $/MWh value, it is appropriate to determine a linear relationship using a regression analysis to arrive at a $/MWh value for that bracket. When there is an increase or decrease in the PF rate for HLH and LLH billing determinants, not due to the Targeted Adjustment Charge (TAC), CRAC, or the DDC, the regional average increase or decrease will be applied to the $/MWh rate that coincides with the increase or decrease rate(s) for the non-Slice LDD recipients for the same period.

The rate will only be applied to that portion of Slice power being purchased that is requirements power. This quantity is defined in the Slice Contract as Critical Slice Amount. The annual Slice true up will include an LDD true-up if based on estimates. If it is based on after-the-fact monthly data, no true-up is necessary.

R. Rate Melding

BPA's rate proposal allows the customers more than one rate choice. Separately tracking and administering the customers 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.,* CRAC), or a significant change in the loads applicable to the rates occurs.

S. Slice True-Up Adjustment

Each year, when the audited actual Slice Revenue Requirement for the previous fiscal year is available, BPA will calculate the final true-up for the previous fiscal year. BPA will calculate the final true-up for the previous fiscal year based on the difference between the Slice Revenue Requirement's audited actual expenses (and credits) and those expenses (and credits) forecasted in the 2002 Power rate case. This true-up will be the True-Up Adjustment Charge and will be applied to the customer's bills. See the Slice Product Costing and True-Up Table (Table D). Inventory Solution costs will be trued-up in a slightly different manner, using the formula in Table E.

Table D

	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**	**$ 1,362,835**	**$ 1,375,894**	**$ 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	$ 17,953	$ 18,187	$ 18,436	$ 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	$ 15,450	$ 13,250	$ 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	$ 396	$ 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**

Table D (Continued)

			A	B	C	D	E		F
	PBL Costs ($000)	2002-2006	2002	2003	2004	2005	2006		TOTAL
		Audited	Projected						
74		Actuals							
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	$ 26,685	$ 26,685		$ 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 Trnfrs & 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 aMW's on average)		$ 322,218	$ 336,766	$ 289,159	$ 323,744	$ 306,070		$ 1,577,958
116	DSI Augmentation (450 aMW's)		$ 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 aMW's flat, 450 aMW's 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									

T. Stepped-Up Multiyear Block (SUMY)

The SUMY Block charge applies to Block purchases if the annual amounts increase (*i.e.,* step-up) over multiple years of a purchase commitment term due to increases in customer net requirement which are not subject to a TAC.

The cost for the SUMY Block service is the difference between PF-02 rates and the AURORA On and Offpeak market price forecast in the final rate proposal.

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.

The SUMY charge is the total cost of the SUMY Block service divided by the total Block energy purchase including stepped-up amounts. The charge is in addition to the PF and NR energy and demand rates that the customer will pay for these power purchases.

Formula for Calculating a Charge for SUMY Block Service:

Step 1: Determine HLH MWh of SUMY Block.
October 2002 HLH Block minus October 2001 HLH Block = HLH MWh of SUMY Block for October 2002

Step 2: Determine LLH MWh of SUMY Block.
October 2002 LLH Block minus October 2001 LLH Block = LLH MWh of SUMY Block for October 2002

Step 3: Determine Cost of HLH SUMY Block service.
HLH MWh of SUMY Block * (Aurora October 2002 On-Peak Market Price minus October 2002 PF HLH energy and demand rate) = Total Cost of October 2002 HLH SUMY Block service.

Step 4: Determine Cost of LLH SUMY Block service.
LLH MWh of SUMY Block * (Aurora October 2002 Off-Peak Market Price minus October 2002 PF LLH energy rate) = Total Cost of October 2002 LLH SUMY Block service.

Step 5: Determine Cost for all months of the rate period by repeating Steps 1-4 for each month of the remaining purchase period always calculating the MWh difference from the first year and corresponding month. Calculate the price difference using that year's and month's market price and PF rate.

Step 6: Custom Charge: Divide the Net Present Value (NPV) of the stream of costs derived from Steps 1-5 by the NPV of the total block purchase including SUMY Block in MWh for the five-year period. The NPV uses a 6.8 percent discount rate and is present valued to October 2001.

Step 7: Billing Determinant: Custom charge is applied to each MWh of block purchase including the SUMY Block amounts.

U. Supplemental Contingency Reserves Adjustment (SCRA)

The energy charges stated in the IP-02 rate schedule will be adjusted to reflect the negotiated SCRA adjustment. PBL will negotiate with any DSI interested in providing Supplemental Contingency Reserves (Supplemental Reserves). Supplemental Reserves refers to generating capacity, and associated energy, fully available within 10 minutes notice of a system disturbance. PBL has established a flexible rate with a cap that will permit BPA to negotiate a price according to the quality of reserves provided.
The maximum amount PBL may pay for Supplemental Reserves from a DSI is capped at $5.63/kW-mo.

The suitability and quality of the Supplemental Reserves will be measured by whether they have certain characteristics, some of which are required and others optional. Any Supplemental Reserves purchased by PBL must be consistent with North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and Northwest Power Pool (NWPP) criteria:

1. the interruptible load must be offline within five minutes after a call by BPA;

2. in the event of a system disturbance, the interruptible load must be accessible prior to a request for reserves from other NWPP parties; and

3. the interruptible load must be available to be offline for up to 60 minutes.

In addition to these required characteristics, the issues identified below will help define when PBL may pay the maximum value for Supplemental Reserves:

1. the extent to which PBL has the discretion when and how to use all operating reserves and to determine what resources to call on in the event of a system disturbance; and

2. whether there are limitations on the number of times or total minutes the reserves may be utilized.

V. Targeted Adjustment Charge (TAC)

1. Availability

The TAC pertains to the PF rate schedule, except for PF exchange program and PF Exchange Subscription rates. The TAC also applies to purchases under the NR rate. 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. TAC also applies to customers that add load through retail access after the window closes including load that was once served and returns under retail access.

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. The TAC will not apply to purchases included in a customer's initial Subscription contract.

If a public agency customer that requests requirements service from BPA is annexing or otherwise taking on the obligation of load from another public agency customer and the request to annex or take on load obligation and the reduction in obligation are equal amounts such that BPA's total load obligation does not increase, BPA may exempt the newly acquired load from the TAC and apply PF-02. The TAC will apply if the annexed requirements service has been previously served by that 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 benefit (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, if any, must apply until 2006.

If a customer is serving a portion of its load with a certifiable renewable resource eligible for the C&R Discount, or 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, during the 2002 to 2006 rate period, requirements firm power service for such load at the end of the specified contract period at PF Preference (PF-02) without being subject to the TAC. This limited exception applies to the first 200 aMW in any contract year, or to amounts that BPA specifies in accordance with its Policy on the Determination of Net Requirements.

2. Energy Charge

The TAC is a monthly mills/kWh adjustment to the HLH and LLH energy rates specified in the 2002 rate schedule, and is applied to that portion of the Purchaser's load that is subject to the TAC. The TAC rate adjustment will be established based on the following formula:

TAC = [(Incr $ * Incr Amt) – (Rate $ * Incr Amt)]/TAC Amt

where:

TAC Amt	=	The amount of load subject to the TAC, determined monthly.
Rate $	=	The monthly PF (or NR) energy rate shown in the applicable rate schedule.
Inventory Amt	=	Amount of energy in inventory available to serve this load based on average annual Federal system firm resource capability, estimated using critical water excluding balancing purchases and purchases for system augmentation, from the 2002 rate case with updates if BPA determines that is necessary.
Incr $	=	Monthly cost to BPA, including a handling fee, of incremental power purchases expressed in mills/kWh. These costs also may include, where applicable, wheeling, ancillary, and other charges BPA may incur in purchasing power from other entities such as, but not limited to, the California ISO or the CalPX.
Incr Amt	=	Amount of incremental power required, determined monthly and defined as the TAC Amt minus the Inventory Amt. (If there is no available Inventory Amt, the Incr Amt will equal the TAC Amt).

If Incr $ is less than Rate $, the TAC is 0 mills/kWh.

TAC is the monthly rate adjustment in mills/kWh.

BPA will calculate the cost (Incr $) per month in mills/kWh of the additional power per month (Incr Amt) for a specific customer request. BPA will establish the cost of the additional power by the following methods:

- BPA will establish the price based on BPA's monthly cost to purchase the incremental load by purchases of resources at market.

W. Unauthorized Increase Charge

1. Charge for Unauthorized Increase in Demand

The amount of Measured Demand during a billing hour that exceeds the amount of demand the purchaser is contractually entitled to take during that hour shall be billed at the greater of:

a. Three (3) times the applicable monthly demand charge;

b. The sum of hourly California ISO Spinning Reserve Capacity prices for all HLHs in the month, at path NW1 (COB); or

c. The sum of hourly California ISO Spinning Reserve Capacity prices for all HLHs in the month, at path NW3 Nevada-Oregon Border (NOB).

In the event that the hourly California ISO Spinning Reserve Capacity market expires, the Unauthorized Increase Charge for demand shall be the greater of:

a. Three (3) times the applicable monthly demand charge;

b. the sum of hourly or diurnal prices for all HLHs in the month, at a hub at which Northwest parties can trade, established between October 1, 2001, and September 30, 2006.

2. Charge for Unauthorized Increase in Energy

The amount of Measured Energy during a diurnal period of a billing month, day, or hour that exceeds the amount of energy the purchaser is contractually entitled to take during that period shall be billed the greater of:

a. One hundred (100) mills/kWh; or

b. for the month in question, the greater of:

   (1) the highest diurnal DJ Mid-C Index price for firm power; or

   (2) the highest hourly ISO California Supplemental Energy price (NP15).

The DJ Mid-C Index definitions for HLH's (or peak) and LLH's (or offpeak) will be adjusted, as necessary, to be consistent with (comport with) BPA's definitions for HLH and LLH periods.

In the event that either the ISO California Supplemental Energy price index or the DJ Mid-C Index expires, the index will be replaced for purposes of the Unauthorized Increase Charge for energy by:

   (1) the highest price experienced for the month at the CalPX, NW1 (COB);

   (2) the highest price experienced for the month at the CalPX, NW3 (NOB); or

   (3) the highest price experienced for the month from any applicable new hourly or diurnal energy index at a hub at which Northwest parties can trade, established between October 1, 2001, and September 30, 2006.

SECTION III. DEFINITIONS

A. Power Products and Services Offered By the Power Business Line of BPA

1. Actual Partial Service Product – Simple/Complex

The Actual Partial Service Products are core Subscription products that are available to purchasers who have a right to purchase from BPA for their requirements. These products are intended for customers who have contractual or generating resources with firm capabilities and therefore require a product other than Full Service. The Simple and Complex versions of this product category differ in that the Complex version is subject to the Factoring Benchmark tests in the billing process and to potential Excess Factoring Charges. The Simple version encompasses several possible approaches to customer resource declaration, all of which obviate the need for the Factoring Benchmark tests.

2. Block Product

The Block Product is a core Subscription product that is available to purchasers who have a right to purchase from BPA for their requirements. This product is available in HLH and LLH quantities per month, with the hourly amount flat for all hours in such periods.

3. Block Product with Factoring

The Block Product with Factoring is a combination of the Block Product with the core Subscription staple-on product for Factoring Service. Factoring provides the service of distributing Block energy to follow Purchaser hourly load needs to the extent of such Block energy.

4. Block Product with Shaping Capacity

The Block Product with Shaping Capacity is a combination of the Block HLH energy product and the core Subscription staple-on product for Shaping capacity. Shaping capacity allows the customer to preschedule Block energy with some limited shape among HLHs within a contractually specified bandwidth.

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

Power for the purpose of Construction, Test and Start-Up, and Station Service for a generating resource or transmission facility shall be made available to eligible purchasers under the Priority Firm Power (PF-02), New Resources Firm Power (NR-02), and Firm Power Products and Services (FPS-96), rate schedules. Such power is not available for the PF Exchange Program rate, the PF Exchange Subscription rate, and the Residential Load rate.

Construction, Test and Start-Up, and Station Service power must be used in the manner specified below:

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

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

c. Power sold for station service may be purchased at any time following commercial operation of the project. Once the project has been energized for commercial operation, the Purchaser may use station service power for start-up, shutdown, normal operations, and operations during a shutdown period.

d. Power sold for Construction, Test and Start-Up, and Station Service is not available for replacement of lost generation for forced or planned outages or resource underperformance.

6. Core Subscription Products

BPA's Core Subscription Products are described in the BPA Product Catalog. Core Subscription Products are available at the posted rates for customers who have a right to purchase them.

The core products are:

- Actual Partial Service Product – Simple/Complex
- Block Product
- Block Product with Factoring
- Block Product with Shaping Capacity
- Full Service Product

7. Customer System Peak (CSP)

CSP is the largest measured HLH Total Retail Load amount in kilowatts for the billing period.

8. Full Service Product

Full Service is a core Subscription product that is available to purchasers who have a right to purchase from BPA for their requirements. This product is available to customers who either have no resources or whose resources meet the criteria for small, non-dispatchable resources.

9. Industrial Firm Power (IP)

Industrial Firm Power (IP) electric power that BPA will make continuously available to a DSI Purchaser subject to the terms of the Purchaser's power sales contract with BPA. Deliveries may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA. Adjustments as provided in the Purchaser's power sales contract shall be made for power restricted to provide reserves.

10. Load Variance

For core Subscription products, Load Variance is defined as the variability in monthly energy consumption within the BPA customer's system. Through the Load Variance charge under the Full and Actual Partial Service Products, the customer's billing factors will follow actual consumption. Load Variance is not applicable to Block Product purchases. For purposes of pricing and rate tests under Pre-Subscription contracts, the Load Variance charge is deemed to correspond to the PF-96 Load Shaping charge.

11. New Resource Firm Power (NR)

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

a. for any NLSL; and

b. for Firm Power purchased by IOUs pursuant to power sales contracts with BPA.

NR is to be used to meet the Purchaser's firm power load within the PNW. Deliveries of NR may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA.

NR is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeure* events. NR is power where BPA agrees to provide operating reserves in accordance with the standards established by the NERC, WSCC, and the NWPP.

12. Nonfirm Energy (NF)

Nonfirm Energy Power (NF) is energy that is supplied or made available by BPA to a Purchaser under an arrangement that does not have the guaranteed continuous availability feature of Firm Power. NF is sold primarily under the NF rate schedule, NF-02. NF also may be supplied under the NF-02 rate schedule to the WSPP subject to terms and conditions agreed upon by the members participating in the WSPP and in accordance with BPA policy for such arrangements. NF that has been purchased under a guarantee provision in the NF rate schedule shall be provided to the Purchaser in accordance with the provisions of that schedule and the power sales contract if applicable. BPA may make NF available to purchasers both inside and outside the United States.

13. Priority Firm Power (PF)

Priority Firm Power (PF) is electric power (capacity and energy) that BPA will make continuously available for direct consumption or resale by public bodies, cooperatives, and Federal agencies. Utilities participating in the Residential Exchange under section 5(c) of the Northwest Power Act may purchase PF pursuant to their Residential Exchange contracts with BPA. PF is not available to serve NLSLs. Deliveries of PF may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA.

PF is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeure* events. PF is power where BPA agrees to provide operating reserves in accordance with the standards established by the NERC, WSCC, and NWPP.

14. Regulation and Frequency Response

Regulation and frequency response is the generating capacity of a power system that is immediately responsive to Automatic Generation Control (AGC) signals without human intervention. Regulation and frequency response is required to provide AGC response to load and generation fluctuations in an effective manner and to maintain desired compliance with NERC AGC Control Performance.

15. Residential Exchange Program Power

Residential Exchange Program Power is power BPA sells to a Purchaser pursuant to the Residential Exchange Program. Under section 5(c) of the Northwest Power Act, BPA "purchases" power from PNW utilities at a utility's Average System Cost (ASC). BPA then offers, in exchange, to "sell" an equivalent amount of electric power to that customer at BPA's PF rate applicable to exchanging utilities. The amount of power purchased and sold is equal to the utility's eligible residential and small farm load. Benefits must be passed directly to the utility's residential and small farm customers.

16. Slice Product

The Slice product is a power sale based upon an eligible customer's annual net firm requirements load and is shaped to BPA's generation from the FCRPS over the year. The Slice product is not a sale or lease of any part of the ownership of, or operational rights to the FCRPS. Slice purchasers are entitled to a fixed percentage of the energy generated by the FCRPS. The Slice purchaser's percentage entitlements are set by contract. The Slice product includes both service to net requirements firm load as well as an advance sale of surplus power.

B. Definition of Rate Schedule Terms

1. 2002 Contract

A 2002 contract is a contract for service in the FY 2002 through 2006 rate period that is signed after January 1, 1999.

2. Annual Billing Cycle

The Annual Billing Cycle is the 12 months beginning with the customer's first monthly power bill for deliveries in the first billing month starting on or after October 1.

3. Billing Demand

The Purchaser's Billing Demand is the amount of capacity to which the demand charge specified in the rate schedule is applied. When the rate schedule includes charges for several products, there may be a Billing Demand quantity for each product. The calculation of Billing Demand is described in the customer's contract.

4. Billing Energy

The Purchaser's Billing Energy is the amount of energy to which the energy charge specified in the rate schedule is applied. When the rate schedule includes charges for several products, there may be a Billing Energy quantity for each product. Billing Energy is divided into HLH and LLH for this rate period.

5. California Independent System Operator (California ISO)

The FERC regulated control area operator of the ISO transmission grid. Its responsibilities include providing non-discriminatory access to the transmission grid, managing congestion, maintaining the reliability and security of the grid, and providing billing and settlement services. The ISO has no affiliation with any market participant.

6. California ISO Spinning Reserve Capacity

The portion of unloaded synchronized generating capacity, controlled by the California ISO, which is capable of being loaded in 10 minutes, and which is capable of running for at least two hours.

7. California ISO Supplemental Energy

Energy from generating units and other resources which have uncommitted capacity following finalization of the hour-ahead schedules and for which scheduling coordinators have submitted bids to the California ISO at least 30 minutes before the commencement of the settlement period.

8. California Power Exchange (CalPX)

An independent agency responsible for conducting an auction for the generators seeking to sell energy and for loads which are not otherwise being served by bilateral contracts. The CalPX is responsible for scheduling generation in its scheduling (*e.g.,* day-ahead) markets, for determining hourly market clearing prices for its market, and for settlement and billing for suppliers and Utility Distribution Company's (UDC) using its market.

9. Contract Demand

The Contract Demand is the maximum number of kilowatts that the Purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Purchaser.

10. Contract Energy

Contract Energy is the maximum number of kilowatthours that the Purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Purchaser.

11. Control Area

A Control Area is the electrical (not necessarily geographical) area within which a controlling utility operating under all NERC standards has the responsibility to adjust its generation on an instantaneous basis to match internal load and powerflow across interchange boundaries to other Control Areas.

12. Decremental Cost

Unless otherwise specified in a contractual arrangement, Decremental Cost as applied to Nonfirm Energy transactions is defined as:

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

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

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

13. Delivering Party

The entity supplying the capacity and/or energy to be transmitted at Point(s) of Interconnection.

14. Demand Entitlement

For purchases made under contracts for core Subscription products, Demand Entitlement is the largest HLH amount of power in kilowatts that the purchaser is entitled to receive from BPA during the billing period as specified in the contract.

15. Discount Period

The end of the rate period or the customer's contract term, whichever comes first.

16. Dow Jones Mid-C Indexes (DJ Mid-C Indexes)

Average HLH (or peak) and average LLH (or offpeak) price indices for sales of electricity at delivery points along the Mid-Columbia River, as published by Dow Jones & Company, Inc.

17. Electric Power

Electric Power is electric peaking capacity (kilowatts) and/or electric energy (kilowatthours).

18. Energy Entitlement

For purchases made under contracts for core Subscription products, HLH and LLH Energy Entitlement is the sum in kilowatthours of amounts for HLH and LLH energy respectively, that the purchaser is entitled to receive from BPA as specified in the contract.

19. Federal System

The Federal System is the generating facilities of the FCRPS, including the Federal generating facilities for which BPA is designated as marketing agent; the Federal facilities under the jurisdiction of BPA; and any other facilities:

a. from which BPA receives all or a portion of the generating capability (other than station service) for use in meeting BPA's loads to the extent BPA has the right to receive such capability. "BPA's loads" do not include any of the loads of any BPA customer that are served by a non-Federal generating resource purchased or owned directly by such customer which may be scheduled by BPA;

b. which BPA may use under contract or license; or

c. to the extent of the rights acquired by BPA pursuant to the 1961 U.S.-Canada Treaty relating to the cooperative development of water resources of the Columbia River Basin.

20. Firm Power (PF-02, IP-02, NR-02, RL-02)

Firm Power is electric power (capacity and energy) that BPA will make continuously available under contracts executed pursuant to section 5 of the Northwest Power Act.

21. Full Service Customer

A Full Service customer is one who is purchasing power from BPA through the Full Service Product.

22. Generation System Peak (GSP)

The GSP is the hour of the largest HLH output of the Federal System that occurs during the customer's billing period.

23. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all those hours in the peak period hour ending 7 a.m. to the hour ending 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). There are no exceptions to this definition; that is, it does not matter whether the day is a normal working day or a holiday.

24. Inventory Solution

BPA's potential actions to supplement the capability of the Federal System Resources, as a result of BPA's Subscription process. It is currently not known whether an Inventory Solution will be necessary, or what form the Inventory Solution will take.

25. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the offpeak period hour ending 11 p.m. to the hour ending 6 a.m., Monday through Saturday and all hours Sunday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable).

26. Measured Demand

The Purchaser's Measured Demand is that portion of its Metered or Scheduled Demand provided by BPA to the Purchaser. If more than one class of power is delivered to any point of delivery, the portion of the measured quantities assigned to any class of power shall be as specified by contract. Any delivery of Federal power not assigned to classes of power delivered under other agreements shall be included in the Measured Demand for PF, NR, or IP power as applicable.
The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power. Any residual quantity, after determination of the Purchaser's contractual entitlement at a particular rate, is considered "unauthorized." Unauthorized increases are billed in accordance with the provisions of these GRSPs.

In determining Measured Demand for any Purchaser who experiences an outage as defined pursuant to the Purchaser's agreement with BPA, BPA shall adjust any abnormal Integrated Demand due to, or resulting from:

a. emergencies or breakdowns on, or maintenance of, the Federal System Facilities; and

b. emergencies on the Purchaser's facilities to the extent BPA determines that such facilities have been adequately maintained and prudently operated.

BPA will follow its billing process in establishing the Billing Demand should an outage cause an unusual Billing Demand quantity.

BPA will not give outage credits for demand.

27. Measured Energy

The Purchaser's Measured Energy is that portion of its Metered or Scheduled Energy that is provided by BPA to the Purchaser during a particular diurnal period (HLH or LLH) in a billing period. If more than one class of power is delivered to any point of delivery, the portion of the measured quantities assigned to any class of power shall be as specified by contract. Any delivery of Federal power not assigned to classes of power delivered under other agreements shall be included in the Measured Energy for PF, NR, or IP power as applicable. The portion of the total Measured Energy so assigned shall constitute the Measured Energy for each such class of power. Any residual quantity, after determination of the Purchaser's contractual entitlement at a particular rate, is considered "unauthorized." Unauthorized increases are billed in accordance with the provisions of these GRSPs.

28. Metered Demand

The Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour Integrated Demands at which electric energy is delivered to a purchaser:

a. at each point of delivery for which the Metered Demand is the basis for determination of the Measured Demand;

b. during each time period specified in the applicable rate schedule; and

c. during any billing period.

Such largest Integrated Demand shall be determined from measurements made in accordance with the provisions of the applicable contract and these GRSPs. This amount shall be adjusted as provided herein and in the applicable agreement between BPA and the Purchaser.

29. Metered Energy

The Metered Energy for a purchaser shall be the number of kilowatthours that are recorded on the appropriate metering equipment, adjusted as specified in the applicable agreement and delivered to a Purchaser:

a. at all points of delivery for which metered energy is the basis for determination of the Measured Energy; and

b. during any billing period.

30. Monthly Federal System Peak Load

Monthly Federal System Peak Load is the peak load on the Federal System during a customer's billing month, determined by the largest hourly integrated demand produced from system generating plants in BPA's control area and scheduled imports for BPA's account from other control areas.

31. NP15

The portion of the California ISO's control area north of transmission path 15.

32. NW1 (COB)

California PX and California ISO designation for delivery at COB (Captain Jack/Malin).

33. NW3 (NOB)

CalPX and California ISO designation for delivery at NOB.

34. Partial Service Customer

A Partial Service customer is any customer that is not a Full Service customer.

35. Point of Delivery (POD)

A POD is the contractual interconnection point where power is delivered to the customer. Typically, a point of delivery is located at a substation site, but it could be located at the change of ownership point on a transmission line.

36. Point of Integration (POI)

A Point of Integration is the contractual interconnection point where power is received from the customer. Typically a point of integration is located at a resource site, but it could be located at some other interconnection point to receive system power from the customer.

37. Point of Interconnection (POI)

A Point of Interconnection is a point where the facilities of two entities are interconnected.

38. Points of Metering (POM)

The POM shall be those points specified in the contract at which Total Retail Load and Metered Amounts are measured.

39. Pre-Subscription Contract

A contract for service in the FY 2002 through 2006 rate period that was signed prior to January 1, 1999, is a Pre-Subscription Contract.

40. Purchaser

Pursuant to the terms of an agreement and applicable rate schedule(s), a Purchaser contracts to pay BPA for providing a product or service.

41. Receiving Party

The entity receiving the capacity and/or energy transmitted by BPA to a Point(s) of Delivery.

42. Retail Access

Retail Access is non-discriminatory retail distribution access mandated either by Federal or state law which grants retail electric power consumers the right to choose their electricity supplier.

43. Scheduled Demand

For purposes of applying the rates herein to applicable purchases by the Purchaser, the Scheduled Demand in kilowatts is the largest of the hourly demands at which electric energy is scheduled by BPA for delivery to a purchaser:

a. to each system for which Scheduled Demand is the basis for determination of the Measured Demand;

b. during each time period specified in the applicable rate schedule; and

c. during any billing period.

Scheduled Demand is deemed delivered for the purpose of determining Billing Demand.

44. Scheduled Energy

For purposes of applying the rates herein to applicable purchases by the Purchaser, Scheduled Energy in kilowatthours shall be the sum of the hourly demands at which electric energy is scheduled by BPA for delivery to a purchaser:

a. for each system for which Scheduled Energy is the basis for determination of the Measured Energy; and

b. during any billing period.

Scheduled Energy is deemed delivered for the purpose of determining Billing Energy.

45. Slice Revenue Requirement

The Slice Revenue Requirement is comprised of the items in BPA's PBL revenue requirement used to calculate the Slice product charge, as identified in the PBL's 2002 and 2007 Power rate cases. *See* Table D.

46. Subscription

Subscription refers to the Power Subscription Strategy issued by BPA on December 21, 1998, which is BPA's policy for power sales beginning FY 2002.

47. Subscription Contract

See 2002 Contract.

48. Total Plant Load

Total Plant Load means a DSI customer's total electrical energy load at facilities eligible for BPA service during any given time period whether the customer has chosen to serve its load with BPA power or non-Federal power.

49. Total Retail Load (TRL)

Total Retail Load (TRL) is all electric power consumption including distribution system losses, within a utility's distribution system as measured at metering points, adjusted for unmetered loads or generation. No distinction is made between load that is served with BPA power and load that is served with power from other sources. For DSIs, TRL is called Total Plant Load.

The TRL billing determinant for the Load Variance Charge will be adjusted for any load that is designated as exempt from the charge in accordance with the customer's Power Sales Agreement.

50. Utility Distribution Company (UDC)

A company that owns and maintains the distribution facilities used to serve end-use customers.

TABLE E

Inventory Solution True-Up Adjustment

The Inventory Solution True-Up Adjustment (ISTU) is calculated once during each rate period and is calculated in the following manner:

$ISTU_R = (CL_R - FL_R)/ ISMW_R * NCIS_R/12$

Where:

$ISTU_R$ is the Inventory Solution True-Up Adjustment for the rate period R.

CL_R is the annual average Contracted Loads for the rate period R. Contracted Loads for each five-year rate period shall be the average of five Fiscal Year loads contracted for in annual aMW for the Public Agency customers, DSI customers to be served with FBS resources, IOU customers to be served with FBS resources, and the Preexisting Multiyear Contracts that are known to BPA.

FL_R is the annual average Forecasted Loads for the rate period R. Forecasted Loads for each five-year rate period shall be the average of five forecasted Fiscal Year loads in annual aMW that was included in the applicable Final Power Rate Proposal for the Public Agency loads, DSI loads to be served with FBS resources, IOU loads served with FBS resources, and Preexisting Multiyear Contracts.

(CL_R-FL_R) cannot be a value less than zero.

$ISMW_R$ is the annual average MW associated with the Inventory Solution for the rate period R.

$NCIS_R$ is the annual average net cost of the Inventory Solution for the rate period R.

Bonneville Power Administration
Power Business Line

2002 Final Power Rate Proposal

Administrator's Record of Decision

Appendix 2: 1996 Wholesale Power Rate Schedules Adjustment

WP-02-A-02
May 2000

Adjustment to the 1996

BPA

GENERAL RATE SCHEDULE PROVISIONS

FOR POWER RATES

A. Targeted Adjustment Charge for Uncommitted Loads

1. Availability

The Targeted Adjustment Charge for Uncommitted Loads (TACUL) pertains to the PF and NR rate schedules. The TACUL applies after December 7, 2000, to purchases to serve customer loads that were uncommitted during the 1996 rate case which are returned to BPA firm power requirements service during a period prior to FY 2002. Customers subject to the TACUL are those that reduced their purchases from BPA by adding firm resources to serve load under: (1) 1981 power sales contracts that expire on or before July 31, 2001, as may be amended; (2) Amendatory Agreement No. 7 (AA7) to the 1981 power sales contracts, or new “1996” power sales contracts where the customer provides BPA notice after December 7, 1998, consistent with the terms of the customer’s power sales contract, for requirements service for the period prior to FY 2002. Customers who apply after December 7, 2000, for firm requirements load under the NR rate will also be subject to the TACUL. This charge will be in effect through September 30, 2001.

This rate schedule amends the PF-96 and NR-96 rate schedules, which went into effect October 1, 1996.

2. Energy Charge

The TACUL is a monthly mills/kWh adjustment to the HLH and LLH energy rates specified in the 1996 rate schedule, and is applied to that portion of the customer’s load that is subject to the TACUL. The TACUL rate adjustment will be established based on one of the following formula:

$$\text{TACUL} = [(\text{Incr } \$ * \text{Incr Amt}) - (\text{Rate } \$ * \text{Incr Amt})]/\text{TACUL Amt}$$

where:

TACUL Amt	=	The amount of load subject to the TACUL, determined monthly.
Rate $	=	The monthly PF or NR energy rate shown in the applicable rate schedule.
Inventory Amt	=	Amount of energy available to serve this load based on an annual energy Federal system firm resource capability as defined in the Loads and Resources Study, and updated if BPA determines that is necessary.

Incr $ = Monthly cost to BPA, plus a handling fee, of incremental power for HLH and LLH expressed in mills/kWh (see below). These costs also may include where applicable, wheeling, ancillary, and other charges BPA may incur in purchasing power from other entities such as, but not limited to, the California ISO or the CalPX.

Incr Amt = Amount of incremental power required, determined monthly and defined as the TACUL Amt minus the Inventory Amt. (If there is no available Inventory Amt, the Incr Amt will equal the TACUL Amt).

If Incr $ is less than Rate $, the TACUL is 0 mills/kWh.

TACUL is the monthly rate adjustment in mills/kWh.

BPA will calculate the cost (Incr $) per month in mills/kWh of the additional power per month (Incr Amt) for a specific Customer request. BPA will establish the cost of the additional power by the following methods:

a. BPA will establish the price based on BPA's monthly cost to purchase the incremental load by purchases of resources at market, or the monthly cost of BPA recallable power contracts, averaged, whichever is less.

b. A price plus handling fee calculated based on the following index.

BPA will calculate the price per month for HLH and LLH, based on an index calculated according to the following:

Price of HLH = 1/3 HLH (DJ Mid C) + 1/3 HLH (CalPX) + 1/3 (NYMEX Mid C)

Price of LLH = 1/2 LLH (DJ Mid C) + 1/2 LLH (PX) where the CalPX basis is adjusted to DJ Mid C

where:

DJ Mid C = Dow Jones Firm Onpeak (HLH) and Firm Offpeak (LLH) Mid-Columbia Electricity Price Index

California PX = California Power Exchange Day-Ahead Zonal Prices (Constrained)--the average of NW1 (Captain Jack/Malin--COB) and NW3 (NOB) for HLH and LLH

NYMEX Mid C	=	the New York Mercantile Exchange Futures Electricity Closing Price at Mid-C for the applicable month

CalPX prices will be adjusted for basis difference between COB/NOB and the Mid-C using the IS/PTP Rates contained in BPA's 1996 Transmission Rate Schedules.

If the NYMEX Mid-C index does not exist, BPA will use a one-half weighting of the DJ Mid-C and the CalPX.

Errata to
2002 Final Power Rate Proposal
Administrator's Record of Decision
Appendix 2
WP-02-A-02(E1)

Appendix 2, Page 1:	In section A.1: TACUL Availability, first paragraph, second sentence from the end of the paragraph: Replace 2000 with 1998. The sentence now reads "Customers who apply after December 7, 1998, for firm requirements load under the NR rate will also be subject to the TACUL."

Executive Summary of WP-02 Power Rates Record of Decision

5/15/00

The Record of Decision (ROD) of the power rate case contains the decisions of the Bonneville Power Administration (BPA) for the adoption of power rates for the five-year rate period beginning October 1, 2001 through September 30, 2006. This rate proceeding is the pricing aspect of the implementation of BPA's Power Subscription Strategy, adopted December 12, 1998. It includes only power rates, since BPA's Transmission Business Line is conducting their own separate rate proceeding.

Chapters 1 and 2 of the ROD provide the context and policy decisions for this rate proceeding. The ROD incorporates the results of decisions made during the public processes associated with the Business Plan, the Cost Review, the Subscription Strategy, and the Fish and Wildlife Funding Principles. This upcoming rate period presents BPA with a major uncertainty for which BPA had to make assumptions: For example, since the power sales contracts will expire 9/30/01, how many customers will sign new contracts for power, and for how long? Plus, there are unknowns about the level of expenses BPA will have for fish and wildlife obligations and changes to the hydro system.

The rate case adopts the four principal goals of the Subscription Strategy:

- To promote the spread of the benefits of the Federal Columbia River Power System (FCRPS) as broadly as possible, with special attention given to the residential and rural customers of the region;
- To avoid rate increases through a creative and business-like response to markets and additional aggressive cost reductions;
- To allow BPA to fulfill its fish and wildlife obligations while assuring a high level of Treasury payment; and
- To support BPA's role as being a leader in the regional effort to capture the value of conservation and renewable resources.

Chapter 3 of the ROD describes how BPA compiles load and resource data. This is equivalent to BPA's sales and inventory estimates. There are three inter-related components: a federal system load forecast, a federal system resource forecast, and the federal system load and resource balances.

Chapter 4 describes the Marginal Cost Analysis which informs (but does not directly set) the price level at which BPA buys and sells in the bulk power market. Marginal costs are also used in the rate design to help BPA's rates send economic price signals.

Chapters 5, 6, and 7 describe how BPA established its revenue requirements, determined the financial risks, and then developed a risk mitigation package. BPA's Revenue Requirement Study for power is a detailed analysis of the level of revenue from wholesale power rates required to recover all costs of producing, acquiring, marketing, and conserving electric power. BPA has set its rates so that there is an 88% probability that it will make all five payments to the Treasury on time and in full during the rate period.

BPA conducted a number of studies of the financial risks that BPA faces as a consequence of uncertainties. BPA looked at operational risks (such as weather and plant outages) and policy-related non-operational risks (related to uncertainties in revenue or expense levels). BPA then developed an integrated package of risk mitigation measures to account for the uncertainty. This risk mitigation package consists of: 1) starting reserves; 2) credits under the Fish Cost Contingency Fund; 3) a Cost Recovery Adjustment Clause (an automatic, temporary upward adjustment to posted power prices if the actual accumulated net revenues fall below a threshold level); and 4) Planned Net Revenues for Risk (a component of the revenue requirement added to annual expenses that increase cash flows so that financial reserves, in conjunction with the other risk mitigation tools, achieve the Treasury payment goal).

In the event that BPA's actual accumulated net revenues rise beyond a level need to ensure that all costs are covered, BPA has developed a mechanism known as the Dividend Distribution Clause to distribute dividends to customers and potentially to other stakeholders. The details of how to allocate and distribute any dividends among stakeholders will be made in a separate public process, prior to 10/1/01, but BPA has committed to setting aside the first $15 million of any dividends to support conservation and renewable resources.

In **Chapter 8** of the ROD, BPA describes the decisions made regarding transmission and inter-business line issues. The chapter describes how BPA will continue to provide existing General Transfer Agreements to current loads for delivery of federal power through the rate period. These costs will be spread over all BPA power sales. BPA will also provide a limited amount of GTA service or comparable transfer service under an open access tariff for deliveries of federal power to certain new preference customers. This decision was made in the Supplemental Subscription ROD, and reflected in the rates. However, BPA will not provide GTA service to preference customers for deliveries of federal power to annexed load. BPA forecasted the inter-business line revenues and expenses that the Power Business Line will incur during the FY 2002-2006 rate period. The forecasted transmission expenses do not constitute a transmission rate proposal, and will not be binding on any transmission rate case or settlement. However, allocation methodologies for the PBL-supplied generation inputs to the TBL for ancillary services are binding on the TBL.

Chapter 9 states that the Transmission Business Line at BPA will pay up to $6.5 million per year for transmission over third-party systems to deliver non-federal power to customers historically served by GTAs, and will roll those costs into network (transmission) sales.

Chapter 10 contains all the details of rate design. Some of the key issues discussed in this chapter include descriptions of the changes in the calculation and design of wholesale power rates to accommodate the new Subscription contracts, and to reflect cost causation and provide price signals for more efficient use of the Federal Base System (FBS). Some of the major changes described in this chapter are changes to energy and demand charges (12 monthly seasons per year), a new load variance charge, optional stepped rates for the five year rate period, a charge for stepping up block sales amounts over the term on the contract (SUMY), and a Targeted Adjustment Charge on regional firm load that results in an unanticipated increase in BPA's projected loads within the rate period. BPA has also developed a Conservation and Renewable Discount to encourage and support the development of conservation projects and renewable resources in the region.

Chapters 11, 12, and 13 are a technical discussion of the models and assumptions used by BPA as it sets rates for it's various customer groups in compliance with the rate directives in the Northwest Power Act. As part of this ratemaking process, costs associated with the Residential Exchange Program are determined. Those costs and all other power revenue requirement costs are examined in a Cost of Service Analysis and allocated to the various customer loads. These initial allocations of costs are then adjusted in accordance with the Northwest Power Act's rate directives. These rate directives include the Section 7(b)(2) Rate Test, which determines whether BPA's public body and cooperative customers are entitled to rate protection. If the public customers receive rate protection, costs are shifted away from the public customers and absorbed by other customers who purchase firm BPA power. To calculate final Subscription rates, additional ratemaking adjustments were made to allocate Subscription specific costs and credits to the various customer groups.

In **Chapter 14**, the ROD describes the benefits and settlement of service to the Investor Owned Utilities (IOUs). BPA has determined that the rate levels will allow it to provide 1900 aMW to the IOUs, as decided in the Supplemental Subscription ROD. The RL rate, for power the IOUs purchase from BPA for service to their residential and small commercial load, is equal to the PF rate.

Chapter 15 reflects the Compromise Approach discussions in the ROD's description of service to the Direct Service Industrial customers (DSIs). The ROD indicates that BPA will provide service up to 1440 aMW in a firm power block, allocated among DSIs based on each DSI's purchases under the current IP-96 rate. Of that service, 990 aMW is comprised of power priced at a base rate. It is combined with 450 aMW priced to directly reflect the cost of BPA purchasing that power, and results in the IP TAC rates for DSI purchases. BPA will also offer the DSIs a cost-based indexed IP rate option, tied to the price of aluminum.

Chapter 16 describes how BPA intends to offer its preference customers a Slice of the system product. The Slice revenue requirement is comprised of all the line items identified in the 2002 power rate case, with certain limited exceptions. The Slice methodology is described in the Attachment to the ROD. BPA will seek a ten-year approval of that methodology from FERC.

Chapter 17 addresses technical issues related to the rate schedules. In **Chapter 18**, the ROD describes how hundreds of participants to the rate case also helped shape the decisions. BPA held 9 field hearings, and received over 700 comments from the attendees. BPA also received over 6,400 written comments which it analyzed and addressed in the ROD.

Chapter 19 contains a special issue discussed in the 2002 rate case that adjusts the PF-96 and NR-96 rates. The purpose of the Targeted Adjusted Charge for Uncommitted Load (TACUL) is to recover costs BPA may incur to provide firm power requirements service to those customers with loads uncommitted to BPA in the 1996 rate case, and whose current power sales contracts expire on or before July 31, 2000.

The **Appendices** to the ROD are published in a separate volume. They contain the actual rate schedules that will be applied to purchases for the next rate period. BPA has included the 1996 rate schedule adjustment for TACUL as Appendix 2 of that volume.

<u>Next steps?</u>

BPA will file the entire record of the case (as much as 80,000 pages) with the Federal Energy Regulatory Commission (FERC) for review and approval. FERC generally grants interim approval within 60 days of the filing. The rates will be in effect from 10/1/01 until 9/30/06. BPA will ask FERC for a 10-year approval of the Slice methodology.

BPA will also ask FERC for interim approval of the PF-96 adjustment (TACUL) within 60 days, and final approval by January 1, 2001. The rate will expire 9/30/01.

The Record of Decision for the Power Rate Case

Volume 1	Chapters 1 through 9	DOE/BP-3293
Volume 2	Chapters 10 through 13	DOE/BP-3294
Volume 3	Chapters 14 through Slice Attachment	DOE/BP-3295
Appendices	Rate Schedules	DOE/BP-3296