

# 2002 Supplemental Power Rate Proposal Administrator's Final Record of Decision

WP-02-A-09

June 2001



**2002 Supplemental Power Rate Proposal  
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**APPENDIX**

2002 Revised General Rate Schedule Provisions (GRSPs)

## ACRONYM LIST

ALJ	Administrative Law Judge
AANR	Actual Accumulated Net Revenues
Alcoa	Alcoa, Inc.
Amended Proposal	2002 Amended Power Rate Proposal
aMW	Average Megawatt
ANR	Accumulated Net Revenue
ANRT	Accumulated Net Revenue Threshold
APA	Administrative Procedures Act
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
C&R Discount	Conservation and Renewables Discount
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAL	Columbia Falls Aluminum Company
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRITFC	Columbia River Inter-Tribal Fish Commission
CT	Combustion Turbine
CWA	Clear Water Act
CY	Calendar Year (Jan-Dec)
DDC	Dividend Distribution Clause
DJ	Dow Jones
DOE	Department of Energy
Draft Supplemental ROD	Draft Supplemental 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
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
FACA	Federal Advisory Committee Act
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
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
Final Report	Comprehensive Review of the Northwest Energy System, Final Report, December 12, 1996
Final Supplemental ROD	Administrator's Final ROD for BPA's 2002 Wholesale Power Rates
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FRN	Federal Register Notice
FY	Fiscal Year (Oct-Sep)
GCPs	General Contract Provisions
GEP	Green Energy Premium
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GTA	General Transfer Agreement
GWh	Gigawatthour
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.
IERA	Indian Energy Resources Act
IPC	Idaho Power Company
IP	Industrial Firm Power (rate)
IPTAC	Industrial Firm Power Targeted Adjustment Charge
IOU	IOU (the joint IOU filings)
IOUs	Investor-Owned Utilities
ISO	Independent System Operator
JCG	Joint Customer Group
JOA	Joint Operating Agency
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kW	Kilowatt (1000 watts)
kWh	Kilowatthour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LDD	Low Density Discount

LLH	Light Load Hour
L/R Balance	Load/Resource Balance
m/kWh	Mills per kilowatthour
MAC	Market Access Coalition Group
MAF	Million Acre Feet
May Proposal	May 2000 Final Power Rate Proposal
MC	Marginal Cost
MCA	Marginal Cost Analysis
Mid-C	Mid-Columbia
MMBTU	Million British Thermal Units
MOA	Memorandum of Agreement
MPC	Montana Power Company
MW	Megawatt (1 million watts)
MWh	Megawatthour
NCD	Non-coincidental Demand
NEPA	National Environmental Policy Act
NF	Nonfirm Energy (rate)
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
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWEC	Northwest Energy Coalition
NWPP	Northwest Power Pool
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)
PBL	Power Business Line
PF	Priority Firm Power (rate)
PGE	Portland General Electric
PGP	Public Generating Pool
PMA	Power Marketing Agencies
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)
Reclamation	Bureau of Reclamation
Regional Preference Act	Pacific Northwest Regional Power Preference Act (Pub.L. 88-552) 1964
Renewable Northwest	Renewable Northwest Project
REP	Residential Exchange Program
REP Settlements	Residential Exchange Program Settlements
REP Settlement ROD	Administrator’s Record of Decision, October 2000
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
Rule 1010	Rules of Procedure 1010
RTO	Regional Transmission Organization
SCCT	Single-Cycle Combustion Turbine
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
SOS	Save Our Wild Salmon
SUB	Springfield Utility Board
Subscription ROD	Power Subscription Strategy Administrator’s ROD
SUMY	Stepped-Up Multiyear
Supplemental Proposal	2002 Supplemental Power Rate Proposal
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TACUL	Targeted Adjustment Charge for Uncommitted Loads
TBL	Transmission Business Line
TPP	Treasury Payment Probability
TRL	Total Retail Load
UAI Charge	Unauthorized Increase Charge
UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service



Vanalco	Vanalco, Inc.
VOR	Value of Reserves
WAPA	Western Area Power Administration
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
Yakama	Confederated Tribes and Bands of the Yakama Nation

## 1.0 INTRODUCTION

This Supplemental Record of Decision (Supplemental ROD) contains the decisions of the risk mitigation measures proposed by the Bonneville Power Administration (BPA), based on the record compiled to date, with respect to the adoption of power rates for the five-year rate period commencing October 1, 2001, through September 30, 2006. This Supplemental Power Rate Proposal is the implementation of the methodology developed through the Cost Recovery Adjustment Clauses (CRAC) that assures sufficient cost recovery in light of the additional load placed on BPA and the escalating, volatile western power markets. This supplemental proceeding also made some corresponding modifications to the Slice methodology and adjusts the Rate Case Market Price Forecast for Investor-Owned Utilities' (IOUs) Residential Exchange Program (REP) Settlements.

This Supplemental ROD follows a full evidentiary hearing, briefing, and oral argument before the BPA Administrator. Chapters 2 through 9 present the issues raised by parties to this proceeding, the parties' positions, BPA staff's positions on the issues, an evaluation of the positions, and the Administrator's decisions.

### 1.1 Background

#### 1.1.1 The Comprehensive Review of the Northwest Energy System

In early 1996, the governors of Idaho, Montana, Oregon, and Washington convened the Comprehensive Review of the Northwest Energy System to seize opportunities and moderate risks presented by the transition of the region's power system to a more competitive electricity market. *See* Comprehensive Review of the Northwest Energy System, Final Report, December 12, 1996 (Final Report). The governors appointed a 20-member Steering Committee that was broadly representative of the various stakeholders in the power system to study the system and make recommendations about its transformation. *Id.* Each governor had a representative on the Steering Committee to make certain the public was educated about and involved in the Comprehensive Review. *Id.* In establishing the review, the governors stated:

The goal of this review is to develop, through a public process, recommendations for changes in the institutional structure of the region's electric utility industry. These changes should be designed to protect the region's natural resources and distribute equitably the costs and benefits of a more competitive marketplace, while at the same time assuring the region of an adequate, efficient, economical and reliable power system. In 1996, the Steering Committee held 30 day-long meetings. In addition, almost 400 people were involved in more than 100 meetings of various work groups reporting to the Steering Committee. Hundreds of citizens attended the 10 public hearings that were held throughout the region on the Committee's draft report. More than 700 written comments were received. The Final Report was the product of that work.

*Id.*

The Final Report noted that the electricity industry in the United States is in the midst of significant restructuring. *Id.* This restructuring is the product of many factors, including national policy to promote a competitive electricity generation market and state initiatives in California, New York, New England, Wisconsin, and elsewhere to open retail electricity markets to competition. *Id.* This transformation is moving the industry away from the regulated monopoly structure of the past 75 years. *Id.* Today the region is served by individual utilities, many of which control everything from the power plant to the delivery of power to the region's homes or businesses. *Id.* In the future, the region may have a choice among power suppliers that deliver their product over transmission and distribution systems that are operated independently as common carriers. *Id.* There is much to be gained in this transition. *Id.* Broad competition in the electricity industry that extends to all consumers could result in lower prices and more choices about the sources, variety, and quality of their electrical service. *Id.*

The Final Report also noted that there are risks inherent in the transition to more competitive electricity services. *Id.* Merely declaring that a market should become competitive will not necessarily achieve the full benefits of competition or ensure that they will be broadly shared. *Id.* It is entirely possible to have deregulation without true competition. *Id.* Similarly, the reliability of the region's power supply could be compromised if care is not taken to ensure that competitive pressures do not override the incentives for reliable operation. *Id.* How competition is structured is important. *Id.* It is also important to recognize the limitations of competition. *Id.* Competitive markets respond to consumer demands, but they do not necessarily accomplish other important public policy objectives. *Id.* The Northwest has a long tradition of energy policies that support environmental protection, energy efficiency, renewable resources, affordable services to rural and low-income consumers, and fish and wildlife restoration. *Id.* These public policy objectives remain important and relevant. *Id.* The Final Report states that given the enormous economic and environmental implications of energy, these public policy objectives need to be incorporated into the rules and structures of a competitive energy market. *Id.*

The Final Report stated that, in some respects, the transition to a competitive electricity industry is more complicated in the Northwest because of the presence of BPA. *Id.* BPA is a major factor in the region's power industry, supplying, on average, 40 percent of the power sold in the region and controlling more than half the region's high-voltage transmission. *Id.* BPA benefits from the fact that it markets most of the region's low-cost hydroelectric power. *Id.* It is hampered by the fact that it has high fixed costs, including the cost of past investments in nuclear power and the majority of the costs for salmon recovery. *Id.* As a wholesale power supplier, BPA is already fully exposed to competition and is struggling to reduce its costs so that it can compete in the market. *Id.* The transition to a competitive electricity industry raises many issues for the BPA and the region. *Id.* In the near term, how can BPA continue to meet its financial and environmental obligations in the face of intense competitive pressure? *Id.* In the longer-term, when market prices rise and some of BPA's debt obligations have been retired, how can the Northwest retain the economic benefits of its low-cost hydroelectric power when the rest of the country is paying market prices? *Id.* And finally, what is the appropriate role of a federal agency in a competitive market? *Id.*

The Final Report noted that while participants on the Comprehensive Review Steering Committee represented, by design, many divergent interests, they were fundamentally interconnected through one unifying value. *Id.* Collectively, they share an abiding interest in the stewardship of a great regional resource—the Columbia River and its tributaries. *Id.* The river is the link that brought all the parties together and unites them in a single, overriding goal. *Id.* That goal is to protect and enhance the assets of this great natural resource for the people of the Pacific Northwest. *Id.*

The Final Report stated that the federal power system in the Pacific Northwest has conferred significant benefits on the region for more than 50 years. *Id.* The availability of inexpensive electricity at cost has supported strong economic growth and helped provide for other uses of the Columbia River, such as irrigation, flood control and navigation. *Id.* The renewable and non-polluting hydropower system has helped maintain a high quality environment in the region. *Id.* But while the power system has produced significant benefits, these benefits came at a substantial cost to the fish and wildlife resources of the Columbia River basin. *Id.* Salmon and steelhead populations had been reduced to historic lows, and many runs were about to be listed under the Federal Endangered Species Act. *Id.* Resident fish and wildlife populations had also been affected. *Id.* Native Americans and fishery-dependent communities, businesses, and recreationists had suffered substantial losses due in significant part to construction and operation of the power system. *Id.* The region's ability to sustain its core industries, support conservation and renewable resources, and restore salmon runs would be clearly threatened if the region could not reach a consensus regional position to bring to the national electricity restructuring debate. *Id.* Without a sustainable and financially healthy power system, funding for fish and wildlife restoration could be jeopardized. *Id.*

The Final Report noted that the governors of Idaho, Montana, Oregon, and Washington, in their charge to the Comprehensive Review, and the Steering Committee in their deliberations, recognized that the electricity industry is changing, whether the region likes it or not. *Id.* The Comprehensive Review was not an initiation of change, but a response to change. *Id.* It was an effort to shape that change, to the extent shaping is possible, to ensure that the potential benefits of competition are achieved and equitably shared, environmental goals are met, and the benefits of the hydroelectric system are preserved for the Northwest. *Id.* The region's ability to shape the change in the Northwest electricity industry depends on its ability to develop a regional consensus. *Id.* If the Comprehensive Review failed to result in a consensus for regional action, the electricity industry would still be restructured. *Id.* A return to the historical industry structure is not an option. *Id.* Many of the comments received during the public hearing process on the Steering Committee's draft recommendations made it clear that this was not a widely appreciated fact. *Id.*

The Final Report summarized the Steering Committee's goals and proposals. The Steering Committee's goals for federal power marketing were to: (1) align the benefits and risks of access to existing federal power; (2) ensure repayment of the debt to the U.S. Treasury with a greater probability than currently exists while not compromising the security or tax-exempt status of BPA's third-party debt; and (3) retain the long-term benefits of the system for the region. *Id.* The recommendation was also intended to be consistent with emerging competitive markets and regional transmission solutions. *Id.* The mechanism proposed to accomplish these

goals was a subscription system for purchasing specified amounts of power at cost with incentives for customers to take longer-term subscriptions. *Id.* Public utility customers with small loads would be able to subscribe under contracts that would accommodate minor load growth. *Id.* Subscriptions would be available first to regional customers in a specified multiparty priority order, starting with preference customers, then the DSIs and the residential and small farm customers of the IOUs participating in the REP, followed by other regional customers. *Id.* Non-regional customers could subscribe after in-region customers. *Id.* Within each phase of the subscription process, longer-term contracts would have priority over shorter-term contracts if the system were oversubscribed. *Id.*

With regard to the REP, the Final Report noted that as a result of passage of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) in 1980, northwest utilities have the right to sell to BPA an amount of power equal to that required to serve their residential and small farm customers at the utilities' average system costs and receive an equal amount of power at BPA's average system cost. *Id.* This was intended to be a mechanism to share the benefits of the low-cost federal hydropower system with the residential and small farm customers of the region's IOUs. *Id.* As a result of decisions made by BPA in its 1996 rate case, those benefits were reduced. *Id.* The Steering Committee acknowledged that the residential and small farm consumers of exchanging IOUs would be adversely affected by the reduction of exchange benefits. *Id.* Congress intervened for one year to stabilize the exchange benefits. *Id.* However, on October 1, 1997, there would be rate increases to the residential and small farm customers of the exchanging utilities. *Id.* The Steering Committee encouraged the parties to continue settlement discussions and to explore other paths to ensure that residential and small farm loads receive an equitable share of federal benefits. *Id.*

### **1.1.2 Bonneville Power Administration's Power Subscription Strategy**

The concept of power subscription came from the Comprehensive Review of the Northwest Energy System, which, as noted above, was convened by the governors of Idaho, Montana, Oregon, and Washington to assist the Northwest through the transition to competitive electricity markets. The Final Report recommended that BPA capture and deliver the low-cost benefits of the federal hydropower system to Northwest energy customers through a subscription-based power sales approach. In early 1997, the Governor's representatives formed a Transition Board to monitor, guide, and evaluate progress on these recommendations.

Public process is integral to BPA's decisionmaking. With the changing marketplace for electric power, there is considerable regional interest in defining how and to whom the region's federal power should be sold. The public was involved at several levels during the development of BPA's Power Subscription Strategy. In addition to the public meetings held specifically on Subscription, BPA sought input from a wide range of interested and affected groups and individuals. BPA collaborated with northwest Tribes, interest groups, Congressional members, the Department of Energy (DOE), the Administration, and BPA's customers to resolve issues, understand commercial interests, and develop strong business relationships.

In early 1997, BPA and the Pacific Northwest Utilities Conference invited 2,800 interested parties throughout the Pacific Northwest to help further define Subscription. The collaborative

effort to design a Subscription contract process began with a public kickoff meeting on March 11, 1997. At this meeting, a BPA/customer design team presented a proposed work plan, including a description of the environmental coverage for Subscription. An important element of the work plan was the formation of a Subscription Work Group. The Federal Power Subscription Work Group, which generally met in Portland twice a month from March 1997, through September 1998, was open to the public. On average, 40-45 participants—representing customers, customer associations, Tribes, State governments, public interest groups, and BPA—attended. Three subgroups formed to more intensely pursue the resolution of issues involving business relationships, products and services, and implementation.

Over 18 months, BPA, its customers and other interested parties discussed and clarified many Subscription issues. During this time, BPA and the public confirmed goals, defined issues, developed an implementation process for offering Subscription, and developed proposed product and pricing principles. The following is a chronology of events.

On March 11, 1997, a public meeting was held in Portland to kick off the Federal Power Marketing Subscription development process. The following topics were discussed at this meeting: the role of the Regional Review Transition Board in the Subscription process; the Draft Work Plan that was developed to guide the development process; the issues that relate to the Subscription process that need to be addressed; and the National Environmental Policy Act (NEPA) strategy for this effort. The Work Plan identified a “self-selected” work group to lead this effort (*i.e.*, anyone was eligible to participate).

On March 18, 1997, the Federal Power Marketing Subscription web site was established at BPA to help disseminate information about the Subscription Process.

On March 19, 1997, the Federal Power Subscription Work Group held its first meeting in Portland, Oregon. The Work Group held a total of 33 meetings (approximately two per month), ending on September 22, 1998.

On September 9, 1997, a Progress Report was presented to the Transition Board.

On November 25, 1997, an update meeting for stakeholders was held in Spokane to discuss progress to date and next steps. A summary of the meeting, along with the meeting handout/slide presentation and concerns/issues raised, was posted to the web site.

In January 1998, an article entitled Subscription Process Underway was published in the BPA Journal (January 1998).

On April 30, 1998, BPA’s Power Business Line (PBL) established a web site to disseminate information about a customer group’s Slice of the System Proposal. The Slice proposal was evaluated by the Subscription Work Group, and the proposal as modified by BPA continued to be developed in a subgroup through January 1999. BPA’s pricing of the Slice product was part of BPA’s initial power rate proposal and was also included in BPA’s 2002 Final Power Rate Proposal, Administrator’s Record of Decision (May ROD), WP-02-A-02.

In June 1998, as part of the Issues '98 process, BPA published Issues '98 Fact Sheet #3: Power Markets, Revenues, and Subscription. Issues '98 (June/Oct. 1998). The fact sheet discussed implementation approaches being considered by the Subscription Work Group so participants in the Issues '98 process could comment. As part of Issues '98 BPA conducted a series of meetings around the region. Issues related to Subscription were key topics in the discussions at those meetings. The public comment period for Issues '98 closed June 26, 1998.

On June 8, 1998, BPA's PBL established a web site to disseminate information about development of the power rates that would be used in the Subscription contracts beginning October 1, 2001. Preliminary discussions regarding development of the power rates occurred in a series of informal public meetings and continued in workshops before BPA's initial proposal was published in early 1999.

On June 18, 1998, the third Subscription public meeting was held in Spokane to present, discuss, and collect comments on the various components related to Subscription. The slide presentation and summary of the meeting were posted to the web site.

On September 18, 1998, BPA released its Power Subscription Strategy Proposal for public comment. Accompanying the proposal was a press release entitled Spreading Federal Power Benefit and a Keeping Current publication entitled Getting Power to the People of the Northwest, BPA's Power Subscription Proposal for the 21st Century. On September 25th, an electronic version of the BPA Power Product Catalog was posted to the web site.

On September 22, 1998, the Federal Power Subscription Work Group held its final meeting in Portland, Oregon.

Subscription issues were discussed at the Columbia River Power and Benefits conference on September 29, 1998, in Portland, Oregon. Over 250 people attended. Conference notes were posted to BPA's web site.

On September 30, 1998, BPA's Energy Efficiency organization established a web site to help disseminate information on the proposal for a Conservation and Renewables Discount. Development of the discount continued in a series of meetings through January 1999. Development of the discount was part of BPA's initial power rate proposal and was also included in the May ROD, WP-02-A-02.

The public was invited to participate in two comment meetings on the Subscription Proposal; one in Spokane, Washington, on October 8, 1998; the other in Portland, Oregon, on October 14, 1998.

BPA developed the Power Subscription Strategy Proposal after considering the efforts of the Subscription Work Group, public comments on Subscription, and the broad information from Issues '98. The proposal incorporated the information received from customers, Tribes, fish and wildlife interest groups, industries, and other constituents. It laid out BPA's strategy for retaining the benefits of the Federal Columbia River Power System (FCRPS) for the Pacific Northwest after 2001. The comment period on the proposal closed October 23, 1998, although

all comments received after that date were considered in the Power Subscription Strategy ROD and the NEPA ROD.

During the spring and summer of 1998, BPA conducted extensive public meetings with all interested parties regarding the development of BPA's Power Subscription Strategy. At the conclusion of these lengthy discussions, on September 18, 1998, BPA released a Power Subscription Strategy Proposal for public review. During the comment period BPA received nearly 200 responses to the proposal comprising nearly 600 pages of comments. After review and analysis of these comments, BPA published its final Power Subscription Strategy on December 21, 1998. *See* Power Subscription Strategy and Power Subscription Strategy, Administrator's ROD. At the same time, the Administrator published a NEPA ROD that contained an environmental analysis for the Power Subscription Strategy. This NEPA ROD was tiered to BPA's Business Plan ROD (August 15, 1995) for the Business Plan Environmental Impact Statement (DOE/EIS-0183, June 1995). The purpose of the Subscription Strategy is to enable the people of the Pacific Northwest to share the benefits of the FCRPS after 2001 while retaining those benefits within the region for future generations.

The Subscription Strategy also addresses how those who receive the benefits of the region's low-cost federal power should share a corresponding measure of the risks. The Subscription Strategy seeks to implement the subscription concept through contracts for the sale of power and the distribution of federal power benefits in the deregulated wholesale electricity market. The success of the Subscription process is fundamental to BPA's overall business purpose to provide public benefits to the Northwest through commercially successful businesses.

The Subscription Strategy is premised on BPA's partnership with the people of the Pacific Northwest. BPA is dedicated to reflecting their values, to providing them benefits and to expanding and spreading the value of the Columbia River throughout the region. In this respect, the Strategy had four goals:

Spread the benefits of the FCRPS as broadly as possible, with special attention given to the residential and rural customers of the region;

Avoid rate increases through a creative and businesslike response to markets and additional aggressive cost reductions;

Allow BPA to fulfill its fish and wildlife obligations while assuring a high probability of U.S. Treasury payment; and

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.

The Power Subscription Strategy describes BPA's decisions on a number of issues. These include the availability of federal power, the approach BPA will use in selling power by contract with its customers, the products from which customers can choose, and frameworks for pricing and contracts. The Power Subscription Strategy discussed some issues that would not be finally



decided in the Strategy. Most of these issues would be decided in BPA's 2002 power rate case, although some were decided in other forums, such as the transmission rate case, which concluded in the summer of 2000. For example, while the Strategy documents BPA's intention to implement a rate discount for conservation and renewable resources, the final design of that discount is developed in BPA's 2002 power rate case. Other issues to be decided in the 2002 power rate case include the design and application of the CRAC, which rates apply to which sales, and the design of the Low Density Discount (LDD). Customers raised issues regarding the application of other customers' non-federal resources to serve regional load. These resource issues involve factual determinations under section 3(d) of the Act of August 31, 1964, P.L. 88-552 (Regional Preference Act), and section 9(c) of the Northwest Power Act, 16 U.S.C. § 839f(c) (1994 & Supp. III 1997), which BPA could not address in the Power Subscription Strategy and which were not made a part of the decisions in the Subscription Strategy ROD.

While BPA's Power Subscription Strategy did not establish any rates or rate designs, rate design approaches identified in the Power Subscription Strategy were part of BPA's initial power rate proposal, which was published in 1999. The comments received during the Subscription public process regarding the various rate-related issues are addressed in BPA's 2002 power rate case, which includes extensive opportunities for public involvement.

BPA's Power Subscription Strategy provided a framework for BPA's 2002 power rate case and Subscription power sales contract negotiations. The Subscription window was to remain open 120 days after the May ROD was signed by the BPA Administrator, providing relatively certain information to potential purchasers regarding rates.

One element of the Power Subscription Strategy proposal was a settlement of the REP for regional IOUs for the post-2001 period. The Power Subscription Strategy proposed that IOUs may agree to a settlement of the REP in which they would be able to receive benefits equivalent to a purchase of a specified amount of power under Subscription for their residential and small farm consumers at a rate expected to be approximately equivalent to the PF Preference rate. Under the proposed settlement, residential and small farm loads of the IOUs would be assured access to the equivalent of 1,800 average megawatts (aMW) of federal power for the Fiscal Year (FY) 2002-2006 period and 2,200 aMW of federal power for the FY 2007-2011 period.

The Power Subscription Strategy noted that BPA would set the physical and financial components of the Subscription amount, by year, in the negotiated Subscription settlement contracts. Any cash payment would reflect the difference between the market price of power forecasted in the rate case and the rate used to make such Subscription sales. The actual power deliveries for these loads would be in equal hourly amounts over the period.

The Power Subscription Strategy proposed that BPA would offer 5-year and 10-year Subscription settlement contracts for the IOUs. Under both contracts, the Subscription Strategy proposed that BPA would offer and guarantee 1,800 aMW of power and/or financial benefits for the FY 2002-2006 period. At least 1,000 aMW would be met with actual BPA power deliveries. The remainder could be provided through either a financial arrangement or additional power deliveries, depending on which approach was most cost-effective for BPA. The IOUs' settlement of rights to request REP benefits under section 5(c) of the Northwest Power Act

would be in effect until the end of the contract term. *See* 16 U.S.C. § 839c(c) (1994 & Supp. III 1997).

Under the 10-year settlement contract, in addition to the benefits provided during the first five years, BPA proposed to provide 2,200 aMW of power or financial benefits for the FY 2007-2011 period. The IOUs' settlement of rights to request REP benefits under section 5(c) would be in effect until the end of the 10-year term of the contract. In the event of reduction of federal system capability and/or the recall of power to serve its public preference customers during the terms of the 5-year and 10-year contracts, BPA would either provide monetary compensation or purchase power to provide power deliveries.

In summary, residential and small farm loads of the IOUs were able to receive benefits from the federal system through one of two ways. An IOU could participate in the established REP or it could participate in a settlement of the REP through Subscription. If an IOU chose to request REP benefits under section 5(c), then the Subscription settlement amount for all the IOUs would be reduced by the amount that would have gone to the exchanging utility.

### **1.1.3 Power Subscription Strategy Supplemental Record of Decision**

As noted above, on December 21, 1998, the BPA Administrator issued a Power Subscription Strategy and accompanying ROD, which set the agency's PBL on a course to establish power rates and offer power sales contracts in anticipation of the expiration of current contracts and rates on September 30, 2001. The Strategy and ROD were the culmination of many public processes that came together to form the framework to equitably distribute in the Pacific Northwest the electric power generated by the FCRPS.

BPA's 1998 Power Subscription Strategy served to guide BPA in accomplishing its goals. After adoption of the Strategy, however, developments occurred that prompted BPA to seek, in some instances, additional comment from customers and constituents on new issues. The Strategy contemplated further public processes to implement its goals. The initial phase of BPA's 2002 power rate case, began in August 1999. BPA and its customers continued discussions on power products and power sales contract prototypes, and the Slice of System product was further defined. In a December 2, 1999, letter, BPA sought comment from customers and constituents on some of these new issues, specifically, the length of the Subscription window for power sales contract offers, the actions required of new small utilities during this window to qualify for firm power service, and new developments with respect to General Transfer Agreements. Other issues arose independently, such as New Large Single Loads under the Northwest Power Act, duration of the new power sales contracts, and a new contract clause regarding corporate citizenship. BPA also undertook a comment process on the amount and allocation of power and financial benefits to provide the IOUs on behalf of their residential and small farm consumers. On November 17, 1999, BPA sent a letter to all interested parties requesting comments on two specific issues: (1) whether the amount of the proposed IOU settlement should be increased by 100 aMW from 1,800 aMW to 1,900 aMW for the FY 2002-2006 period; and (2) the manner in which the settlement amount should be allocated among the individual IOUs. After review of the comments, BPA found the arguments for increasing the IOU settlement amount by 100 aMW to be compelling. Therefore, BPA increased the amount of total benefits for the proposed

settlements of the REP with regional IOUs from 1,800 aMW to 1,900 aMW. BPA also determined specific allocation amounts that would be incorporated into the proposed REP settlement contracts with the individual IOUs.

#### **1.1.4 Bonneville Power Administration's Section 5(b)/9(c) Policy**

As BPA recognized that its existing long-term power sales contracts would soon expire, BPA proposed to establish a policy to guide the agency in making determinations of the net requirements of its utility customers in order to offer federal power under new contracts. (For the most part, existing power sales contracts expire by October 1, 2001.) A net requirements policy is an important component to BPA's execution and implementation of new power sales contracts. Under section 5(b)(1) of the Northwest Power Act, BPA is obligated to offer a contract to each requesting public body, cooperative, and IOU to meet each utility's regional firm load net of the resources used by the utility to serve its firm power consumer load. 16 U.S.C. § 839c(b)(1) (1994 & Supp. III 1997). In making this determination, BPA has a corresponding duty to apply the provisions of section 9(c) of the Northwest Power Act, 16 U.S.C. § 839f(c) (1994 & Supp. III 1997), and section 3(d) of the Regional Preference Act, 16 U.S.C. § 837b(d) (1994 & Supp. III 1997).

BPA provided two opportunities for public review and comment in developing its proposed policy. On May 6, 1999, BPA published its initial policy proposal, entitled Opportunity for Public Comment Regarding Bonneville Power Administration's Subscription Power Sales to Customers and Customer's Sale of Firm Resources, 64 Fed. Reg. 24,376 (1999). BPA held two public meetings to discuss this policy. The first meeting was held on May 27, 1999, in Spokane, Washington. The second meeting was held on June 2, 1999, in Portland, Oregon. On June 3, 1999, the 30-day comment period was extended by BPA through June 30, 1999.

After reviewing and considering the comments received on the initial policy proposal, particularly those that requested that BPA provide a second round of review and comment, BPA issued a revised policy proposal on October 28, 1999, entitled Revised Draft Policy Proposal Regarding Subscription Power Sales to Customers and Customer's Sales of Firm Resources, 64 Fed. Reg. 58,039 (1999). BPA reviewed and considered the comments received on the revised policy. On May 24, 2000, BPA issued its final Policy on Determining Net Requirements of Pacific Northwest Utility Customers under Sections 5(b)(1) and 9(c) of the Northwest Power Act, also called BPA's Section 5(b)/9(c) Policy. BPA also issued a Section 5(b)/9(c) Policy ROD.

#### **1.1.5 Investor-Owned Utilities Settlement Agreements**

After completion of the May ROD, BPA began the development of a prototype RPSA and a prototype Settlement Agreement. On May 5, 2000, BPA sent a letter to all interested parties requesting comments on the proposed agreements. After receiving and reviewing public comments on the IOU Settlement Agreements, BPA issued the Administrator's Record of Decision, Residential Exchange Program Settlement Agreements With Pacific Northwest Investor-Owned Utilities on October 4, 2000. The Settlement Agreement ROD addressed all of the arguments raised by the commenting parties and led to BPA's offer of Residential Exchange

Program Settlement Agreements and RPSAs to Pacific Northwest IOUs. The proposed Settlement Agreements were executed by the IOUs and BPA in the fall of 2000.

## **1.2 Bonneville Power Administration's 2002 Wholesale Power Rate Case**

BPA's 2002 wholesale power rate case is developing power rates for the five-year rate period commencing October 1, 2001, through September 30, 2006. BPA's 2002 Wholesale Power Rate Adjustment Proceeding is the forum for 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 BPA's section 7(i) hearings.

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. 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 on 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. The Final ROD was signed by the Administrator on May 10, 2000.

## **1.3 Procedural History of this Rate Proceeding**

### **1.3.1 Summer 2000**

On July 6, 2000, pursuant to section 7(a)(2) of the Northwest Power Act, BPA filed its proposed rate adjustments for its wholesale power rates with the Federal Energy Regulatory Commission (FERC). 16 U.S.C. § 839e(a)(2). On August 4, 2000, BPA filed a motion with FERC requesting a stay of review of the rate filing for 30 days. Thereafter, BPA reviewed events during the summer months which indicated that power markets on the West Coast had become more volatile than previously anticipated.

BPA concluded that, in light of the unprecedented price spikes during the summer months, BPA's cost-based rates for 2002-2006 would be far more attractive to prospective customers than market alternatives. As a result, preference customers could be expected to purchase significantly more power than originally anticipated. During the initial phase of the rate case,

BPA's load forecast exceeded BPA's forecast of generation resources, requiring BPA to purchase 1,745 aMW of system augmentation. BPA now expects loads will exceed the original rate case forecast, requiring BPA to purchase an additional 1,560 aMW of system augmentation. Total system augmentation purchases for the five-year rate period are forecasted to average 3,305 aMW. Moreover, the difficulty of forecasting the expense of serving the increased load obligations is magnified by the fact that prices are escalating in an extraordinarily volatile market.

The combination of an unanticipated increase in loads with higher and more uncertain market prices greatly diminishes the probability that the rates proposed in the initial phase will fully recover generation function costs. Absent a change to the proposed rates, BPA's Treasury Payment Probability (TPP) is significantly reduced. By law, BPA's payments to Treasury are the lowest priority of revenue application, meaning that such payments are the first to be missed if reserves are insufficient to pay all bills on time. For this reason, BPA expresses its cost recovery goal in terms of probability of being able to make Treasury payments on time. A TPP that is too low reflects an unacceptable degree of financial risk for BPA and the Treasury.

The increased load obligations that BPA will be meeting through market purchases in a currently escalating and volatile market environment have decreased TPP to an unacceptable level. BPA is also implementing the Fish and Wildlife Principles (Principles) in this rate proposal. Among other provisions, the Principles call for a TPP goal of 88 percent, and an acceptable range of 80 to 88 percent for the five-year, FY 2002-2006 rate period. The rates and risk mitigation tools were initially developed to achieve the TPP goal of 88 percent in full. After the rates were filed at FERC, increases and uncertainty surrounding augmentation purchase costs drove the TPP estimate to well below 70 percent.

To ensure that TPP fell within the acceptable range, in early August 2000, BPA began to explore options to solve its cost recovery problem. On August 1, 2000, BPA suspended the signing of any new power contracts with customers and initiated a separate public process to examine the problem and explore potential solutions. On August 3, 2000, BPA wrote a letter to rate case parties and other interested entities in the region, outlining two possible alternatives for dealing with the problem. The first alternative entailed modifying a five-year rate lock provision in BPA's power contracts to give BPA the ability to reset rates if necessary after September 30, 2003. The second alternative involved modifying the 2002 rate filing to address the problem. The letter requested written comment regarding the proposed alternative or any other ideas the parties had for addressing the problem.<sup>1</sup> In addition, BPA set August 9, 2000, for a technical discussion of the issues facing BPA and August 21, 2000, for a public meeting to discuss the range of options.

BPA received over 60 written comments in response to its August 3 letter. On August 31, 2000, after the public meeting, BPA wrote a second letter to rate case and other interested parties. After consideration of all the comments and BPA's own internal analysis, a decision was made to explore some specific rate adjustments to deal with the cost recovery problem, rather than

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<sup>1</sup> BPA initially asked for all written comments by August 24, 2000, but during the August 21, 2000, meeting, BPA extended the time for customers to provide comments while settlement discussions occurred. In her October 6, 2000, letter to customers, the Administrator requested all comments be sent to BPA by October 16, 2000.

proposing modifications to all the contracts. BPA concluded that it could maintain an acceptable TPP level by revising the CRAC contained in the proposed 2002 General Rate Schedule Provisions (GRSPs) and by making some corresponding changes to the Slice methodology.

BPA set aside the following weeks to engage the rate case parties in settlement discussions aimed at resolving the cost recovery problem in a mutually agreeable way. These discussions centered on four major issues presented by the option proposed by BPA:

1. How should the CRAC be redesigned to provide BPA with the necessary financial protection?
2. How should the Slice product be modified to insure that Slice customers pay an equitable share of BPA's augmentation costs?
3. What changes, if any, are necessary to the proposed settlement of the IOUs Residential Exchange benefits, as a consequence of the revision to the CRAC?
4. How would the proposed changes to the CRAC impact customers who had already signed contracts?

65 Fed. Reg. 75272, at 57274 (2000).

BPA notified FERC on September 4, 2000, of its decision to pursue modifications to the CRAC and requested that the stay be extended through April 30, 2001, so that settlement discussions could be continued and a limited section 7(i) proceeding could be conducted. During the month of September, BPA and rate case parties engaged in a series of meetings to discuss ways of resolving the four major issues described above. Despite this effort, the parties were unable to reach a consensus.

On October 6, 2000, BPA notified rate case parties that it intended to initiate a limited section 7(i) proceeding to revise the CRAC; make adjustments to the Slice methodology; adjust the forecasts used in the Residential Exchange Settlements; and address the Subscription contracts signed in the summer of 2000 in order to deal with the issues facing BPA. The Administrator set the close of business on October 16, 2000, as the date after which any *ex parte* communications with BPA would be prohibited.

### **1.3.2 Bonneville Power Administration's 2002 Amended Power Rate Proposal**

Section 7(i) of the Northwest Power Act 16 U.S.C. § 839e(i), requires that BPA's wholesale power rates be established according to certain procedures. These procedures include, among other things, issuance of a FRN 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) (Procedures). The Procedures implement the section 7(i) requirements.

On December 1, 2000, BPA published a FRN of Proposed Amendments to 2002 Wholesale Power Rate Adjustment Proposal, 65 Fed. Reg. 75272 (2000). BPA's 2002 wholesale power rate

proceeding began with a prehearing conference on December 12, 2000. At that prehearing conference, the Hearing Officer issued orders concerning procedural matters in this proceeding. BPA's Amended Proposal, filed on December 18, 2000, was supported by prefiled written testimony and studies sponsored by approximately 25 witnesses. On December 18, 2000, the Hearing Officer issued an order establishing the schedule for the rate proceeding. Oral clarification on BPA's Amended Proposal occurred on December 18 and 19, 2000. The schedule was revised on January 31, 2001, and March 2, 2001, to accommodate settlement discussions between BPA staff and rate case parties. *See* section 1.1.2.1 *infra*.

### **1.3.2.1 The Partial Stipulation and Settlement Agreement**

Considering BPA's *ex parte* rule, on January 9, 2001, BPA issued a notice of a workshop with customers to address a settlement proposal submitted by a group of BPA customers. That noticed settlement workshop took place on January 11, 2001, and was continued to January 19, 2001, and January 23, 2001. Noticed settlement workshops also took place on January 31, 2001, February 2, 2001, February 6, 2001, and February 13, 2001.

On January 31, 2001, BPA filed a request with the Hearing Officer to amend the procedural schedule, given that BPA staff and parties were in the process of noticed settlement discussions. On January 31, 2001, the Hearing Officer granted BPA's request.

As a result of these discussions, a partial stipulation and settlement was reached between BPA staff and the Joint Customer Group, which was comprised of Avista Corporation (Avista), Idaho Power Company (IPC), PacifiCorp, Portland General Electric (PGE), Puget Sound Energy, Inc., Seattle City Light, Market Access Coalition,<sup>2</sup> Northwest Requirements Utilities,<sup>3</sup> Pacific Northwest Generating Cooperative,<sup>4</sup> Public Power Council,<sup>5</sup> Public Generating Pool,<sup>6</sup> Western

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<sup>2</sup> Market Access Coalition Group includes: Benton County Public Utility District (PUD), Franklin County PUD, Grays Harbor PUD, City of Richland Energy Service Department, and Klickitat County PUD.

<sup>3</sup> Northwest Requirements Utilities includes: Benton County PUD, Benton Rural Electric Association, Central Lincoln PUD, Columbia Basin Electric Cooperative, Columbia Power Cooperative, Columbia REA, Columbia River PUD, Ferry County PUD No. 1, City of Forest Grove, Franklin County PUD, Harney Electric Cooperative, Hood River Electric Cooperative, City of Idaho Falls, Inland Power & Light, Klickitat County PUD, McMinnville Water & Light, Midstate Electric Cooperative, Nespelem Valley Electric Cooperative, Northern Wasco County PUD, Orcas Power & Light, Oregon Trail Electric Cooperative, City of Rupert, Skamania County PUD, Surprise Valley Electrification Corp., Tanner Electric Cooperative, United Electric Cooperative, Vera Water & Power, Wasco Electric Cooperative, and Wells Rural Electric

<sup>4</sup> Pacific Northwest Generating Cooperative includes: Blachly-Lane Electric Cooperative, Central Electric Cooperative, Inc., Clearwater Power Company, Consumers Power Inc., Coos-Curry Electric Cooperative, Inc., Douglas Electric Cooperative, Fall River Rural Electric Cooperative, Inc., Lane Electric Cooperative, Inc., Lost River Electric Cooperative, Northern Lights Inc., Okanogan County Electric Cooperative, Inc., Raft River Rural Electric Cooperative, Inc., Salmon River Electric Cooperative, Inc., Umatilla Electric Cooperative, and West Oregon Electric Cooperative, Inc.

<sup>5</sup> Public Power Council includes: City of Albion, Alder Mutual Light Co., Ashland, Bandon, Benton PUD, Benton REA, Big Bend, Blachly-Lane Electric, Blaine City Light, Bonners Ferry, Burley Municipal District, Cascade Locks, Central Electric Cooperative, City of Centrala, Chelan County PUD, Cheney, City of Chewelah, Clallam PUD, Clark Public Utilities, Clatskanie PUD, Clearwater Power, Columbia Basin Electric, Columbia Power, Columbia River PUD, Columbia REA, Consumers Power, Coos-Curry Electric, Town of Coulee Dam Light Department, Cowlitz PUD, City of Declo, Douglas Electric Cooperative, Douglas PUD, Drain Light & Power, East End Mutual, Eatonville, Ellensburg, Elmhurst, Emerald PUD, Eugene Water and Electric Board, Fall River, Farmers Electric Co., Ferry PUD, City of Fircrest, Flathead, Forest Grove, Franklin PUD, Glacier, Grant PUD, Grays Harbor

Public Agencies Group,<sup>7</sup> Idaho Public Utilities Commission, Montana Public Service Commission, Public Utility Commission of Oregon, and Washington Utilities and Transportation Commission. The Partial Stipulation and Settlement Agreement became effective on February 15, 2001.

### **1.3.2.2 Bonneville Power Administration's 2002 Supplemental Power Rate Proposal**

The settlement was incorporated into the BPA staff's Supplemental Proposal. On February 15, 2001, BPA staff filed the Supplemental Proposal. The Supplemental Proposal was supported by prefiled written testimony and a study that were sponsored by approximately 25 witnesses.

On March 2, 2001, BPA again filed a request with the Hearing Officer to amend the procedural schedule to allow parties additional time to file their direct cases. On March 2, 2001, the Hearing Officer granted a time extension setting March 7, 2001 as the date for parties' direct cases. On March 27, 2001, litigants to the proceeding filed testimony in rebuttal to the parties' direct cases. Written discovery of BPA's and the parties' direct and rebuttal cases occurred throughout the hearing. BPA responded to approximately 350 data requests concerning its amended rate proposal and its supplemental proposal.

Cross-examination took place on April 12 and 13, 2001. The parties submitted initial briefs on April 24, 2001. Oral argument before the Administrator was held on May 2, 2001. The Draft Supplemental ROD was issued and distributed to parties on May 25, 2001. On June 5, 2001, parties submitted briefs on exceptions.

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* section 1010.5 of BPA's Procedures. BPA took oral and written comments at a transcribed field hearing conducted on January 22, 2001, in Portland, Oregon. BPA received and considered 690 written comments submitted during the participant comment

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PUD, Harney, Heyburn, Hood River, Idaho County, Idaho Falls, Inland, Kittitas PUD, Klickitat PUD, Kootenai, Lakeview, Lane, Lewis PUD, Lincoln Electric, Lost River, Lower Valley Energy, Mason PUD No. 1, Mason, PUD No. 3, McCleary Light & Power, McMinnville, Midstate Electric, Milton, Milton-Freewater, City of Mindoka, Mission Valley Power, Missoula, Modern Electric Water Co., Monmoth, Nespelem Valley Electric Cooperative, Northern Lights, Northern Wasco PUD, OHOP Mutual Light Co., Okanogan Electric, Okanogan PUD, Orcas Power & Light, Oregon Trail Electric Cooperative, Pacific PUD, Parkland, Pend Oreille PUD, Peninsula Light, City of Plummer, Port Angeles, Raft River, Ravalli, Richland, Riverside, Rupert, Salem Electric, Salmon River, Skamania PUD, Snohomish PUD, City of Soda Springs, South Side Electric, Springfield Utility Board, Town of Steilacoom, Sumas, Surprise Valley Electrification Cooperative, Tacoma Power, Tanner Electric, Tillamook PUD, Umatilla Electric, United Electric, Vera, Vigilante, Wasco Electric, Wells Rural, West Oregon, Wahkiakum PUD, and Whatcom PUD.

<sup>6</sup> The Public Generating Pool includes: Grant County PUD No. 2, Eugene Water & Electric Board, Seattle City Light, Tacoma City Light, Cowlitz County PUD, Chelan County PUD, Douglas County PUD, and Pend Oreille County PUD.

<sup>7</sup> Western Public Agencies Group includes: PUD No. 1 of Snohomish County, Elmhurst Mutual Power and Light Company, Ohop Mutual Light Company, City of Ellensburg, PUD No. 2 of Pacific County, PUD No. 1 of Clark County, PUD No. 1 of Grays Harbor County, Peninsula Light Company, Lakeview Light & Power Company, Parkland Light and Water Company, PUD No. 1 of Clallam County; PUD No. 1 of Lewis County; PUD No. 1 of Mason County, PUD No. 3 of Mason County, City of Cheney, Alder Mutual Light Company, City of Milton, Town of Steilacoom, Town of Eatonville, City of Fircrest, and PUD No. 1 of Kittitas County.



period, which officially ended on February 14, 2001. BPA also received many written comments after the end of the official comment period through the issuance of the Draft Supplemental ROD. Since the issuance of the Draft Supplemental ROD BPA has received thousands of additional public comments. The transcribed field hearing and the comments from these rate case participants are part of the record upon which the Administrator bases his decisions.

### **1.3.3 Scope of the Rate Case**

BPA's Supplemental Proposal deals with cost recovery problems by amending certain risk mitigation tools contained in BPA's GRSPs, which apply to BPA's base rates. BPA views this approach as a reliable and prudent means of assuring cost recovery while maintaining the basic underpinnings of BPA's Subscription Strategy for marketing power in the coming rate period. The additional hearing phase addressed the problems created by increased purchase power costs created due to increased loads resulting from higher prices in a volatile market environment. In this additional hearing proceeding of the 2002 rate case, the Administrator did not open issues previously determined to be outside the scope of the rate case in 1999, as described in the original 1999 FRN<sup>8</sup> and in the May 2000 ROD, WP-02-A-02. BPA's proposal to amend the risk mitigation tools, rather than revise the base rates, does not require that BPA reexamine in this proceeding every issue that was debated and decided in the earlier phase of this proceeding. Many of those issues are not germane to the cost recovery problem that the additional hearing proceeding was initiated to address.

The scope of this additional hearing proceeding is limited only by those guidelines established by the Administrator during the first phase of this 2002 rate proceeding. A summary of the scope is described below, as well as the parameters of the specific problem that is being addressed in this portion of the proceeding.

On August 13, 1999, pursuant to Rules of Procedure 1010.3(f) of BPA's Procedures, the Hearings Officer was directed to exclude from the record any evidence or arguments related to five specific areas. The first area of exclusion concerns the Cost Review recommendations and BPA's planned implementation of those recommendations which received extensive public review. This rate proceeding did not revisit the methodology used to develop the Cost Review recommendations, the policy merits or wisdom of the specific recommendations, or BPA's implementation plans. The second area of exclusion concerns decisions made in the Subscription Strategy. The third area of exclusion concerns decisions made in the context of the Principles. The fourth area of exclusion concerns transmission issues that are not part of the rate case or included in the settlement agreement reached in BPA's transmission rate case. The fifth area of exclusion concerns certain previous adjustments to the PF-96 Rate.<sup>9</sup>

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<sup>8</sup> The details of the elements that were excluded from the earlier proceeding are described in detail at 64 FR 44318-44323 (August 13, 1999).

<sup>9</sup> FERC granted final approval of the Targeted Adjustment Charge for Uncommitted Loads (TACUL) on October 26, 2000, in docket EF00-2013-000. U.S. Dept. of Energy, Bonneville Power Administration, 93 FERC ¶ 62,062 (2000).

### **1.3.4 Waiver of Issues by Failure to Raise in Briefs**

BPA's Rules of Procedure provide that parties whose briefs do not raise and fully develop their positions on any issue shall be deemed to take no position on such issue. In such instances, arguments are deemed to be waived. *See* Rules of Procedure 1010.13(b). During this rate proceeding parties periodically discussed a procedural change making the briefs on exceptions optional. The brief on exceptions is the opportunity to: (1) raise any alleged legal, policy, or evidentiary errors in the draft record of decision; or (2) provide additional support for tentative decisions contained in the draft record of decision. *See* Rules of Procedure 1010.13(d). In this rate proceeding, parties proposed that if a party elected not to file a brief on exceptions that party would not be deemed to have waived any argument so long as it had made the argument in its initial brief. Oral Tr. 170. At oral argument BPA stipulated to an agreement with the parties that "the parties will not be deemed to have waived any argument by their failure to raise such an issue in their briefs on exceptions, as long as the issue has been raised in the initial brief." Oral Tr. 172. The Hearing Officer accepted the stipulation and ordered the stipulation into effect. *Id.*

## **1.4 Legal Guidelines Governing Establishment of Rates**

### **1.4.1 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 FERC. 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. *See* 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. *See* 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. *See* 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 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.

#### **1.4.2 The Broad Ratemaking Discretion Vested in the Administrator**

The Administrator has broad discretion to interpret and implement statutory standards applicable to ratemaking. These standards focus on cost recovery and do not restrict the Administrator to any particular rate design methodology or theory. *See Pacific Power & Light v. Duncan*, 499 F. Supp. 672 (D.C. Or. 1980); *accord City of Santa Clara v. Andrus*, 572 F. 2d 660, 668 (9<sup>th</sup> Circuit 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 Administrator*, 774 F. 2d 1262, 1266 (4<sup>th</sup> Circuit 1985).

The United States Courts 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 (9<sup>th</sup> Circuit 1984) (“[b]ecause BPA helped draft and must administer the Northwest Power Act, we give substantial deference to BPA’s statutory interpretation”); *PacificCorp v. F.E.R.C.*, 795 F. 2d 816, 821 (9<sup>th</sup> Circuit 1986) (“BPA’s interpretation is entitled to great deference and must be upheld unless it is unreasonable”); *Atlantic Richfield Co. v. Bonneville Power Administration*, 818 F. 2d 701, 705 (9<sup>th</sup> Circuit 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 Regional Act is to be given great weight”); *Department of Water and Power of the City of Los Angeles v. Bonneville Power Administration*, 759 F. 2d 684, 690 (9<sup>th</sup> Circuit 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”).

#### **1.5 Federal Energy Regulatory Commission 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 Administration*, 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 Administration*, 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).

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 Administration*, 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 are subject to FERC jurisdiction. *Central Lincoln Peoples' Utility District v. Johnson*, 735 F. 2d 1101, 1115 (9<sup>th</sup> Circuit 1984).

## **1.6 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 (9<sup>th</sup> Circuit 1990). See also *Southern California Edison Co. v. Jura*, 909 F. 2d 339, 342 (9<sup>th</sup> Circuit 1990); and *Central Lincoln Peoples' Utility District, et al., v. Johnson*, 735 F. 2d 1101, 1115 (9<sup>th</sup> Circuit 1984).

## 2.0 OVERALL POLICY CONTEXT

### 2.1 The Cost Recovery Problem

This proceeding is a continuation of the WP-02 Rate Proceeding. This part of the proceeding is being conducted for the discrete purpose of resolving a cost recovery problem brought about by market price trends and load placement changes occurring since the record was closed in May 2000. Burns and Berwager, WP-02-E-BPA-62, at 3.

#### 2.1.1 The Amended Proposal

In the Federal Register Notice (FRN) of December 1, 2000, BPA proposed amendments to its May Proposal. 65 Fed. Reg. 75272 (2000). BPA explained that its proposed amendments were necessary because market prices were expected to be much higher and more volatile than assumed in the May Proposal. *Id.* at 75273. As a result of high market prices, BPA now expected much greater demand for service from customers, demand that BPA is required to serve and that exceeds the generating capability of the Federal Columbia River Power System (FCRPS). *Id.* To meet this increased load obligation, BPA would need to make substantially greater power purchases in the market at substantially higher and more uncertain prices than anticipated in revenue requirements for the 2002 rate proposal. *Id.* at 75274. Therefore, an adjustment to BPA's May Proposal was necessary to ensure rates and revenue will be sufficient to recover the costs with a high degree of certainty. *Id.* BPA's proposed amendments dealt with this cost recovery problem by amending certain risk mitigation tools contained in the 2002 General Rate Schedule Provisions (GRSPs), which apply to the base rates. *Id.* BPA views this approach as a reliable and prudent means of assuring cost recovery while maintaining the basic underpinnings of BPA's Subscription Strategy for marketing power in the coming rate period. *Id.*

On December 12, 2000, BPA filed its 2002 Amended Power Rate Proposal (Amended Proposal). The Amended Proposal was designed to deal with the evolving cost recovery problems BPA faced at that time. However, after filing its Amended Proposal, BPA observed an even more dramatic change in the market. Burns and Berwager, WP-02-E-BPA-70, at 2-4. The impact on BPA was twofold. BPA's reserves were being depleted well below what was forecasted in the Amended Proposal and the forecasted price for augmentation purchases continued to climb. *Id.* About that time, BPA was notified that a group of customers that included a large portion of BPA's publicly-owned utilities, and the IOUs, as well as the state commissions, wanted to discuss the continued viability of the Amended Proposal and an alternative proposal that they had developed. *Id.* BPA noted in the Amended Proposal that it would update the final studies for changes in BPA's reserve levels and costs to purchase augmentation power as was typically done in rate proceedings. However, it was apparent that the adjustments in the final studies would be very significant and would have a dramatic impact on the final rates. In order to afford parties the opportunity to comment and test these changes in the rate proceeding, BPA agreed to file a new proposal that would reflect the changes to reserve levels and increased market prices. BPA also agreed to continue discussions with a group of customers regarding their alternative proposal and, if an agreement was reached, to file a new proposal consistent with this agreement.

### 2.1.2 The Supplemental Proposal

On February 15, 2001, BPA filed its 2002 Supplemental Power Rate Proposal (Supplemental Proposal). There are three reasons why BPA filed the Supplemental Proposal. First, BPA's forecast for starting rate period reserves had dropped substantially since the forecast in BPA's Amended Proposal. Burns and Berwager, WP-02-E-BPA-70, at 2. Second, market prices available now for power during the first two years of the rate period are significantly higher than BPA had forecast in the Amended Proposal. *Id.* The third reason is that, as a result of discussions with the rate case parties, BPA staff had reached a Partial Stipulation and Settlement Agreement with many of those parties. *Id.*

**Starting Reserves:** Since December, forecasts for run-off for this water year have also declined substantially. *Id.* Water Year forecasts in BPA's May Proposal and BPA's Amended Proposal assumed average water for both this Fiscal Year (FY) 2001 and for the next five years of the rate period—102.4 million acre feet (MAF). *Id.* By contrast, FY 2001 could be one of the lowest runoff years on record, with current runoff forecasts now at 55-57 MAF. These conditions required BPA to purchase much more power in FY 2001 than expected to meet loads, at extremely high prices, and have reduced the amount of surplus energy BPA can sell this year. *Id.* at 3. As BPA described in its Supplemental Proposal, prices in the wholesale electricity market have been extremely volatile and high. In fact, during one week in January alone, BPA purchased over \$50 million in power to meet load. *Id.* This put tremendous pressure on BPA's end-of-year reserves. *Id.* End-of-year reserves translate into starting rate period reserves. *Id.* In BPA's May Proposal, starting reserves were estimated to be \$842 million on an expected value basis. *Id.* In BPA's Amended Proposal, the estimate for starting reserves had increased to \$929 million. *Id.* However, by the time of the Supplemental Proposal, the expected value of BPA's starting reserves had dropped to \$309 million. *Id.* There is still a significant range of uncertainty surrounding this estimation of starting reserves. *Id.* This is driven by some unknown factors for the rest of this fiscal year around hydro operations related to fish requirements, run-off levels, and the volatility in market prices. *Id.* BPA has updated the starting reserve level in the final studies based upon the results of the second quarter review. Final Study, WP-02-FS-BPA-09.

**Market Prices:** A significant drop in starting reserve levels, without other adjustments, reduces Treasury Payment Probability (TPP) for the five-year rate period. *Id.* Starting reserves are a key risk mitigation tool in this rate proposal. Lefler, *et al.*, WP-02-E-BPA-73. Therefore, in order to offset this decline, and maintain a TPP level within the acceptable range, adjustments to other tools were needed. Burns and Berwager, WP-02-E-BPA-70, at 3.

Besides the increase in market prices over the past year, BPA has identified another important change in market prices. Market prices during the rate period are forecast to be higher in the first years of the rate period, ranging from \$200/megawatthour (MWh) to \$240/MWh for FY 2002, and then drop during the last years of the rate period, to a range between \$40/MWh and \$60/MWh in FY 2006. *Id.* at 4. This is significantly different from the risk-adjusted expected price forecast used in the Amended Proposal for the five-year rate period of around \$48/MWh. In the Amended Proposal expected prices for individual years did not vary by more than \$5/MWh from the \$48/MWh average. *Id.*

Because BPA will be in the market purchasing power to serve load during the next five years, BPA's purchase power costs will fluctuate as market prices change. *Id.* Because the potential levels of power purchases and prices are so great, BPA needs to concern itself not only with annual or rate period totals, but with the seasonal and semi-annual timing of costs and revenues. *Id.* In order to maintain TPP at an allowable level, all other things being equal, the expected value for the average rate over the five years will be higher with an average flat rate than with a rate shaped to match the expected market. *Id.* Therefore, BPA has revised the Load-Based (LB) Cost Recovery Adjustment Clause (CRAC), from the Amended Proposal, so that expected revenues more closely match the shape of augmentation costs. *Id.*

BPA staff participated in noticed settlement talks with rate case parties. In these discussions BPA explained the changes to starting reserves and market price escalation and uncertainty that have occurred since the Amended Proposal and that must be addressed in this supplemental rate case. *Id.* BPA and a large group of the parties were able to reach agreement on how BPA should address these problems. *Id.* The Partial Stipulation and Settlement Agreement embodied concepts that are different from what is contained in BPA's Amended Proposal. *Id.* The Supplemental Proposal represents a package that meets BPA's critical objectives as specified in the Amended Proposal and resolves most of the issues that rate case parties had with BPA's earlier proposal. *Id.* at 5.

The Partial Stipulation and Settlement Agreement is intended to serve as a basic understanding for an acceptable approach to resolving the cost recovery problem faced by BPA. *Id.* The Supplemental Proposal is intended to serve as a means of implementing the objectives and intent outlined in the Partial Stipulation and Settlement Agreement. *Id.* In the testimony of Lefler, *et al.*, WP-02-BPA-E-73, BPA staff describe how they embodied the intent of the Partial Stipulation and Settlement Agreement.

## **2.2 Policy Response to the Cost Recovery Problem**

From the outset, and in response to the cost recovery problem, the BPA Administrator developed the criteria BPA would use to determine the appropriate approach to solving this cost-recovery problem. *See* Burns and Berwager, WP-02-E-BPA-70, at 6. The criteria for the proposed solution were:

- It should be as simple as possible;
- It should allow Subscription contract signing to proceed to completion as soon as possible;
- It should not require review or revision of the overall Subscription Strategy;
- Specifically, reallocation of Subscription power among customer groups, or a change in the basic balance of interests in Subscription should not be required;
- It should require limited revisions, if any, to the 2002 rate proposal currently before FERC, and limited revisions, if any, to the Subscription contract; and
- It must achieve the goal of leaving BPA's probability of repaying the U.S. Treasury, in full and on time, within an acceptable range over the 2002-2006 rate period.

In the December testimony supporting the Amended Proposal, BPA staff described the development of the policy objectives. *See* Burns and Berwager, WP-02-E-BPA-62, at 4. The

policy guidance given to BPA staff redesigning the CRAC for the Amended Proposal contained five key components. First, the CRAC, when combined with the other risk mitigation tools modeled, should achieve a TPP that falls within the 80 to 88 percent range established by the Fish and Wildlife Funding Principles (Principles), specifically Principle No. 3. Burns and Berwager, WP-02-E-BPA-70, at 6. Second, redesign of the CRAC should satisfy Principle No. 4. *Id.* Third, given that revenue requirements are not being revised, the CRAC, along with commensurate changes in Slice, must remedy the under-recovery that results from the likelihood of purchasing more power at higher prices than assumed in the May Proposal. *Id.* at 7. Fourth, all other things being equal, BPA would prefer to utilize contingent measures to mitigate revenue and cost uncertainties because the expected value cost to ratepayers is lower. *Id.* However, this must be balanced with tools that will avoid rate shocks resulting from frequent and significant changes to rates, potential customer problems of liquidity, and other implementation risks not captured in the risk analysis. *Id.* And finally, BPA sought to minimize the potential for contention and administrative burden during implementation of the CRAC. *Id.*

The guidance has been refined based on the nature of the Partial Stipulation and Settlement Agreement. *Id.* BPA would still like to avoid frequent and significant change to rates, potential problems of liquidity by customers and other implementation risks. *Id.* However, as a result of discussions with rate case parties leading to the Partial Settlement, BPA and the parties agreed to a revision to the LB CRAC, which would create biannual rate level changes to deal with these augmentation costs. *Id.* As a result of this, BPA will rely less on contingent measures. *Id.* BPA believes that by having a LB CRAC which more closely matches its revenues to its augmentation costs, BPA's proposal will still result in a rate design that results in the overall lowest expected value cost to ratepayers, while achieving BPA's stated TPP objectives. *Id.*

BPA's goal continues to be an 88 percent probability that payments to Treasury be made on time and in full over the five-year rate period. Burns and Berwager, WP-02-E-BPA-70, at 7. As in the May and Amended Proposals, the Supplemental Proposal continues to implement the Principles in order to deal prudently with potential fish mitigation costs. *Id.* at 8. The TPP in the Amended Proposal was 83.4 percent TPP. *Id.* The range of TPPs for this Supplemental Proposal is from 82.7 percent to 85.9 percent, assuming that BPA's total Slice sales are 1,600 average megawatts (aMW). *See* Lefler, *et al.*, WP-02-E-BPA-73.

The Supplemental Proposal is described through the use of a set of analyses instead of a single analysis because of the design of the LB CRAC. Burns and Berwager, WP-02-E-BPA-70, at 8. The LB CRAC in the Supplemental Proposal is a formula, rather than a percentage to be fixed in this Final Supplemental Record of Decision (ROD). *Id.* The formula is based on BPA's net cost of augmentation, which depends on the remaining augmentation need (*i.e.*, the augmentation need for which BPA does not yet have purchases in place), and a market-based forward indicator of future power prices. *Id.* As noted previously, in today's electricity world, future power prices can be highly volatile. *Id.* In addition, the LB CRAC percentage may be large enough to induce some customers to reduce their BPA load. *Id.* To avoid basing another proposal on a single estimate of forward prices and remaining augmentation, BPA is presenting a proposal developed with its customers in which the LB CRAC will adjust to market prices and BPA's augmentation needs. *Id.* Since BPA cannot predict what the forward prices and remaining augmentation needs will be, it is presenting a range of possibilities.



Even with a TPP lower than 88 percent, the proposal still meets the Principles. *Id.* The range of TPPs in the Supplemental Proposal falls within the 80 to 88 percent range allowed by Principle No. 3. *Id.* The LB CRAC fluctuates as actual augmentation costs change, thereby mitigating that market risk. *Id.* And as with the Amended Proposal, this Supplemental Proposal still includes the Safety-Net (SN) CRAC, which serves as additional assurance that payments to Treasury will be made, though it is not modeled in the TPP analysis. *Id.*

### **2.3 How the May Proposal and the Supplemental Proposal Demonstrate Cost Recovery**

The May Proposal demonstrated the adequacy of revenues from the proposed wholesale power rates to recover the rate period costs, including recovery of the federal investment in the FCRPS. The Revised Revenue Test made the demonstration for recovery of the rate period generation revenue requirements, including the cash requirements for risk mitigation that produced an 88 percent probability of making generation function payments to the U.S. Treasury in full in each year of the five-year rate period (*see* WP-02-FS-BPA-02, at 43-44 and 51-52). In addition, the full recovery of generation costs over the 50-year repayment period of the power system was also demonstrated (*Id.* at 44 and 53-54).

The May Proposal included a more robust risk mitigation package than that in prior rate proposals. *See* May Final Proposal Revenue Requirement Study, WP-02-FS-BPA-02, at 2.2. The risk analysis included a new model, the Non-Operations Risk Model (NORM). NORM is used to reflect the probabilistic distributions of cost variations from those included in the revenue requirement. *See* May Final Proposal Risk Analysis Study, WP-02-FS-BPA-03, at 19-23. The RiskMod model, which is used to analyze the operations risks, replaces the STREAM model used in prior rate cases. *Id.* at 4-5.

Risks surrounding costs and hydro operations related to fish and wildlife protection and recovery were prominent in the May Proposal. The Proposal implemented the Principles, *see* Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A, at 335, which were developed regionally to “establish a reasonable range of fish costs to be used for rate setting purposes, given the fact that decisions will not be made as to an actual alternative until after this rate proceeding.” DeWolf, *et al.*, WP-02-E-BPA-39, at 29. Both the NORM and RiskMod models reflect a wide range of potential costs, which reflect costs that may be incurred as decisions are made on fish recovery actions.

In addition to having a more robust risk analysis than in previous rate cases, the May Proposal included robust risk mitigation tools (*see* May Final Proposal Revenue Requirement Study, WP-02-FS-BPA-02, 2.2 ) including starting reserves, 4(h)(10)(C)/FCCF credits, PNR, and a CRAC that would allow BPA to raise rates temporarily if end-of-year accumulated net revenues fall below a pre-determined threshold. These tools resulted in an 88 percent TPP.

By August 2000, however, it was clear that extraordinary changes were occurring in the wholesale electricity market, which threatened to overwhelm the cost recovery capability of the May Proposal. The Supplemental Proposal has been designed to recover the incremental costs and to mitigate the incremental risks brought about by the upheaval in the west coast electricity

market, while leaving intact the May Proposal and its ability to recover the costs BPA was facing at the time the May Proposal was developed.

BPA addressed this cost recovery problem by amending certain risk mitigation tools contained in the 2002 GRSPs, which apply to the base rates. BPA views this approach as a reliable and prudent means of assuring cost recovery while maintaining the basic underpinnings of BPA's Subscription Strategy for marketing power in the coming rate period. The primary cost structure and the rates developed to recover those costs remain unchanged. BPA has not modified the program levels, expense or capital, upon which revenue requirements were based in the May Proposal, nor rerun repayment studies to recalculate the federal interest and amortization components of revenue requirements, nor modified the cash requirements included in revenue requirements for the primary risk mitigation. Because the primary change in BPA's ability to recover costs was the combination of an unanticipated increase in loads with higher and more uncertain market prices, to best enhance cost recovery, the Supplemental Proposal has modified the CRAC to address these specific circumstances. The Supplemental Proposal replaces the single CRAC with a three-component CRAC.

**Load-Based (LB) CRAC:** Certain incremental costs arise from increased load and higher market prices. That increment will be recovered through the LB CRAC. There are two parts of this calculation – the increased costs for augmentation power that were anticipated in the May Proposal, and the total net costs for the augmentation power that were not anticipated in the May Proposal. In the May Proposal, BPA anticipated that the loads it would serve in the FY 2002 to 2006 rate period would exceed its resource capability by about 1,745 aMW. The May Proposal rates provided for sufficient revenue to recover costs if this augmentation power could be purchased for an average cost no higher than \$28.10 per MWh. By August 2000, BPA had acquired about half of this power at an average cost very close to \$28.10. However, forecasts of the costs of purchasing the remaining half increased with the rise in forecasted market prices. The difference in costs to acquire this remaining half, due to the increased market prices, is one of the costs that the LB CRAC will recover.

The second part of the incremental cost is the net cost of serving load that was not anticipated in the May Proposal. The net costs of serving this unanticipated load increase are calculated by estimating the gross costs of obtaining the power and deducting the revenue received from serving the load. As noted in the May Proposal, BPA projected the need to purchase 1,745 aMW to meet its forecasted load obligations. This additional load obligation requires an increase in resources of an additional 1,560 aMW after allowing for 2.8 percent transmission losses. The amount of augmentation may ultimately be reduced by buying down some loads (in which case the costs of the buy-downs will be collected through the LB CRAC) or because of BPA's updating of the load forecast.

A final impact of higher prices is to increase the average cost of spot market purchases and to increase the revenue from spot market sales. After factoring out the augmentation purchase needs described above, BPA's expected spot sales volume exceeds the expected spot purchase volume, so an increase in the market price forecast also increases expected net revenue from spot market sales.

**Financial-Based (FB) CRAC:** The May Proposal included a single CRAC which is essentially the same as the FB CRAC in the Supplemental Proposal. The differences between the two serve to make the current FB CRAC more powerful than the May Proposal's CRAC:

1. The amount that can be collected in the first year, FY 2002, under the FB CRAC is not capped, whereas the amount the May Proposal's CRAC could collect was capped at \$125 million. Lefler, *et al.*, WP-02-E-BPA-73, at 30-31.
2. The FB CRAC for each fiscal year has been designed to begin (if triggered) on the first day of the fiscal year and operate for all 12 months of that year, whereas the May Proposal's CRAC was designed to begin halfway through the fiscal year and operate for the last six months of that year and the first six months of the next. The FB CRAC is stronger because it takes effect six months earlier, providing faster response to financial strain, and because the entire amount in the last year is collected (since the rates for FY 2002 to 2006 cannot apply to FY 2007, the second half of the May Proposal's CRAC revenue in the last year would not be collected). *Id.* at 31.

**Safety-Net (SN) CRAC:** The SN CRAC is a significant feature in the Supplemental Proposal that was not part of the May Proposal. It increases the security of BPA's planned payments to the Treasury by providing a means to substantially bolster the revenue collection of the FB CRAC if BPA misses or forecasts missing a payment to Treasury or any other creditor. The strengthening of the FB CRAC and the addition of the SN CRAC give BPA greater ability to respond to fluctuations in market prices. Conger, *et al.*, WP-02-E-BPA-71, at 7. (BPA has not modeled the impact of the SN CRAC, because many of the details of its implementation will be elaborated through the expedited 7(i) process to be initiated upon the triggering of the SN CRAC, and those details will depend on the particular circumstances that resulted in the triggering.) *Id.* at 34-35.

**Slice:** The May Proposal assumed no Slice load, and argued that BPA's cost recovery would still be sufficient if there were Slice load. Now that contracts for the purchase of the Slice product have been executed, BPA knows the amount of Slice load it will be serving. The Supplemental Proposal assumes the actual amount of Slice load. This allows BPA to make a more direct demonstration of cost recovery. Supplemental Study, WP-02-E-BPA-67, at 2-19 to 2-21.

These changes have provided a TPP in the range of 81.6 to 88.3 percent, depending on what is assumed for the amount of augmentation purchases and market price. *See* Supplemental Final Study, WP-02-FS-BPA-09, at 5.3 to 5.8. Taken together, BPA's May and Supplemental proposals fully demonstrate cost recovery because:

- The base rates recover BPA's revenue requirement, not including the increased level of augmentation and the market prices associated with purchasing to serve unanticipated load.
- The LB CRAC and Slice true-ups recover the costs of the increased level of augmentation at any market price.

- The FB CRAC has been strengthened in the first year, allowing BPA to build reserves in the first year if the starting accumulated net revenues for the rate period are low. Modeling the LB and FB CRACs results in a TPP in the 80-88 percent range that BPA is targeting.
- Additionally, the SN CRAC has been added, and while not modeled in the TPP calculation, it assures that BPA will make its payments to Treasury.

## 2.4 **Legality of Sales to Direct Service Industrial Customers**

### **Issue**

*Whether BPA's power sales to the DSIs are consistent with public preference and the Northwest Power Act's rate directives.*

### **Parties' Positions**

The Public Generating Pool (PGP) and Pacific Northwest Generating Cooperative (PNGC) contend that the Administrator acknowledged in the May ROD that BPA no longer had a legal obligation to sell power to the DSIs. PGP/PNGC Brief, WP-02-B-PG/PN-01, at 3-4. By the time BPA signed Subscription contracts with the DSIs, PGP/PNGC argue, BPA knew that it did not have sufficient resources from the Federal Base System (FBS) to serve its forecasted loads. *Id.* at 4. They also believe that BPA assured its public utility customers that service to the DSIs would not impact their rates. *Id.* Given the lack of surplus firm power, BPA must purchase power on the open market to serve the DSIs. *Id.* Therefore, according to PGP and PNGC, given BPA's need to make market purchases to serve the DSI load, BPA cannot enter into contracts for power sales to the DSIs that include anything but power sold at market-based rates. *Id.* at 5. PGP and PNGC argue that to do otherwise violates the Northwest Power Act and the principles of preference and priority in the sale of federal power to public bodies and cooperatives. *Id.*; PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01.

### **BPA Staff Position**

The Administrator is authorized under section 5(d) of the Northwest Power Act to make discretionary sales to the DSIs. BPA's sales to the DSIs are consistent with public preference and the Northwest Power Act's ratemaking directives.

### **Evaluation of Positions**

The crux of the PGP/PNGC argument appears to be that public preference creates a preference to price in addition to supply. In particular, PGP/PNGC contend that public preference entitles public utilities and cooperatives to all federal power allocated to the FBS, and only after their needs are exhausted can BPA market FBS power to non-preference customers, such as the DSIs. *Id.* at 6. This argument, however, is completely fabricated. The following evaluation addresses the statutory distinctions between preference and priority to the supply of federal power and the pricing of such power under BPA's rate directives.

PGP/PNGC cite statutory authority for the proposition that BPA must sell power in compliance with public preference. *Id.* BPA agrees. However, the arguments asserted by PGP/PNGC would expand public preference far beyond the bounds contemplated by Congress or the courts.

The genesis of public preference is section 4 of the Bonneville Project Act. Section 4(a) states that, “in disposing of electric energy generated at aid project, give preference and priority to public bodies and cooperatives.” 16 U.S.C. § 832c(a). Section 4(b) states that in the event there are “conflicting or competing applications for an allocation of electric energy between any public body or cooperative on the one hand and a private agency of any character on the other, the application of such public body or cooperative shall be granted.” 16 U.S.C. § 832c(b).

As a result, the U.S. Supreme Court, in interpreting this provision, has found that “the preference system merely determines the priority of different customers when the Administrator receives conflicting or competing applications for power that the Administrator is authorized to allocate administratively.” *Aluminum Company of America, et al. v. Central Lincoln Peoples’ Utility District, et al.*, 467 U.S. 380, at 393. Other courts are in accord. *See e.g., Puget Sound Power & Light v. United States*, 23 Cl. Ct. 46, 63 (1991) (a statutory right to preference and priority merely determines who has the first opportunity to purchase federal power which is available and not previously allocated by contract); *City of Santa Clara v. Andrus*, 572 F. 2d 660, 667 (9<sup>th</sup> Cir., 1978) (“the preference clause requires only that public entities be given a preference over private entities in the marketing of power generated by federal reclamation projects.”).

In the instant case, there are no competing applications for power between preference and non-preference entities. BPA properly offered to sell federal power to its public body and cooperative customers up to their full regional firm load requirements, and such customers entered into power sales contracts purchasing as much power as they were legally entitled to. Knowing that BPA could on a planning basis obtain power or generate power sufficient to meet its planned loads and that its preference customers’ needs for power were satisfied, BPA also offered power sales contracts to BPA’s IOU and DSI customers. BPA did not make power sales to non-preference customers for which there was an existing demand by a preference customer. BPA’s power sales to the DSIs and other non-preference customers therefore satisfy statutory preference and priority rights.

Public preference provides preference customers a priority to federal power, but does not provide these customers a right to any particular block of federal power or to the least expensive federal power. Indeed, Congress preserved public preference for “[a]ll power sales” under the Northwest Power Act in section 5(a), but directed the pricing of these sales under the section 7 rate directives. 16 U.S.C. § 839c(a). The federal courts have consistently failed to find that a preference to power supply extends to price. For instance, in *Central Lincoln People’s Utility District et al. v. Johnson*, 735 F. 2d 1101, 1125 (9<sup>th</sup> Cir. 1984) (*Central Lincoln*), the United States Court of Appeals for the Ninth Circuit rejected an argument that “preference entitles its members to purchase not just available power, but the cheapest available power.” The court concluded that the Northwest Power Act “couches the preference in terms of ‘power sales,’ not price.” *Id.* The court found that, at most, petitioners therein had a right to purchase power at a “reasonable price,” based on section 7 of the Northwest Power Act. *Id.*

Similarly, in *Trinity County Public Utility District v. Harrington*, 781 F. 2d 163, 166 (9<sup>th</sup> Cir. 1986), the Ninth Circuit expressly rejected arguments that public preference entitled preference entities to a particular block of federal power or any expansion of preference rights that would result in “a preferential rate in addition to a preferential power allocation.” As such, there are no cases cited by PGP/PNGC, and none BPA is aware of, supporting the argument that there is a preference to price.

In their initial brief, PGP and PNGC argued that the Administrator’s proposal for service to the DSIs is inconsistent with commitments previously made to other customer groups and violates section 9(i)(1)(A) of the Northwest Power Act. PGP/PNGC Brief, WP-02-B-PG/PN-01, at 3-4. In their brief on exceptions, PGP/PNGC charge that BPA’s proposal for service to the DSIs ignores controlling law by advocating “an unlawful allocation of FBS resources and a rate case outcome driven by political imperatives.” PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01, at 4. PGP/PNGC’s brief on exceptions goes on to state many legal arguments that were not raised in their initial brief. As discussed above, there is no basis upon which to conclude that an application by a preference customer for requirements service has been denied, or that any competing applications were improperly granted. Similarly, BPA has complied with all statutory requirements. Only if BPA were to declare an “insufficiency” in obtaining federal resources, would BPA be unable to serve both preference and non-preference customers. Only under these circumstances would BPA be forced to allocate federal power amongst its preference customers. 16 U.S.C. §§ 839c(b)(5) and (6). BPA made no such declaration, and section 9(i)(1)(A) on replacing interrupted DSI service does not apply.

It should be noted, however, that BPA does not determine the lawfulness of its power sales contracts in BPA’s rate cases. BPA’s power sales contracts are developed through negotiations and then offered to BPA’s customers. For ratemaking purposes, BPA properly assumes that its existing contracts are valid. The determination of whether such contracts are lawful, while first made by BPA before offering the contracts, is ultimately decided by the federal courts and, in any event, is not made in a BPA rate case.

As an extension of their broader preference arguments, PGP/PNGC argue that BPA cannot avoid complying with public preference and priority requirements by asserting that any contract is binding in accordance with its terms. *Id.* at 7-9. In fact, however, BPA has not claimed that the fact that BPA’s contracts are “binding in accordance with their terms” somehow repeals statutory public preference provisions. In the instant case, BPA’s power sales to the DSIs are lawful and consistent with public preference. In addition, such contracts are binding in accordance with their terms. In support of their argument, PGP/PNGC quote a Supreme Court opinion stating:

IOUs and DSIs are ‘nonpreference’ customers, and BPA is allowed to contract to sell them only power for which preference customers do not apply. Once a contract between BPA and a customer is signed, however, the Project Act makes clear that the contract is ‘binding in accordance with the terms thereof.’

*Aluminum Co. of America v. Central Lincoln Peoples’ Util. Dist., et al.*, 467 U.S. 380, at 384.

Contrary to supporting PGP/PNGC's case, the quotation confirms that BPA has acted in accordance with the law. As noted above, BPA fully complied with public preference. PGP/PNGC further argue that BPA's current definition of the FBS and the allocation of resource pools within the FBS are unlawful because they force preference customers to share in the cost of providing the DSIs with a melded rate for power at a time when BPA expects to buy power on the market for service to DSI load. PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01, at 9-10. PGP/PNGC argue that the FBS may not be defined in a manner that includes purchases to serve DSI load. *Id.* Instead, according to PGP/PNGC, the DSI customer class is entitled to share in the lowest cost federal resources only if there is no competing application from a preference customer for power generated by those resources. PGP/PNGC's arguments in support of these contentions, however, continue to confuse preference to supply with preference to price. PGP/PNGC note that if there are competing applications for power by a preference customer and a private agency of any type, the application of the preference customer shall be granted. PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01, at 8-9. PGP/PNGC then make a huge jump in their legal theory. They argue that if there are competing applications for *FBS power*, then the preference customer's application must be granted.

While PGP/PNGC argue that the DSIs had requests for allocations of FBS resources, this is not true. The DSIs simply had requests for federal power. The FBS is a statutory term used for BPA's ratemaking under section 7 of the Northwest Power Act. While the Act has provisions governing the manner in which BPA may sell federal power, its only provisions addressing how BPA should actually sell *FBS power* are for an insufficiency condition, that is, when BPA is unable to obtain power or resources sufficient to meet its planned load. Instead, sections 7(b), 7(c), and 7(f) of the Act describe how the costs of BPA's resources are allocated *for the purpose of establishing rates*. 16 U.S.C. §§ 832e(b), (c), and (d). Similarly, BPA did not note, as PGP/PNGC assert, that "the applications for FBS allocations submitted to it by August 2000 exceeded its resources by [a] margin greater than the sum of all DSI applications for allocations," because BPA does not receive applications for allocations of *FBS resources*. See PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01, at 10. BPA simply markets federal power.

With respect to PGP/PNGC's arguments regarding the propriety of the allocation of resources to the FBS, and then to customer classes, it should be noted that the Administrator addressed that issue thoroughly in the May ROD. See May ROD, WP-02-A-02, section 12.3. It may be helpful in this context, however, to reiterate a few key points to show that the FBS is a single resource pool, not a segmented resource to be divided into separately priced portions that serve any particular customer class. First, the Northwest Power Act 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 the 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). The Northwest Power Act expressly recognizes that the Administrator may acquire resources as needed to replace the reduced capability of the FBS.

In addition, the Northwest Power Act does not limit resource acquisitions to the amounts needed to meet only preference customer loads. Section 6(a)(2) of the Northwest Power Act provides that “[i]n 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). This provision does not limit BPA’s acquisition of resources only to its preference customer obligations.

As noted in BPA’s testimony related to the FBS, “BPA does not assume that costs of individual [FBS] resources will be allocated to particular individual power sales.” Doubleday, *et al.*, WP-02-E-BPA-44, at 7. The Northwest Power Act’s rate directives do not allocate the FBS resources solely to BPA’s preference customers. For example, 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 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 all its customers.

PGP/PNGC argue that BPA cannot justify its plan to purchase power in the wholesale market, sell the power far below cost to the DSIs, and charge the unrecovered costs of this subsidy to preference customers by calling such purchases FBS replacements or service to contracted load. PGP/PNGC Ex. Brief, WP-02- R-PG/PN-01, at 11-18. PGP/PNGC argue that BPA claims authority to forecast loads and contractual obligations for the post-2001 period not only for its preference customers but also for customers for whom BPA has no legal obligation to provide service. *Id.* For responses to many of the points contained in this argument, BPA refers to Chapter 12 of BPA’s May ROD, WP-02-A-02. This broad allegation, however, will also be addressed by reviewing its component parts.

PGP/PNGC argue that if BPA’s interpretation were accepted, BPA could enter into an agreement to sell power to a California IOU and then set rates forcing preference customers to subsidize power purchases needed to serve the load. PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01, at 11-18. This argument is not persuasive. BPA is only statutorily permitted to sell firm requirements power to regional utilities. BPA also has statutory authority to sell firm power to BPA’s regional DSI customers. In contrast, any sales outside of the region must be surplus power sales and satisfy the Regional Preference Act. 16 U.S.C. § 837. Similarly, BPA does not acquire power in order to serve the firm power loads of extraregional utilities in the manner that BPA acquires power to serve regional firm loads. *See* 16 U.S.C. § 839d.

PGP/PNGC argue that the Northwest Power Act does not provide BPA authority to extend unilaterally the expired statutory allocation of a portion of the FBS to DSI customers at the expense of preference customers. PGP/PNGC Ex. Brief, WP-02- R-PG/PN-01, at 12. This argument is difficult to understand. There are no “allocations” of actual power to BPA’s customers, particularly FBS power. BPA has acquisition authority which “by providing the



Administrator with the ability to expand the energy resource pool available to him, allows the Administrator to enter into long term power sale contracts with preference and investor-owned utilities, federal agencies and existing direct-service industrial customers and obviates the need for him to administratively allocate the limited amount of federal resources among existing and potential claimants.” H.R. Rep. No. 96-967, Pt. II, 96<sup>th</sup> Cong., 2<sup>nd</sup> Sess. 35 (1980). BPA determines the requirements needs of BPA’s utility customers and the amount of power to be sold to the DSIs and then ensures that BPA has sufficient power to meet its firm contractual obligations. Thus, BPA is not unilaterally extending an expired allocation of FBS power to any customer.

PGP/PNGC argue that BPA cannot forecast future discretionary obligations in order to justify power purchases to create the surplus needed to serve loads and charge costs of them to preference customers, which would stand preference and priority to the least expensive power on its head. PGP/PNGC Ex. Brief, WP-02- R-PG/PN-01, at 13. Again, however, PGP/PNGC ignore the Administrator’s authority to sell power to the DSIs after 2001. Section 5(d)(1)(B) of the Act required the Administrator to offer each existing DSI “an initial long term contract that provides such customer an amount of power equivalent to that to which such customer [was] entitled under its contract dated January or April 1975.” 16 U.S.C. § 839c(d)(1)(B). Additionally, contrary to PGP/PNGC’s argument, the price of power is not determined by preference, but rather by the section 7 rate directives. *See* 16 U.S.C. § 839c(a).

In spite of the fact that those initial DSI contracts have either been terminated or will terminate in the near future, the Administrator still retains explicit authority to make discretionary sales to the DSIs after 2001. Section 5(d)(1)(A) provides that “[t]he Administrator is authorized to sell in accordance with this subsection electric power to existing direct service industrial customers.” 16 U.S.C. § 839c(d)(1)(A). The legislative history of the Northwest Power Act is plainly in accord with the Administrator’s position that the current proposal for DSI service is legally appropriate even though it is not required:

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 are authorized but not mandated.*

H.R. Rep. No. 96-976, Pt. I, 96<sup>th</sup> Cong., 2d Sess. 61 (1980) (emphasis added). Perhaps more importantly, the Act requires that rates for Industrial Firm Power (IP) to serve DSI load under power sales contracts must be established consistent with section 7(c) of the Act, which provides:

The rate or rates applicable to direct service industrial customers shall be established . . . for the period beginning July 1, 1985, 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). This formulation is basically the Priority Firm (PF) rate plus an industrial margin, except that the rate for DSI service cannot be any lower than the rates “in effect for the contract year ending on June 30, 1985” (*i.e.*, the so-called “floor rate”). *Id.* These are the rate parameters currently proposed for DSI service. As noted in the May ROD:

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 . . . . 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 . . . .

May ROD, WP-02-A-02, at 15-70. Thus, BPA’s proposal for DSI service is consistent with applicable rate directives of the Northwest Power Act. The DSI rate for Industrial Firm Power service must either be directly linked to the currently proposed PF rate (plus the applicable industrial margin) or default to the level of IP rates in effect in 1985 (*i.e.*, the floor rate) if the floor rate is higher. Because the rate directives require that the IP rate shall be based on the Administrator’s applicable wholesale rates to public body and cooperative customers and the applicable margins, it would be inappropriate for BPA to accept PGP/PNGC’s argument that service to the DSIs is required to be based on a different resource pool, resulting in a rate that has no relation to either the PF rate or the “floor rate.”

PGP/PNGC argue that BPA may not create a load after-the-fact by contract and then essentially bootstrap that load onto the FBS. PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01, at 13. This argument is not relevant in this instance for the reasons previously stated. Moreover, this is not the manner in which BPA determined to sell power to the DSIs or to establish applicable rates for such sales. Instead, BPA determined that it would exercise its statutory authority to serve the DSIs. The size of the FBS was properly determined after taking into consideration BPA’s replacements of the reductions in capability of the FBS. The DSI rate was developed in accordance with applicable rate directives. Despite PGP/PNGC’s protestations, these decisions do not implicate preference and priority provisions. Nor does the fact that contracts with the DSIs were signed after BPA’s May Proposal add credence to PGP/PNGC’s argument or change the conclusion that the Administrator acted consistent with preference and priority provisions in the sale of federal power.

Similarly, as noted above, BPA has the authority to replace the reductions in the capability of the FBS. There is no statutory limit on the amount of such replacements except for the amount of lost FBS capability. Indeed, Congress envisioned a specific list of resources as FBS resources. If these resources had not lost capability since enactment of the Northwest Power Act, the FBS would be quite large, existing in its full capability. Because the FBS would be in excess of preference customers’ loads, the cost of FBS resources would be allocated in accordance with the Northwest Power Act’s rate directives. This means that, for example, such resources would have been directly allocated to the DSIs under BPA’s pre-July 1, 1985, rate directives. Indeed, this is exactly the manner in which section 7 of the Northwest Power Act works. For example, in

BPA's 1981 Rate Case ROD, the first such ROD under the Northwest Power Act, the Administrator described the fact that FBS resources were properly allocated to BPA's section 7(b) loads (preference and IOU requirements loads) and then to section 7(c) loads (DSI loads):

In the COSA, a sufficient amount of federal base system resources were assigned to the 7(b) rate pool to serve the entire 7(b) load. The proportionate cost of these resources was the basis for determining the proposed PF-1 rate. A small amount of federal base system was not required to serve 7(b) loads. The costs of the remaining portion of federal base system resources, and all the costs of resources acquired through the residential exchange were assigned to be recovered from the 7(c) loads. These costs were the basis for determining the proposed IP-1/MP-1 rate.

*See Administrator's ROD, 1981 Transmission Rate Proposal and 1981 Wholesale Power Rate Proposal, at VI-9. The DSIs' rate is now set based on the PF rate plus a margin, 16 U.S.C. § 839e(c), although BPA's basic cost allocations pursuant to the rate directives continue into present ratemaking.*

PGP/PNGC argue that BPA's interpretation of the law in sections 6(a) and 3(10) of the Northwest Power Act somehow ignores preference rights and renders section 6(b) of the Act meaningless. PGP/PNGC Ex. Brief, WP-02- R-PG/PN-01, at 13-14. Section 6(a)(2) of the Act does not limit resource acquisitions to the amounts needed to meet customers' net requirement regional 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). PGP/PNGC also cite section 5(g) of the Act, which addresses the manner in which initial long-term power sales contracts are offered to BPA's customers. 16 U.S.C. § 839d(a)(2).

Each of the foregoing provisions is perfectly consistent with BPA's interpretation of the Northwest Power Act. Somehow, PGP/PNGC believe that BPA's interpretation allows BPA to "simply 'forecast' the needs of customers that it 'forecasts' will enter purchase power agreements, and 'forecast' the prices that it and such customers would be willing to agree upon, charging to preference customers the difference between those prices and the cost of acquiring such power." PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01, at 13-14. PGP/PNGC suggest this is an absurd result. PGP/PNGC's description, however, does not accurately reflect BPA's ratemaking.

First, where BPA's customers have 20-year contracts and BPA is developing rates within the term of those contracts, BPA's load forecasts are relatively simple. Where BPA has not yet entered a new contracting period after a 20-year contract, by definition BPA does not yet have the contract data that allows a simple forecast of loads. By necessity, BPA must forecast BPA's

expected loads for the new contract and rate periods in order to develop new wholesale power rates. For example, BPA can make reasonable forecasts of such loads based on customers' interest in new contracts; the amount of customer load previously served by BPA; BPA's policy decisions regarding how much power to sell to such discretionary loads; and how BPA's rates compare to market prices. Where BPA has made a policy decision to serve a discretionary load, BPA cannot simply ignore the fact that BPA will in all likelihood have contractual obligations to meet such loads. As provided in section 6(a)(2) of the Northwest Power Act, BPA may acquire resources to meet its contractual obligations. This does not create an absurd result.

PGP/PNGC argue that BPA exaggerates the authority conferred on BPA by section 3(10) of the Act to replace reductions in the capability of FBS resources, or, as characterized by PGP/PNGC, "to purchase power to serve DSI loads and charge preference customers costs of those purchases." PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01, at 14. PGP/PNGC argue that because BPA's new contracts with the DSIs are not the DSIs' original 20-year contracts, the new DSI contracts are not statutorily mandated. *Id.* at 15. BPA agrees. PGP/PNGC argue that the new DSI contracts are subject to preference and priority provisions of applicable statutes. *Id.* BPA agrees. These facts, however, do not show that BPA has exaggerated its authority under section 3(10) of the Northwest Power Act.

Section 3(10) of the Act continues to provide that BPA may replace reductions in the capability of the FBS up to the level of that reduced capability. This is what BPA has done. There is no statutory provision that states that BPA's replacements of reductions in the capability of the FBS are limited by anything other than the amount of such reductions. The fact that Congress deemed BPA to have sufficient resources for purposes of entering into BPA's initial 20-year power sales contracts does not mean that BPA lacks authority to purchase power to meet its contractual obligations after 2001. Such authority is provided in section 6 of the Act. 16 U.S.C. § 839d.

PGP/PNGC argue that the legislative history of the Northwest Power Act shows that Congress did not intend preference customers to bear the costs of DSI sales. PGP/PNGC Ex. Brief, WP-02-B-PG/PN-01, at 15-17. In an attempt to support their argument, PGP/PNGC argue that the legislative history states that preference customers' rates would not be increased as a result of sales to DSI customers that were mandated by the Act, *citing* H.R. Rep. No. 96-976, Pt. II, 96<sup>th</sup> Cong., 2d Sess. 36 (1980). In fact, however, the cited legislative history merely states that the lowest rates were expected to be reserved for preference requirements loads and the residential loads of the Residential Exchange Program. This is true under BPA's proposed rates. The legislative history also notes that the DSIs' rates were different prior to and after July 1, 1985. *Id.*

Prior to July 1, 1985, the legislative history notes that the DSIs picked up the costs of the Residential Exchange Program and the DSIs' "higher rates make it possible for the residential and small farm consumers served by the region's investor-owned utilities to share in the economic benefits of the federal resources without increasing power costs for preference utilities and their customers." *Id.* PGP/PNGC argue that this same language also applies to the DSIs' post July 1, 1985, rates, which are "based on the retail industrial rates charged by BPA's preference utility customers." *Id.* BPA's rates are again consistent with the legislative history

because BPA has established the DSIs' rates consistent with section 7(c) of the Northwest Power Act, and such rates are based initially on the retail industrial rates charged by BPA's preference utility customers. The DSI rate during the upcoming rate period is actually the floor rate that requires that the DSI rate be no lower than the rate in effect in 1985. Still the rates are initially based on PF and then compared to the floor rate thereafter.

Finally, PGP/PNGC note that the legislative history states that the section 7(b)(2) rate ceiling was "hypothetically intended to insure that these customers' rates would 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." PGP/PNGC Ex. Brief, WP-02-B-PG/PN-01, at 16, *citing* H.R. Rep. No. 96-976, Pt. II, 96<sup>th</sup> Cong., 2d Sess. 36 (1980). Notably, the cited language says that section 7(b)(2) was "*hypothetically*" intended to insure that preference customers' rates would be no higher than absent certain transactions. In fact, however, section 7(b)(2) itself is what guides BPA's ratemaking. Section 7(b)(2) prescribes a specific list of assumptions to be incorporated into the rate test. BPA has previously developed a Section 7(b)(2) Legal Interpretation, a Section 7(b)(2) Implementation Study, and develops Section 7(b)(2) Rate Test Studies in each of its rate cases. BPA has complied with the requirements of section 7(b)(2) and its legislative history. Thus, while PGP/PNGC attempt to use the legislative history to bolster their argument, an analysis of the legislative history does not justify their position.

PGP/PNGC also cite legislative history for the proposition that preference customers retain not only preference and priority to FBS resources, but also the price advantage of them. PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01, at 16-17. The legislative history of the Administrator's authority to purchase power to meet BPA's loads states that:

With this authority, the Administrator would be permitted to enter into contracts promising to meet the future net requirements of his authorized customers and additional qualified customers. With such contracts, the preference customers could be assured of having all their future needs satisfied and, pursuant to provisions of the Committee amendment, could maintain their existing preference *to the supply and price of that power.*"

H.R. Rep. No. 96-976, Pt. I, 96<sup>th</sup> Cong., 2d Sess. 28-29 (1980) (emphasis added.) First, this statement is taken out of context, which was the Commerce Committee's discussion of BPA's resource acquisition authority granted under the Act, and not its rate directives. The Committee understood that in order for BPA to offer initial contracts and avoid an "allocation" of federal power among its customers, it had to provide a solution. The solution was both "deeming" BPA to have sufficient resources to offer initial contracts in section 5(g)(7), and authorizing BPA to acquire additional future resources. By providing the acquisition authority, the Committee was stating that preference customers would continue to obtain the power supply needed and that they would have a low cost rate. The Commerce Committee was not stating that the legislation enacted a "preference to price." The Interior Committee's view of the same provision would contradict any such assertion. The Interior Committee stated:

Section 6 of this legislation authorizes and requires the Administrator of BPA to acquire on a long term basis sufficient resources to meet his section 5 contractual obligations to his customers. This resource acquisition authority, by providing the Administrator with the ability to expand the resource pool available to him, allows him to enter into contracts with preference and investor owned utilities, federal agencies, and direct service industrial customer and obviates the need for him to administratively allocate the limited amount of federal resources among existing and potential claimants. H.R. Rep. No. 96-976, Part II, 96th Cong., 2d Sess, (1980) at 35.

Since the Administrator is both authorized and required to expand the “ pool of resources” to serve all of BPA’s customers, there is no condition on such acquisition authority that gives public utility customers preference to price. Instead, Congress directed the Administrator to follow the directives of section 7 in setting his rates for power sold to preference and other customers. Again, the Interior Committee stated, “Section 7 of the legislation sets out the requirements BPA must follow when fixing rates for the power sold its customer under this legislation.” *Id.* at 36.

The quoted language confirms BPA’s position that BPA can acquire resources to meet the needs of its customers, in this case BPA’s preference customers. The language, however, does not limit BPA’s acquisition authority to BPA’s preference customers because the Northwest Power Act expressly states that “the Administrator shall acquire, in accordance with this section, sufficient resources to meet his contractual obligations . . .” 16 U.S.C. § 839d(a)(2). This language is *not* limited to preference customers or net requirements loads. Also, BPA has always ensured that the power requirements of BPA’s preference customers are satisfied. While the quoted language mentions price, there is no language in the Northwest Power Act that establishes a preference to price. Instead, BPA’s rate directives prescribe how BPA develops rates for preference customers, and because such rates are largely based on low-cost FBS resources, the rate directives generally provide BPA’s preference customers with BPA’s lowest firm power rates. This, however, is not a preference to price in the same nature as a preference to supply in the sale of federal power.

PGP/PNGC argue that section 9(i)(1)(A) of the Northwest Power Act bars BPA from charging preference customers the costs of acquiring power to serve DSI loads that have been interrupted or curtailed. PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01, at 17. Section 9(i)(1)(A) provides that “at the request and expense of any customer or group of customers of the Administrator within the Pacific Northwest, the Administrator shall, to the extent practicable, acquire any electric power required by . . . (ii) direct service industrial customers to replace electric power that is or may be curtailed or interrupted by the Administrator (other than power the Administrator is obligated to replace), with the cost of such replacement power to be distributed among the direct service industrial customers requesting such power . . .” 16 U.S.C. § 839f(i)(1)(A). This provision applies when the DSI power sale contract provides the Administrator the right to curtail or interrupt power deliveries to the DSIs.

Rather than support the PGP/PNGC’s argument, however, this section proves just the opposite. First, Congress was clearly able to expressly provide that certain costs should only be allocated

to the DSIs and not to preference customers. *Id.* While Congress was capable of doing so, Congress did not expressly provide that the costs of BPA's normal resource acquisitions should only be allocated to the DSIs and not to BPA's preference and other customers. This suggests that Congress did not intend to do so. The curtailment and interruptions referred to in section 9(i) are shorter term in nature and limited by contractual rights.

Finally, PGP/PNGC argue that BPA has broken promises made at an earlier stage in the rate proceeding that preference customers would not be exposed to any costs associated with providing service to the DSIs. *Id.* at 5. No such promises or guarantees were made. In fact, in the May ROD, just the opposite point was made: "BPA subsequently enhanced the offer it would be willing to propose in the rate case to include 1,500 MW of power at a rate of 23.5 mills/kWh, and this offer came to be known as the Compromise Approach." 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 the Compromise Approach." May ROD, WP-02-A-02, at 15-62. In other words, BPA made it clear that the Compromise Approach would entail costs to other customers, which made the support of the DSIs critical to BPA's support for it in the rate case. The central purpose of the Compromise Approach for service to the DSIs was to address the problem of "survivability" of the Pacific Northwest smelters. Berwager, *et al.*, WP-02-E-BPA-09, at 10-11. A central component of the Compromise Approach was to provide a sufficient amount of power at rates below market alternatives, so that a typical smelter's probability of survival in the global aluminum market would be improved. *Id.*

In the May ROD, the Administrator noted that 990 MW of cost-based power would be used in the determination of the IPTAC rate. May ROD, WP-02-A-02, at 15-70. At that point in time, the allocation of megawatts between the IP rate and the TAC rate was achieved in a manner that placed no upward pressure on the rates of preference customers, consistent with the Administrator's stated goal of avoiding an increase in preference customer rates over 1996 rates. *Id.* However, after publication of the May ROD, skyrocketing prices in the electric power markets complicated matters, both in terms of BPA's ability to serve load and the DSIs' ability to survive in the current market. The prospects of survivability for the aluminum smelters dimmed, as did the possibility of avoiding rate increases. Thus, from today's perspective, it might be argued that BPA has not been able to achieve all of the goals it articulated in the May ROD. In response, however, it can also be maintained that, in spite of unprecedented market volatility, BPA has, to the extent possible, retained the fundamental principles of BPA's Power Subscription Strategy. Burns and Berwager, WP-02-E-BPA-70, at 6.

Increased loads and higher market prices have made it likely that all customers will see higher rates, at least in the near term. *Id.* at 3. But PGP/PNGC's assertion that, as a result, the DSIs are getting special treatment, or that preference customers are being unduly burdened, is an exaggeration. The Compromise Approach contains a meld of power allocated to the IP rate plus a quantity of power priced at the Targeted Adjustment Charge (TAC) rate. Berwager, *et al.*, WP-02-E-BPA-09, at 1-2. These base rates are being treated the same as all others in BPA's Supplemental Proposal, that is, they are not being changed. Burns and Berwager, WP-02-E-BPA-70, at 13. Nevertheless, it is important to recall that the DSIs' purchases of power will still be fully subject to the LB CRAC, FB CRAC, and SN CRAC, the same as other

customer groups. Overall, the DSI Compromise Approach has been designed in a manner that is equitable, not just for the DSIs, but for other customer groups as well.

In summary, BPA has not neglected its obligations under statutory provisions providing preference and priority rights, nor has it rendered such provisions meaningless, as charged by PGP and PNGC. Such provisions do not require that the Administrator refrain from exercising discretionary authority to serve DSI load or from replacing reductions in the capability of FBS resources. BPA has properly allocated the costs of the FBS and set the DSI rate in accordance with statutory directives.<sup>1</sup>

### **Decision**

*The issue of whether the Administrator has the authority to make power sales to the DSIs is not decided in BPA's rate cases, but rather in the development and offer of BPA's power sales contracts. In any event, however, BPA can legally enter into contracts for the sale of power to the DSIs, and such sales do not violate statutory preference and priority provisions or the Northwest Power Act's rate directives.*

## **2.5 Industrial Firm Power Targeted Adjustment Charge Rate**

### **Issue**

*Whether BPA should revise the Industrial Firm Power Targeted Adjustment Charge (IPTAC) rate.*

### **Parties' Positions**

PGP and PNGC argue that given BPA's lack of surplus power and the absence of any legal obligation to serve the DSIs, if BPA elects to sell power to the DSIs, it must do so at market based prices. PGP/PNGC Brief, WP-02-B-PG/PN-01, at 5. They argue that there is no surplus power left, after service to the preference customers to serve the DSIs, and as a consequence, no lower cost power exists to meld with market purchases as contemplated in the May ROD. *Id.* at 8. In the May ROD, BPA also stated that it did "not intend to meld the cost of any augmentation into base rates if doing so would increase those rates above BPA target rates." May ROD, at 70. Given the absence of any surplus, service to the DSIs will increase the costs to BPA's preference customers. PGP/PNGC Brief, WP-02-B-PG/PN-01, at 5. BPA can adjust the IPTAC rate without opening up all base rates by adjusting the surcharge to apply to all DSI load. PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01, at 21-22.

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<sup>1</sup>PGP/PNGC also argue that BPA's interpretation of its authority under the Northwest Power Act is not entitled to deference from the courts. PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01, at 18-21. While it is common for BPA's customers to make such an argument, it is contrary to a long and consistent line of opinions from the Ninth Circuit and the United States Supreme Court. *See, e.g.,* Central Lincoln Peoples' Util. Dist. v. Johnson, 735 F.2d 1101, 1116 (9th Cir. 1984); Aluminum Co. of America v. Central Lincoln Peoples' Util. Dist., 467 U.S. 380, 389-400 (9th Cir. 1984). In any event, it is not necessary to address this issue as BPA's Final Supplemental ROD contains the BPA Administrator's interpretations of the Northwest Power Act. The determination of whether such interpretations are entitled to deference is left to the courts.



Springfield Utility Board (SUB) makes a slightly different argument, but nonetheless argues that BPA should adjust the IPTAC rate to reflect the actual market cost of the power. SUB Brief, WP-02-B-SP-02, at 6. Specifically SUB argues that 496 aMW that is priced at \$28.10/MWh in the calculation of the IPTAC rate should be priced at market cost to BPA to provide that power, as was intended in the May Proposal. *Id.* SUB believes this is consistent with prior statements by BPA regarding the impact of sales to the DSIs on BPA's other customers. *Id.*

In its brief on exceptions, Canby argued the IP TAC rate should be adjusted so there is no cost shift to public customers. Canby Ex. Brief, WP-02-R-CA-02, at 31.

### **BPA Staff Position**

BPA initiated this phase of the proceeding to address the problems presented by the unanticipated increases in loads that required BPA to make purchase requirements in a market that had higher and more volatile prices than forecasted in the May ROD. Burns and Berwager, WP-02-E-BPA-62, at 3. One of the fundamental principles BPA adopted with both the Amended and Supplemental Proposals was that the solution should require limited revisions to the May Proposal. *Id.* at 4. The three part CRAC solves the cost recovery problem created by the combination of increased loads and higher and more volatile prices without requiring BPA to adjust the rates in the May Proposal. Burns and Berwager, WP-02-E-BPA-75, at 5.

### **Evaluation of Positions**

BPA's Amended and Supplemental Proposals are limited to developing risk tools necessary to deal with the combination of unanticipated increases in loads and purchase requirements with higher and more uncertain market prices, although the parties were not limited in the issues they could raise. Burns and Berwager, WP-02-E-BPA-75, at 4-5. While adjusting base rates is certainly an option, BPA believes that such an approach would necessitate a comprehensive review and amendment of the entire 2002 proposed base rates. *Id.* Adopting one of the proposals suggested by the parties would require BPA to engage in a rate development process that it believes is unnecessary. *Id.* at 5. When this phase of the proceeding was initiated, BPA stated that it could effectively deal with the problem through a redesign of the CRAC and corresponding adjustments to the Slice product. *Id.* While there has been continued deterioration in market conditions since the Amended Proposal, the Partial Stipulation and Settlement Agreement demonstrates that BPA staff, as well as the settling parties, continue to believe that this problem can be addressed without revisions to the base rates. *Id.* There is no substantive reason to single out the IPTAC rate for such treatment and to do so would be inappropriate. *Id.*

### **Decision**

*There is no need to revise the IPTAC rate.*

## 2.6 Tiered Rate Proposals

### Issue

*Whether the DSI proposal to tier rates now is an appropriate way of dealing with unanticipated increases in loads and purchase requirements in a higher and more volatile market.*

### Parties' Positions

The DSIs note that the problem BPA is attempting to address in this proceeding is the need to make market purchases that are greater than initially forecasted in the May ROD in a market that is higher and more volatile. DSI Brief, WP-02-B-DS/AL-02, at 9. The DSIs contend that the appropriate way to deal with this combination of problems is through a tiered rate proposal where every customer can purchase approximately 75 percent of its power need at an embedded cost rate and would have the option to purchase the last 25 percent at market based rates. *Id.* They contend that their proposal sends the appropriate price signals to customers and gives each customer the ability to purchase some power at BPA's embedded cost rate. *Id.* at 11. The DSIs believe that their proposal will also provide additional incentives for customers to conserve or meet their power needs through their own generation or power purchases on the market. *Id.* at 13.

The Joint Customer Group (JCG) and Western Public Agencies Group (WPAG) argue for the rejection of tiered rates in this proceeding. JCG Brief, WP-02-B-JCG-01, at 15; WPAG Brief, WP-02-B-WA-01, at 12. They contend that, contrary to the arguments in the DSI brief, the DSI tiered rate proposal would require material revisions to the base rates adopted in the May ROD. JCG Brief, WP-02-B-JCG-01, at 15; WPAG Brief, WP-02-B-WA-01, at 14. This would require the performance of both the 7(b)(2) rate test as well as the 7(c) floor calculation. JCG Brief, WP-02-B-JCG-01, at 15. The JCG and WPAG also note that the DSI tiered rate proposal would require BPA to allocate power differently from the method adopted in the Subscription Strategy. JCG Brief, WP-02-B-JCG-01, at 15; WPAG Brief, WP-02-B-WA-01, at 13. The JCG and WPAG argue that the DSI tiered rate proposal raises cost shift and equity issues by allowing the DSIs to purchase approximately 1,000 megawatts (MW) of power at \$23/MWh. JCG Brief, WP-02-B-JCG-01, at 16; WPAG Brief, WP-02-B-WA-01, at 12-13. They contend that this would result in a \$1.6 to \$1.8 billion per year subsidy to the DSIs. JCG Brief, WP-02-B-JCG-01, at 16; WPAG Brief, WP-02-B-WA-01, at 12-13. The JCG and WPAG believe that the tiered rate proposal is also designed in a fashion that advantages the DSIs because of their ability to reduce 25 percent of their load and avoid the marginal tier. JCG Brief, WP-02-B-JCG-01, at 16; WPAG Brief, WP-02-B-WA-01, at 12. WPAG also notes that there is no clear concept of how the DSI tiered rate proposal would apply to the Slice product, for which BPA has no obligation to deliver a firm amount, and which includes both firm and surplus power. Slice product implementation would present special challenges under a tiered-rate proposal. *Id.* at 14.

Northwest Requirements Utilities (NRU) also argue that BPA should reject the DSI tiered rate proposal because it is nothing more than an attempt by the DSIs to shift the cost of augmenting the system from the DSIs to BPA's other customer classes. NRU Brief, WP-02-B-NI-03, at 12-13.

Canby believes the Administrator made the correct decision when he rejected the DSI tiered rate proposal. Canby Ex. Brief, WP-02-R-CA-02, at 31.

### **BPA Staff Position**

As explained in BPA's testimony in December 2000, the combination of an unanticipated increase in loads and purchase requirements, with higher and more uncertain market prices, greatly diminishes the probability that the base rates proposed in the May Proposal will fully recover generation function costs. Burns and Berwager, WP-02-E-BPA-62, at 3. Absent a change to the May Proposal, TPP would be reduced to below 70 percent, a level which falls well short of specific goals and targets. *Id.* BPA has a serious cost recovery problem that it is obliged to address by reason of statute and Administration policy. *Id.* BPA believes that it can most effectively deal with this problem through a redesign of the risk mitigation tools and corresponding changes to the Slice methodology. *Id.* at 4. For the reasons explained in greater detail in section 7.1 of this Supplemental ROD, BPA believes that tiering the rates is clearly not appropriate at this time.

### **Evaluation of Positions**

The current rate proceeding is the culmination of a several year process that started with the Subscription Strategy. Burns and Berwager, WP-02-E-BPA-75, at 2. During the Subscription Strategy the concept of tiered rates was proposed and rejected by the region. *Id.* This rate case is the implementation of the pricing concepts that came out of the Subscription Strategy. *Id.* One of the decisions made in the Subscription Strategy was a proposal to allow public agency customers to subscribe at the lowest cost Priority Firm Power (PF) rate for all load not currently being served by customers' generating resources. *Id.* at 3. The Subscription Contracts were designed to offer power based on average rates not tiered rates. *Id.* To layer a tiered rate proposal on the current contracts at this point, without extensive regional consultation and review, would not be appropriate.

In addition, given the current allocation of federal power, imposing a tiered rate proposal on the existing allocation of resources would not necessarily result in the desired economic efficiencies. *Id.* As explained in detail in section 7.1, the DSI and IOU contracts clearly did not contemplate a tiered rate concept. If the region were to consider tiered rates, there would need to be a similar discussion of the allocation of the federal resources. *Id.* Any allocation of resources among customer groups should be done *after* (rather than before) the decision to tier rates has been made to avoid layering the concept on contracts that were not designed to implement tiered rates. *Id.*

Furthermore, given the extensive regional discussion that would accompany any decision regarding tiered rates, implementing them at this time would not be appropriate. *Id.* BPA needs to have rates in place by October 1, 2001. *Id.* Conducting the regional discussion that would accompany such a decision is not possible at this point in time. *Id.*

## **Decision**

*The DSI proposal to tier rates at this time is not an appropriate way of dealing with unanticipated increases in loads and purchase requirements in a higher and more volatile market.*

## **2.7 Power System Emergency Issues**

### **Issue 1**

*Whether BPA's adoption and application of criteria for declaring a power system emergency under the 2000 Biological Opinion (BO) is within the scope of this rate proceeding.*

### **Parties' Positions**

Northwest Energy Coalition (NWECC) contends that a legal question exists with regard to adopting and applying criteria for declaring a power system emergency under the BO. NWECC/SOS Brief, WP-02-B-NA/SA-02, at 10. NWECC/SOS Ex. Brief, WP-02-R-NA/SA-02, at 8-13.; CRITFC Ex. Brief, WP-02-R-CR/YA-02, at 5. NWECC contends the criteria "are not the product of the Administrator's exercise of duties and thus are an impermissible sub-delegation of statutory power unless done in accordance with other laws and process for negotiated decision-making." NWECC/SOS Brief, WP-02-B-NA/SA-02, at 10. NWECC believes that BPA failed to comply with either the Federal Advisory Committee Act (FACA) or the Administrative Procedures Act (APA) in developing these criteria. *Id.* at 11-12. BPA also did not develop these criteria in this rate proceeding. *Id.* at 12.

Columbia River Inter-Tribal Fish Commission (CRITFC) contends that BPA cannot rely on the criteria for declaration of an emergency because the provisions are vague and BPA should not rely on the National Marine Fisheries Service's (NMFS) interpretation of BPA's obligations under the BO. CRITFC Brief, WP-02-B-CR/YA-02, at 17.

In their briefs on exceptions the JCG, WPAG, and NRU all argue that BPA's declaration of a system emergency is not an issue in this rate proceeding. JCG Ex. Brief, WP-02-R-JCG-01, at 5; WPAG Ex. Brief, WP-02-R-WA-01, at 4-5; NRU Ex. Brief, WP-02-R-NI-01, at 4.

### **BPA Staff Position**

The legal questions regarding the establishment of the criteria for the declaration of a power system emergency under the 2000 BO are not issues that are within the scope of this proceeding.

### **Evaluation of Positions**

Neither NWECC nor CRITFC raised this issue in their direct or rebuttal testimony, nor did they raise this issue with any panel during the course of cross-examination. Now for the first time in the briefs, NWECC and CRITFC claim that BPA did not adopt and apply the power system emergency criteria in a manner consistent with the FACA or the APA. Alternatively, they argue

that BPA cannot rely on NMFS' interpretation of the criteria. However, even if these issues had been raised earlier, the manner in which BPA and the other federal agencies developed and interpreted the criteria for the declaration of a power system emergency under the 2000 BO are not matters that are within the scope of this rate proceeding. This proceeding is designed to deal with the establishment of BPA's power rates for the FY 2002-2006 rate period. If NWECC believes that BPA and the other federal agencies have not developed the criteria in a manner that is consistent with the law, there are other forums in which to address this issue.

### **Decision**

*Development of criteria for the declaration of a power system emergency is not an issue within the scope of this rate proceeding.*

### **Issue 2**

*Whether the adoption of the criteria for the declaration of a power system emergency is within the scope of this rate proceeding.*

### **Parties' Positions**

NWECC argues that BPA needed a National Environmental Policy Act (NEPA) analysis supplementing the Business Plan EIS before adopting the criteria for declaring a power system emergency because of the potential impact on fish. NWECC/SOS Brief, WP-02-B-NA/SA-02, at 13.

### **BPA Staff Position**

Whether BPA needs to perform any environmental analysis before the establishment of the criteria for declaring a power system emergency is not an issue in this rate proceeding.

### **Evaluation of Positions**

NWECC contends that some environmental analysis should have been performed before BPA and the other federal agencies established the criteria for the declaration of a power system emergency. Whether BPA was or was not obligated to perform such an analysis is not an issue in this rate proceeding for the same reasons cited in Issue 1 above.

### **Decision**

*BPA's obligations concerning an environmental analysis of the impacts on fish before adopting the criteria for declaring a power system emergency are not an issue in this rate proceeding.*

### **Issue 3**

*Whether BPA's recent declaration of a power system emergency is an issue in this rate proceeding.*

## **Parties' Positions**

NWEC argues that the recent declarations of power system emergency evidences BPA's unwillingness to meet its fish and wildlife obligations. NWEC/SOS Brief, WP-02-B-NA/SA-02, at 19. They contend that, while BPA was technically allowed to declare the emergency, it should have looked at alternatives such as raising rates or buying power from marketers. *Id.* at 19. NWEC contends that BPA's failure to pursue one of these alternatives demonstrates an unwillingness on BPA's part to pay the price for fish and wildlife during the 2002-2006 rate period. *Id.* at 20.

CRITFC argues that BPA's declaration of a power system emergency is not based upon sound legal principles and that the declarations should stop until BPA has demonstrated that all possible steps have been taken to alleviate the problems. CRITFC Brief, WP-02-B-CR/YA-02, at 16.

## **BPA Staff Position**

During every portion of this rate proceeding BPA has declared that it will meet both the financial and operational requirements under the Endangered Species Act (ESA). Burns and Berwager, WP-02-E-BPA-75, at 8. The BO provides for deviations from the operational requirements for power system emergencies. BPA does not believe that the recent declarations have any relevance to the setting of rates in the 2002-2006 rate period. BPA did not raise rates during this rate period or make market purchases to avoid the declarations because those are not realistic solutions. It would not have been feasible to raise rates during the current rate period to generate sufficient revenues in time to avoid the declarations. Similarly, while market purchases in theory can help avoid the declarations of a power system emergency they are not always a viable solution. Whether BPA could or should have avoided the recent declarations of power system emergency is not an issue in this proceeding.

To the extent that NWEC or CRITFC's comments regarding the recent declarations of power system emergency touch on a matters that are at issue in this rate proceeding, the only relevant question is whether BPA will meet its fish and wildlife obligations in the coming rate period. BPA believes that the risk mitigation package in this proposal will allow BPA to meet its fish and wildlife obligations. Burns and Berwager, WP-02-E-BPA-75, at 7.

## **Evaluation of Positions**

NWEC and CRITFC both argue that there are alternative actions BPA can undertake to avoid the declaration of a power system emergency. CRITFC Brief, WP-02-B-CR/YA-02, at 16; NWEC/SOS Brief, WP-02-B-NA/SA-02, at 19. They contend BPA has failed to look at these alternatives when it declared the recent emergencies. *Id.* They argue that BPA's failure to pursue alternatives to the declaration of an emergency demonstrates an unwillingness on the part of BPA to comply with its fish and wildlife obligations during the upcoming rate period. *Id.*

NWEC and CRITFC's contentions that the recent declarations of power system emergency should have been avoided by raising rates or buying power on the open market is not an issue in this rate proceeding. These declarations have no bearing on the ability of BPA to meet its fish

and wildlife obligations in the coming rate period. NWECC and CRITFC, nonetheless, suggest that these declarations constitute some kind of evidence of future behavior by BPA and argue by inference that the current rate proposal will not be adequate to meet BPA's fish and wildlife obligations. With regard to the argument that the declarations demonstrate future behavior, this is not a rate case issue. Furthermore, even if one could argue it is, there is no evidence on the record to support this unfounded allegation. BPA has stated that it will meet all its fish and wildlife obligations. Burns and Berwager, WP-02-E-BPA-75, at 7. BPA was acting within the terms of the BO when it declared the recent emergencies. *Id.*

With regard to the implication that these declarations somehow demonstrate the inadequacy of the current proposal, this allegation is also unsubstantiated and is not a rate case issue. Even if it were an issue in this proceeding, NWECC and CRITFC's argument ignores some fundamental differences between the rates being put in place in this proceeding and those currently in place. As addressed more fully in the Risk Mitigation Chapter, BPA's proposed rates have a more robust risk mitigation package than is currently in place. The combination of the FB and SN CRACs provide BPA with considerably more risk mitigation protection than is currently in place. This is not to say that had BPA had these proposed mechanisms in place it necessarily would have been able to avoid the declaration of emergencies in this rate period. However, BPA will have a risk mitigation package that will place it in a better position to deal with future variations in hydro conditions.

An underlying assumption of both NWECC's and CRITFC's argument is a belief that there is always a financial mechanism BPA can employ to avoid declaring virtually every emergency. In theory, if there were an unlimited supply of dollars and there was always an available alternative source of power, it should be possible for BPA to avoid virtually all power system emergencies. However, the Principles that have shaped this rate case require that BPA treat its fish and wildlife obligations equivalent to its power obligations. The balance that NWECC and CRITFC argue for no longer would create balance between these somewhat competing obligations, but rather would require BPA to place its fish and wildlife obligations above all other obligations. The practical realities and BPA's legal obligations do not require BPA to protect against every potential problem. By working with the other federal agencies and acting within the scope of the provisions of the BO, BPA and the other agencies have developed criteria to address the circumstances in which BPA can operate outside the bounds of the operational requirements of the BO.

### **Decision**

*BPA's recent declaration of a power system emergency is not an issue in this rate proceeding. Additionally, these declarations do not evidence BPA's unwillingness to meet its fish and wildlife obligations in the coming rate period nor the inadequacy of the Supplemental Proposal to meet future fish and wildlife obligations.*

## **2.8 Burbank Contract Issues**

### **Issue 1**

*Whether the application of the FB CRAC to the adjustment of Burbank's formula contract rate requires the application of the Dividend Distribution Clause (DDC) as well.*

### **Parties' Positions**

Burbank argues that the FB CRAC is an upward adjustment to rates if the Accumulated Net Revenues (ANR) drop below certain threshold levels. WP-02-B-BU-01, at 5. Burbank Ex. Brief, WP-02-R-BU-01, at 2-4. Burbank believes that BPA is planning upon treating Burbank unfairly because it intends to apply the FB CRAC but not the DDC to the calculation of the contract rate. *Id.*

### **BPA Staff Position**

The application of the FB CRAC and the DDC are not related matters. The FB CRAC is an upward adjustment to rates that would occur in the event that ANR drop to some predefined threshold. WP-02-E-BPA-68, at 10. The DDC, on the other hand, is not an adjustment to rates but rather is a dividend that is distributed to a defined set of BPA customers purchasing under certain specified rate schedules. Specifically with respect to Burbank, its purchase from BPA pre-dates Subscription; it is not a Subscription purchase under the FPS rate schedule. Burbank is not a customer that is eligible for the DDC.

### **Evaluation of Positions**

Burbank claims that BPA's rate design links the eligibility for the application of the FB CRAC with the DDC. Burbank Brief, WP-02-B-BU-01, at 6; Burbank Ex. Brief, WP-02-R-BU-01, at 2-4. Burbank argues that if BPA is going to adjust the formula rate contained in its contract for upward adjustments due to the FB CRAC, it would be unjust not to make a similar adjustment for the DDC. *Id.*

Burbank assumes that because the calculation of the formula rate in its contract uses the FB CRAC, there should be a similar adjustment for the DDC. This assumption is invalid and is inconsistent with the provisions in its contract. Burbank does not purchase power from BPA under the PF rate schedule, but rather its contract has a rate which is adjusted to reflect changes in PF rates. The formula in Burbank's contract uses a weighted average of the PF rates to calculate the rate adjustment for its contract, WP-02-E-BU-02. Burbank's contract formula provides that the new contract rate will be calculated by multiplying the existing contract rate by the new average of PF rates divided by the previous average PF rates. *Id.*

Therefore, if the new average PF rate is larger than the previous PF rate, there will be an upward adjustment to the rate in Burbank's contract. The adjustment to the Burbank contract is specifically tied to adjustments to the PF rates, which would include the LB, FB, and SN CRACs.



The DDC, on the other hand, is not an adjustment to the PF rate or rates, but rather, it operates as a credit to a customer's bill in the event that ANR reach certain pre-established levels. Therefore, any DDC does not change the PF rates. Eligibility for the DDC is limited to customers purchasing under specified rate schedules. As explained in the Supplemental 2002 GRSPs:

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), New Resource Firm Power (NR-02), and Subscription purchases under Firm Power Products and Services (FPS).

Appendix, WP-02-A-09. Burbank is not eligible to purchase under any of these schedules and, therefore, is not eligible for the DDC.

Because the DDC does not adjust the PF rate levels it cannot be factored into the calculation of the formula contract rate in Burbank's contract. The only way to include the DDC into Burbank's contract would be by renegotiating the formula contract rate to include a credit for the DDC. Contract matters such as this are beyond the scope of this rate proceeding.

### **Decision**

*No adjustment for the DDC will be made in the calculation of Burbank's formula contract rate. Renegotiation of Burbank's formula contract rate is not an issue that is within the scope of this rate proceeding.*

### **Issue 2**

*Whether the PF Exchange rate should be included in the calculation of the weighted average PF rate in Burbank's contract.*

### **Parties' Positions**

Burbank believes the PF Exchange rate should not be factored into the calculation of the weighted average PF rate because the rate is for a different class of service. Burbank Ex. Brief, WP-02-R-BU-01, at 4-6. Burbank Brief, WP-02-B-BU-01, at 8. Burbank argues that its contract requires that the adjustment shall be for the same class, quality, or type of service under its contract. *Id.* at 9. Burbank notes, however, that if the PF Exchange rate is used, it should have no impact on the calculation of the weighted average since there are no sales forecasted by BPA under those rate schedules. *Id.* at 10.

In its brief on exceptions, Burbank contends that this issue, which it raised in its initial brief, is outside the scope of this proceeding. Burbank Ex. Brief, WP-02-R-BU-01, at 5.

## **BPA Staff Position**

Burbank relies on contractual provisions that are not on the record to argue that the PF Exchange rate should be excluded from the calculation of the formula rate in its contract. Even if the contractual provision relied on was in the record, Burbank's interpretation of the impact on the determination of the formula rate is in error. The provision of the General Contract Provisions (GCPs) cited by Burbank to argue that the PF Exchange rate is of a different class of service is misplaced. The provision of the GCPs relied upon by Burbank does not apply to its contract. The GCPs are contract provisions that were attached to all BPA contracts that contain a conflict provision that requires the body of the contract to control over the GCPs if a conflict exists. Section 2(a). Given the conflict between the body of the contract and the GCPs, the body of the contract controls. Therefore, to the extent that there are sales under the PF Exchange rate, they should be included in the calculation of the formula rate in Burbank's contract.

## **Evaluation of Positions**

Burbank relies upon a contractual provision [section 6(c)] that is not in the record to argue that the PF Exchange rate is not an appropriate PF rate to use in the calculation of the formula rate in its contract.<sup>2</sup> Given the absence of any evidence in the record to support Burbank's position, there is no way of substantiating its argument unless one goes outside the record to examine and interpret the contract language in question.

Burbank's contract formula states:

The newly adjusted average PF rate or successor rate(s) in mills per kWh. Such average PF rate shall be calculated at a load factor of 50 percent, and assuming a uniform demand in all months. If there is more than one PF rate, the average shall be determined by a weighting based on forecasted sales under such PF rates.

WP-02-E-BU-02.

The specific language contained in this section, that is on the record, evidences an intent to include in the calculation all PF rates in the calculation of the formula rate. Rather than providing for an exception, the stated intent of the section is to include all PF rates in the calculation. There is no evidence on the record to support Burbank's argument, and the evidence on the record demonstrates a contrary intent.

Burbank also argues that there will be no sales under the PF Exchange rate and therefore it should not be factored into the calculation of the formula rate. Whether there are forecasted sales under the PF Exchange rate will be determined at the time the calculation of the adjustment is made. To the extent that there are sales forecasted under the PF Exchange rate they will be included in the calculation of the formula rate in the Burbank contract.

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<sup>2</sup> Burbank introduced into evidence only one section of its contract, section 9(a)(3), which does not have any of the referenced language.

In the brief on exceptions, Burbank makes the argument that the decision in the Draft ROD was faulty because the record on the issue is limited. Burbank Ex. Brief, WP-02-R-BU-01, at 5. The obligation to develop a record upon which the Administrator can base his decision is the responsibility of the party asserting the claim. The fact that Burbank did not enter materials into the record in support of its arguments does not make the Administrator's decision faulty.

### **Decision**

*The forecasted sales under the PF Exchange rate should be included in the calculation of the weighted average PF rate in the Burbank contract.*

### **Issue 3**

*Whether the cost of service to the DSIs, which is in part included in the PF rate, should be part of the calculation of the contract rate for Burbank's contract.*

### **Parties' Positions**

Burbank argues that BPA cannot legally allocate any of the costs to serve the DSIs in the determination of the PF rates. Burbank Ex. Brief, WP-02-R-BU-01, at 6-8. WP-02-B-BU-01, at 13. Because the augmentation costs to serve all customers, including costs to augment the system to serve the DSIs, are allocated and spread to all customers, Burbank believes the cost of serving the DSIs must be excluded. *Id.*

### **BPA Staff Position**

The sales to the DSIs should not be excluded from the calculation of the formula rate in Burbank's contract. The Burbank contract formula rate is based, in part, on the PF rate. BPA properly calculated the PF rate as shown by the record. Therefore, the cost of serving the DSIs should not be excluded.

### **Evaluation of Positions**

Burbank believes that BPA must exclude any costs associated with service to the DSIs from the PF rates used in the formula rate in its contract. There is no provision in its contract, which allows adjustments to the PF rate calculation to deduct cost components of the PF rate, that Burbank believes are appropriate. Additionally, Burbank has not presented any evidence regarding the level of the adjustment or how this adjustment should be made. Burbank simply concludes that the "costs associated with service to the DSI customers should be totally excluded from the PF preference rates that are factored into the calculation of the adjustment clause." Burbank Ex. Brief, WP-02-R-BU-01, at 7. There is no category of costs designated as the cost of service to the DSIs. Therefore, what costs Burbank considers appropriate, and those it does not, is not presented. Given the lack of any evidence on this matter it is difficult to evaluate the proposal.

However, underlying the argument is a contention by Burbank that BPA cannot legally allocate any of the costs associated with sales to the DSIs to its PF customers. This argument is the same legal argument as PGP and PNGC made regarding the costs of serving the DSIs and was addressed earlier in this chapter. That issue has been fully addressed in this chapter under that issue. *See* section 2.4.

### **Decision**

*BPA will not exclude the costs associated with service to the DSIs from the PF rates for the purpose of calculating the formula rate in Burbank's contract.*

## **2.9 Effects of Bonneville Power Administration's Rate Proposal on the Formation of Tribal Utilities**

As part of its Subscription Strategy, BPA made available 75 aMW for purchase by entities wishing to form new public utilities. Contingent contracts were executed with five such entities that are in the process of forming new public utilities. *See* Burns and Berwager, WP-02-E-BPA-75, at 11. BPA recognized that such entities would not be formed and in compliance with BPA's standards for service as determined by BPA to purchase as a customer prior to the closing of the Subscription window. BPA's performance under the contingent contracts, including the sale of requirements power, will not begin until the entity is a fully qualified public agency or cooperative with the demonstrated ability to take physical delivery of the power for distribution to its retail consumer load. The Confederated Tribes and Bands of the Yakama Nation (Yakama) has formed a utility, Yakama Power, for service to retail load on its reservation. Yakama Power executed a contingent power sale contract. The execution of this contract occurred prior to BPA's decision to amend the WP-02 wholesale power rates through the three-tier CRAC. Yakama Power is not yet a BPA customer.

### **Issue**

*Whether, based on the record of this case, BPA has the statutory authority and case law discretion in setting its rates to allow it to create a special Tribal rate category which would not subject Yakama Power to LB, FB, and SN CRACs.*

### **Parties' Positions**

Yakama contends that BPA should not subject Yakama Power to the proposed three tier CRAC. Instead, Yakama argues that BPA should subject Yakama Power to only the level of the CRAC as published in the Administrator's May ROD. CRITFC Brief, WP-02-B-CR/YA-02, at 26; CRIFC Ex. Brief, WP-02-R-CR/YA-02, at 7-8.

The JCG and the WPAG both oppose any exemption or shield in favor of Yakama Power from paying the full costs of any CRAC imposed by BPA. Brattebo, *et al.*, WP-02-E-JCG-03, at 45; WPAG Brief, WP-02-B-WA-01, at 19.

## **BPA Staff Position**

BPA does not believe that any contingent contract signatory should be exempt from the application of the LB, FB, and SN CRACs. Burns and Berwager, WP-02-E-BPA-75, at 11.

## **Evaluation of Positions**

Yakama makes several arguments to support its position that BPA should subject Yakama Power to only the initial one-level CRAC as of the date Yakama Power signed its contingent power sale contract. Sheets, *et al.*, WP-02-E-CR/YA-06, at 32. This evaluation addresses the Yakama's arguments that BPA has significant statutory and case law discretion in setting its rates which would allow it to create a special tribal rate category. CRITFC Brief, WP-02-B-CR/YA-02, at 30.

Yakama argues there should be a "special rate class" for tribal utilities, and that such treatment would not create an "unfair burden" on or discriminate against BPA's other customers because the "tribes and the other customers are not 'similarly situated.'" CRITFC Brief, WP-02-B-CR/YA-02, at 31. Yakama relies on *Ass'n of Pub. Agency Customers v. Bonneville Power*, 126 F.3d 1158 (9<sup>th</sup> Cir. 1997) (*APAC*) citing *City of Vernon v. FERC*, 845 F.2d 1042 (D.C. Cir. 1988), to support its argument that tribal utilities occupy a "unique niche" in BPA's statutory (and trust responsibility) obligations for special treatment. *Id.* In addition, the Yakama contend there are several points on which to base this distinction: the Tribes are "start up" utilities that, unlike the majority of customers with whom BPA has subscription contracts, have not had the benefit of years of operation and the opportunity to build up reserves to use to pay the CRACs; because of the development of the FCRPS they have suffered cultural, economic and treaty right devastation due to damage of fish runs without receiving the benefit of BPA's low cost rates over the years; they signed enforceable contracts before BPA moved to stay the rate case; and finally, that under the Indian Energy Resources Act of 1992 (IERA) BPA has a specific trust duty toward Indian tribes to assist the Yakama to form a tribal utility. *Id.* at 31-33.

BPA is not persuaded that these arguments in this case justify the treatment the Yakama's seek. Neither the Bonneville Project Act nor the Northwest Power Act contain language expressing a direction to create a special rate class within the public body customer class. Had Congress intended to create a hierarchy of rates for preference customers, particularly one based on tribal status, and the tribes' historical treatment and relationship to the FCRPS, it clearly would have done so. Nor is there any statutory language outside of Northwest Power Act section 7(e) to support administrative discretion to create such a class. Even section 7(e) is neutral on its face, simply placing price signals and rate design under the Administrator's discretion. *See* 16 U.S.C. § 839e(e). Moreover, other customers strongly oppose such special treatment. The JCG argues "there is no rational basis for shielding Yakama Power from these rate increases by shifting these costs to other BPA customers." Brattebo, *et al.*, WP-02-E-JCG-03, at 45; *see also* IOU<sup>3</sup> Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 7. WPAG argues "[g]ranting such exemptions would shift costs to other customers, and would lead to an endless stream of petitioners seeking special

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<sup>3</sup> IOU includes all investor-owned utilities except Montana Power Company. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02.

treatment from BPA. Such an outcome would threaten BPA's financial integrity, and lead to an endless bidding contest." WPAG Brief, WP-02-B-WA-01, at 19.

BPA's governing statutes speak to three customer classes: public body and cooperative utilities (preference customers), IOUs, and DSIs. *See* 16 U.S.C. §§ 839c(b)(1) and 839c(d)(1)(A). Likewise, BPA's rate directives in section 7 of the Northwest Power Act set forth the applicable rate treatment for each class of customer. Rates of general application for power sold to public body and cooperative and federal agency customers purchasing under section 5(b) of the Northwest Power Act are established under section 7(b)(1). Rates applicable to DSIs are established under section 7(c)(1). Rates for service to IOUs are established under section 7(f). When Yakama Power becomes fully qualified to purchase power under its contract it will do so as a public body customer of BPA and will purchase power at rates established pursuant to section 7(b)(1). "The class of customers generally considered within the definition of 'public bodies and cooperatives' is quite large and diverse." *See* S. Rep. No. 96-976, Part II, 96<sup>th</sup> Cong., 2d Sess. at 27 (1980). The language of section 7(b) and the application of the rate test contained in section 7(b)(2) affords this rate class rate protection vis-à-vis other customer classes. Hence, inclusion in this class confers considerable benefits.

Furthermore, the *APAC* decision relied upon by the Yakama does not support its proposition that the tribes are not "similarly situated." In that case, the petitioners alleged that BPA discriminated against retail industrial consumers of BPA's public utilities by offering to wheel non-federal power to the DSIs. Petitioner's alleged that DSIs and the utilities' retail industrial consumers were "similarly situated." The court found that the DSIs and the retail industrial consumers were not similarly situated for several reasons, but mainly because the DSIs had contracts and were customers of BPA and the retail consumers had no contracts with BPA and were not customers of BPA. *APAC* at 1172. Here, in contrast, Yakama Power is similarly situated under the rate directives with BPA's other public body customers that purchase power from BPA. That is not to say, or imply, that there is not ample historical and other basis that could justify creation of a separate tribal rate class; rather, it is to say that unlike the situation where Congress chose to treat DSIs separately from other industries, it did not choose to separate tribal customers from other members of the rate class in the rate directives.

Yakama notes that it is a "start-up" utility which has not had the opportunity to build up reserves to pay the CRACs. CRITFC Brief, WP-02-B-CR/YA-02, at 31. BPA understands that the Yakama are taking the necessary steps to establish a new utility; however, there are other entities also starting up new utilities. "In addition to the two tribal utilities, there are contingent contracts signed by the City of Hermiston, City of Missoula, and Energy Northwest, Inc. (of Montana)." Burns and Berwager, WP-02-E-BPA-75. Like the Yakama, these entities have not benefited from years of operation nor have they had the opportunity to build up reserves to pay the CRACs. And, like the Yakama, these other contingent contract holders will be subject to the amount of the CRAC being assessed at the time they become qualified to purchase power from BPA under their contracts. In regard to the existence and use of reserves by existing customers to offset the CRAC, it is unlikely that any have reserves that can be used to pay the costs associated with the CRAC. BPA's customers are more likely to pass on the CRAC in the form of rate increases to their retail consumers. *See* WP-02-W-ARP-0106 Letter from City of Rupert ("A ninety-five percent increase would cause many individuals, who are on fixed incomes or

otherwise struggling to pay their bills, to find themselves in default or forced to go without heat or the use of electricity.”); WP-02-W-ARP-0027 Letter from Umatilla Electric Cooperative (“If the BPA raises its current wholesale power price in October by 100 percent, UEC’s rates in October could increase by 50 percent or more.”). While BPA is sympathetic to the difficulties faced by new utilities—particularly new utilities forming in volatile power markets—today’s markets and BPA’s potential rate hikes confront all utilities with unprecedented challenges. BPA’s paramount rate setting directive is to set its rates so total revenues continue to recover total costs. 16 U.S.C. § 839e(a); H.R. Rep. No. 976, Part II, 96<sup>th</sup> Cong., 2d Sess. at 36 (1980). In this instance, BPA’s concern with assuring cost recovery outweighs the reserve needs of new and newly formed utilities.

Yakama claims that because of the development of the FCRPS it has suffered cultural, economic and treaty right devastation due to damage of fish runs without receiving the benefit of BPA’s low cost rates over the years. CRITFC Brief, WP-02-B-CR/YA-02, at 32. While BPA is not indifferent to the loss suffered by Yakama, the circumstances related by Yakama call into play policy judgments of the highest order, to wit, the kinds of legislative judgments Congress makes. The IERA is a good example of this kind of legislative activity. As indicated earlier, the rate directives express no judgment that tribal utilities receive special treatment. In the face of that silence, BPA is unprepared to determine that such special rate treatment is warranted. Also, as retail consumers of electricity, Yakama has received the benefits of the FCRPS in several ways. In those portions of Yakama reservation served by an existing BPA preference customer purchasing under the priority firm power rate, such as Benton Rural Electric Association, the retail consumers of Yakama have received the benefits of low cost federal power in the form of low retail rates. Further, those portions of the reservation have also received the benefits associated with the low density discount and applicable irrigation discounts. On the other hand, in areas of the reservation served by IOUs, such as PacifiCorp, the retail rates reflect the benefits of low cost federal power passed on through the residential exchange program and purchases of federal surplus firm power.

Yakama contends that under the IERA, BPA has a specific trust duty toward Indian tribes to assist Yakama to form a tribal utility. CRITFC Brief, WP-02-B-CR/YA-02, at 32. “The IERA specifically requires the DOE, and, accordingly, Bonneville, to assist tribes in energy development ‘in a manner that is consistent with the federal trust and government-to-government relationships between Indian tribes and the federal government.’” Citation omitted. *Id.* Yakama claims that the IERA encourages tribes to establish electric utilities by authorizing DOE to provide grants, loans and technical assistance to tribes for reservation projects involving the transmission of electricity. *Id.* Citation omitted. Yakama claims that making it subject to the CRACs will make its utility uneconomic and thus the “goods sought by Congress in the EIRA cannot be obtained by Yakama.” *Id.* at 33.

BPA disagrees with Yakama’s reading of the IERA and its assertions that it applies to BPA and imposes on BPA a trust responsibility to enable the formation of Yakama Power. The IERA specifically applies to development grants made by the Secretary of the Department of Energy to assist Indian tribes (and joint ventures which are 51 percent or more controlled by a tribe) “in obtaining the managerial and technical capability needed *to develop energy resources on Indian reservations.*” 25 U.S.C. § 3503 (a)(1) (emphasis added). Grants may also be made to assist in

the costs for “vertical integration projects” which entail a “project that promotes the vertical integration of the energy resources on an Indian reservation. Such term includes, but is not limited to, projects involving solar and wind energy, oil refineries, the generation and transmission of electricity, hydroelectricity, cogeneration, natural gas distribution, and clean, innovative uses of coal.” 25 U.S.C. § 3503 (a)(2).

Yakama also states that IERA is intended to encourage tribes to establish electric utilities for reservation projects involving the transmission of electricity. CRITFC Brief, WP-02-B-CR/YA-02, at 25. While Yakama observes some of the goals of the Act, *i.e.*, to enable tribal communities to generate a revenue stream and to foster job creation, *see* CRITFC Brief, WP-02-B-CR/YA-02, at 25, Yakama ignores other critical elements of the Act, namely development of Indian energy resources by Indian tribes.

There are several reasons why BPA is not persuaded by Yakama’s argument. First, nowhere in the IERA are the words “electric utilities” used or even mentioned. The Act is intended to encourage energy resource development by Indian tribes, not the formation of tribal electric utilities. The Act expressly states that “the development of a vertically integrated energy industry on Indian reservations” is to “increase development of the substantial energy resources located on such Indian reservations.” 25 U.S.C. § 3503 (a). Second, assuming Yakama Power will purchase power from BPA, such a purchase is not within the meaning of the words “energy development” and “vertically integrated energy industry” as contemplated under the IERA. The Act’s legislative history expresses the intent for “energy development” on Indian reservations and to assist tribes through grants “to develop the industrial and administrative capacities to refine, develop, and market energy resources on the reservation.” H.R. Rep. No. 102-474 (VIII) at 92. “[I]t encourages tribes to assume more control over and responsibility for the use and management of their energy resources, and thereby helps to wean the tribes from their excessive dependency on the federal government.” *Id.* at 266. Third, the IERA refers to “the generation and transmission of electricity.” *Id.* at 94. Yakama would have BPA apply only the word “transmission” alone and in isolation to support its argument, while disregarding the term “generation.” BPA will not read the statute in this manner. The legislative history clearly states that:

[c]urrently, most Indian energy resources are extracted and immediately moved off the reservation for further refinement or preparation. Indian tribes receive little or no benefit from the processing and refinement of energy resources extracted from their lands. This section will not only provide grants to Indian tribes and Alaska Native organizations for the development, exploration and extraction of resources but it will also provide grants for the preparation, transportation and marketing of these resources.

*Id.* Contrary to Yakama’s position, the IERA applies when an Indian tribe is seeking to develop its own resources that exist on Indian reservations by making available grants to them. It does not apply, however, when an Indian tribe seeks to establish a tribal utility for the express purpose of purchasing power from BPA, or any other wholesale power provider, because that is not the development of an Indian energy resource on an Indian reservation. Further, because the IERA



does not apply in this case, it does not place a federal trust responsibility on BPA to mitigate the impact that the CRACs might have on the economic viability of Yakama Power.

BPA is certainly not without discretion to design rates to send appropriate pricing signals. Section 7(e) of the Northwest Power Act vests the Administrator with considerable discretion to, in rate schedules of general application, send appropriate pricing signals. Theoretically, in a particular case, the facts and section 7(e) might well warrant a rate design that is directed at tribal power consumption. Such a design might, for example, be calculated to encourage tribal consumption or certain patterns of tribal consumption. BPA is not persuaded in this case, however, that a rate based simply on Yakama's tribal status or the other facts presented by Yakama warrants a special rate tailored to it, *i.e.*, a rate not containing the three-tier CRAC adopted in this proceeding. The electric utility business is currently beset by market dislocations and unprecedented price swings. Whether, when, and how a sense of normalcy will return to the business is far from certain. What is very clear on the competitive landscape, however, is that this is a business, and it is a business for BPA that demands we look at the common good and achieve that while meeting our cost recovery objectives. While every customer has unique needs—some undoubtedly more pressing than others—BPA is not persuaded that the costs and burdens of individualized ratemakings of the sort advocated by Yakama are outweighed by the benefits.

### **Decision**

*The facts of this case do not warrant exercise of BPA's ratemaking discretion under section 7(e) of the Northwest Power Act to create a special tribal rate.*

### **Issue**

*Whether BPA is bound by the current contract with Yakama Power under general contract principles, a trust responsibility, and case law, to apply only the initial one-level CRAC.*

### **Parties' Positions**

Yakama makes several arguments. It argues that the contingent power sales contract is ambiguous and should therefore be construed as Yakama understood the terms of the agreement. CRITFC Brief, WP-02-B-CR/YA-02, at 37. Yakama claims BPA cannot use unanticipated economic shifts to increase the firm power rates established by the agreement. *Id.* It claims that it has detrimentally relied on BPA's assurances that the five-year May ROD rates would not change unless FERC remanded the case back to BPA, and hence, BPA is stopped from enforcing any increase in power rates against it. *Id.* at 39. Yakama also claims that controlling principles of federal Indian law, *i.e.*, the federal trust obligation, requires that the contract be construed as Yakama understood it at the time it signed. *Id.* at 42.

### **BPA Staff Position**

BPA stated in the Subscription ROD that the rate directives do not allow for the type of disparate rate treatment argued for by CRITFC and Yakama. *See* Subscription ROD, at 22. Even if such

treatment were legally sustainable, BPA believes that implementing a policy that exempts the tribal utilities from the application of the redesigned CRACs will result in an unfair burden on BPA's other Subscription Contract holders, including the Contingent Contracts. Burns and Berwager, WP-02-E-BPA-75, at 11.

### **Evaluation of Positions**

Yakama claims that in drafting the contract BPA used "ambiguous and loose language in the Agreement provisions with respect to BPA's ability to raise Yakama Power's rates." CRITFC Brief, WP-02-B-CR/YA-02, at 34. Yakama quotes section 2 [Definitions], which states:

Capitalized terms in this Agreement shall have the meanings defined below, in the exhibits or in context. All other capitalized terms and acronyms are defined in BPA's applicable Wholesale Power Rate Schedules, including the GRSPs or its successors.

*Id.* Yakama then quotes section 12(b) of the contract [Cost Recovery]:

BPA may adjust the rates for Contracted Power set forth in the applicable rate schedule during the term of this Agreement pursuant to the Cost Recovery Adjustment Clause in the 2002 GRSPs, or successor GRSPs.

*Id.* Yakama also quotes section 3(b) of the contract [Revisions to Priority Firm Power Rates]:

BPA agrees that the 5-year Rates available to Yakama Power consistent with this exhibit shall not be subject to revision during their respective terms, except for the application of a Cost Recovery Clause or a Targeted Adjustment Clause as provided in the PF applicable rates schedules and GRSPs and this Agreement.

*Id.* at 34-35. Yakama claims that it reasonably construed the contract as referring to the 2002 GRSPs (including the CRAC) in the May ROD submitted to FERC. *Id.* Yakama further states that it sought assurance from BPA regarding the application of power rates and CRAC parameters during the 2002-2006 rate period and relied on the representations made by BPA's representative [which were evidently tape recorded by the Yakama] that the rates and CRAC parameters adopted in the ROD would be fixed for the entire rate period unless FERC remanded the rates back to BPA. *Id.* at 35. Yakama notes that FERC has not done so. Yakama contends that section 16(d) of the contract [Entire Agreement] would not bar such evidence or the admissibility of the tape recordings to show Yakama's understanding at the time it signed the contract. *Id.* Yakama cites *Richardson v. Pension Plan of Bethlehem Steel Corp.*, 112 F.3d 982, 985 (9<sup>th</sup> Cir. 1997) and *Pierce County Hotel Employees and Restaurant Employees Health Trust v. Elks Lodge*, 827 F.2d 1324, 1327 (9<sup>th</sup> Cir. 1987) to support the proposition that if a term in a contract is ambiguous a court may look to earlier negotiations and extrinsic evidence to determine the intent of the parties. Yakama also argues the rule of *contra proferentem*, which provides that ambiguous contract provisions are to be construed against the drafter. *Id.* at 36 (citations omitted). Yakama concludes that the term "2002 GRSPs" refers to the 2002 GRSPs

submitted to FERC in BPA's 2002 rate case May ROD and that these GRSPs would not increase for five years. *Id.* at 36-37.

As a matter of contract interpretation, when the parties to a contract dispute the meaning of a contract, the court first considers its plain language. *Northrop Grumman Corp. v. Goldin*, 136 F.3d 1479, 1483 (Fed. Cir. 1998). Particular contractual provisions are read in the context of the entire agreement, and may not be construed so as to render portions meaningless. *Dalton v. Cessna Aircraft Co.*, 98 F.3d 1298, 1305 (Fed. Cir. 1996). An interpretation of a contract that makes any part "useless, inexplicable, inoperative, void, insignificant, meaningless, superfluous, or achieve[s] a weird and whimsical result" is not allowed. *Gould, Inc. v. United States*, 935 F.2d 1271, 1274 (Fed. Cir. 1991) (*quoting Arizona v. United States*, 216 Ct.Cl. 221, 575 F.2d 855, 863 (1978)). If a contract term is unambiguous, the court cannot assign it another meaning, no matter how reasonable it may appear. *See Triax Pacific, Inc. v. West*, 130 F.3d 1469, 1473 (Fed. Cir. 1997).

In applying the above rules of contract construction BPA does not believe the contract is ambiguous in its use of the term "2002 GRSPs." The contract is clear; the rates applied will be those in the 2002 GRSPs, as finally approved by FERC, including judicial review by the Ninth Circuit Court of Appeals. The basis for this is grounded in statute. BPA's rates do not become effective until FERC has granted final confirmation and approval of BPA's rates consistent with section 7(a)(2) of the Northwest Power Act. Section 9(e)(5) of the Act provides for exclusive judicial review in the Ninth Circuit for final agency actions, including final rate determinations. Moreover, throughout the contract it is clearly stated that the rates contained in the 2002 GRSPs are subject to change. Section 12(b) states:

BPA may adjust rates for Contract Power set forth in the applicable power rate schedule during the term of this Agreement pursuant to the Cost Recovery Adjustment Clause in the 2002 GRSPs, *or successor GRSPs*.

Emphasis added. In section 17 [Termination] the contract permits Yakama to terminate if:

(a) Any rates in WP-02 Final Rate Proposal, Administrator's Final Record of Decision are *remanded to BPA for reconsideration by FERC or the Ninth Circuit Court of Appeals*.

(b) *As a result of the remand*, the Administrator publishes a subsequent Final Record of Decision which, if confirmed, would result in *Yakama Power being subject to a higher average effective rate . . . .*

Emphasis added. Exhibit A, section 3(b) provides:

BPA agrees that the 5-Year Rates available to Yakama Power consistent with this exhibit shall not be subject to revision during their respective terms, *except for the application of a Cost Recovery Adjustment Clause or a Targeted Adjustment Charge as provided in the PF applicable rates schedules and GRSPs and this Agreement*.

Emphasis added. Exhibit A, section 6 provides, in pertinent part:

The parties shall update this exhibit to reflect necessary changes to new rate choices consistent with the *applicable future rate cases*. This shall be done by mutual agreement except as allowed in section 3 of this exhibit.

Emphasis added. Contrary to Yakama's contention, the ROD does not itself establish final rates, but rather, the ROD provides the evidentiary support for BPA's power rates that are subject to FERC review. The terms "2002 GRSPs" and "GRSPs" used in the contract indicate that the contract will incorporate the 2002 power rates as finally approved by FERC. Representations by BPA's representatives, memorialized by Yakama in tape recordings, are not inconsistent with this fact; however, no customer has a 100 percent guarantee that rates pending FERC review and approval will not change. This current rate case is not changing the base rates that will apply to power purchased under the contract, but rather, this case adjusts the level of the CRAC.

Contrary to Yakama's argument that a court may look to earlier negotiations and extrinsic evidence to determine the intent of the parties, the Supreme Court has ruled that the presence of an integration clause will bar extrinsic evidence. Absent evidence establishing that the writing, in fact, did not constitute a final expression, the general rule for determining integration is where the terms on the whole are complete and specific, the written contract "is presumed, in law, to express the final understanding of the parties." *Brawley v. United States*, 96 U.S. 168, 173-74 (1878). As the Supreme Court stated in *Brawley*, "[t]he written contract merged all previous negotiations, and is presumed, in law, to express the final understanding of the parties." 96 U.S., at 173. Thus, it is reasonable to conclude that a court will uphold the integration clause and bar introduction of tape recordings made by Yakama.

BPA's paramount rate obligation is to assure that the rates BPA establishes will recover BPA's costs. Section 7(a) of the Northwest Power Act obligates BPA to periodically review and revise rates to recover, in accordance with sound business principles, the cost associated with the acquisition, conservation, and transmission of electric power. 16 U.S.C. § 839e(a)(1). Under section 7(g) of the Act, BPA is required to equitably allocate to power rates all costs and benefits not otherwise allocated such as conservation, fish and wildlife measures, and uncontrollable events. 16 U.S.C. § 839e(g). Given the dramatic price volatility in the wholesale power market which began shortly after the May ROD was signed, and which continues today, and BPA's significantly greater load obligations, BPA has acted consistent with its statutory directive to ensure that the rates that will be in effect over the next five-year rate period recover all costs that BPA incurs. BPA is taking all necessary action to assure cost recovery by adjusting the CRAC, and it is doing so before the rates need to be in effect.

Under the futile acts doctrine, BPA is not required to wait for a remand by FERC to further review and revise BPA's rates. The law does not require the doing of a futile act, which in this case would have been to wait for a remand by FERC instead of BPA taking the proactive steps to revise the CRAC. See *Ohio v. Roberts*, 100 S.Ct. 2531, 2543 (1980); *Northern Heel Corp. v. Compo Industries, Inc.*, 851 F2d 456, 461 (1<sup>st</sup> Cir. 1988). BPA must defend its rates as meeting FERC's cost recovery standards for review of BPA rates. See 18 C.F.R. §§ 300.20 and 300.21(c). It would have been a futile act to await remand by FERC while losing the economy

and benefit of time to revise the rates to ensure cost recovery by the time performance under BPA's new power sale contracts begins.

Yakama argues that BPA cannot use unanticipated economic shifts to increase the firm power rates established by the agreement. CRITFC Brief, WP-02-B-CR/YA-02, at 37. By analogy, Yakama relies on the proposition that courts have refused to release the federal government from its contractual obligations on the grounds that there have been legislative or regulatory changes or even because of substantial shifts in the agency's implementation of existing law or regulation. *Id.* (citations omitted). Yakama argues that the provision on "uncontrollable force" in section 13 of the power sale contract "embodies the general principle that a contracting party is not relieved of its contractual obligations simply because it made a bad economic decision." *Id.* at 38. Yakama states BPA has demonstrated an impossibility of performance which would relieve BPA of its obligations to "honor the Agreement pursuant to the terms as the Yakama's understood them . . . ." *Id.*

This argument is unfounded. As explained above, the rate setting process for the 2002 power rates is not complete until FERC gives final approval. BPA is fulfilling its statutory obligation and its obligation under DOE RA 6120.2 to ensure that its rates will recover total costs. Contrary to Yakama's belief, the contract does not set the rates. The contract states plainly that BPA may adjust rates during the term of the contract pursuant to the CRAC in the 2002 GRSPs, or successor GRSPs. Yakama's reasoning that BPA is shifting unanticipated costs onto its contracting partner is flawed. The rates for which federal power is sold under contract by BPA must recover BPA's total costs, otherwise FERC will withhold approval and remand rates to BPA to ensure cost recovery. Thus, not until the rates are approved will BPA and its customers know the actual rates. Moreover, Yakama misunderstands the uncontrollable forces provision in the contract. BPA is not proposing to terminate the contract on the basis of impossibility of performance. To the contrary, BPA intends to fully meet its obligation under the contract to provide federal power and to charge rates as finally approved by FERC.

Yakama claims that it detrimentally relied on BPA's assurances that the five-year May ROD rates would not change unless FERC remanded the case back to BPA, and hence, BPA is estopped from enforcing any increase in power rates against Yakama. CRITFC Brief, WP-02-B-CR/YA-02, at 39. Yakama says it made a fundamental decision to devote considerable resources to creating and operating Yakama Power that was grounded on "an estimation that such a decision was economically feasible under the ROD submitted to FERC by Bonneville." *Id.* Yakama says it diverted resources would could have been devoted to housing, health, environment, employment or many other pressing tribal needs. *Id.*

Under the contract, BPA will not be estopped from applying rates that receive approval by FERC. *See Heckler v. Community Health Service of Crawford County Inc.*, 467 U.S. 51 (1984). It is well settled that the government may not be estopped on the same terms as a private litigant. *Watkins v. U.S. Army*, 875 F.2d 699, 706 (9<sup>th</sup> Cir. 1989). The party raising estoppel must establish affirmative misconduct and the government's wrongful act will cause serious injustice and the public's interest will suffer undue damage by imposition of the liability. *Id.* at 707. "[T]hose who deal with the Government are expected to know the law and may not rely on the conduct of Government agents contrary to law." *Heckler*, 467 U.S. at 63. If BPA's rates include

adjustments resulting from the Administrator's proposal to revise the CRAC, Yakama Power is obligated to pay them. As previously stated, the contract does not include a promise that the rates will not change. Moreover, Yakama Power signed a contingent contract which, among other things, allows it until September 30, 2005, to satisfy all contingencies. In particular, Yakama commented to BPA that entities forming a new utility needed flexibility "to accommodate the hurdles and timing considerations" in forming a utility and acquiring a distribution system. Power Subscription Strategy, Administrator's Supplemental ROD, at 4-5. Yakama's decision to sign the contract was based on its own economic feasibility analysis which identified a number of benefits. While Yakama may have believed that the rates would not change, the contract contains plain language stating the rates were subject to change. The contract does not include a promise that the rates will not change.

Yakama points out that BPA has stated that when customers sign contracts BPA is obligated to let its customers know what their rates will be before the rates case is concluded and contracts are signed. CRITFC Brief, WP-02-B-CR/YA-02, at 40. Yakama also criticizes BPA's decision to adjust the CRAC to meet higher than forecasted augmentation costs. *Id.* at 41. Yakama alleges that "Bonneville seems to be of the opinion that Yakama's .38 percent of total load may be enough to cause the economic downfall of the agency." *Id.*

BPA certainly recognizes the need customers have to know what rates will apply to power purchased under contract. Nonetheless, section 17 of the contract recognizes that circumstances may well change such as to require remand of, and changes in, the rates. This "proceeding is continuation of the WP-02 Rate Proceeding. . . . [C]onducted for the discrete purpose of resolving a cost recovery problem brought about by market price trends and load placement changes occurring since the record was closed in the first phase of the proceeding." Burns and Berwager, WP-02-E-BPA-62, at 3. Witness for the JCG testified that one of the reasons for BPA's additional augmentation costs is that new utilities are being formed and placing load on BPA. Brattebo, *et al.*, WP-02-E-JCG-03, at 44. Yakama alleges it totals only .38 percent of BPA's total load. BPA witnesses testified that BPA does not calculate its additional augmentation costs based on the class of type of contract because BPA views its augmentation obligation in the aggregate and augments to serve all of its Subscription contracts. Burns and Berwager, WP-02-E-BPA-75, at 13. Witnesses for the JCG assumed that if the Yakama load is 40 aMW and BPA imposes a 100 percent rate increase through the LB CRAC this fall, Yakama would be seeking to avoid paying as much as \$7.7 million annually. Brattebo, *et al.*, WP-02-E-JCG-03, at 45. This would result in BPA's other Subscription customers paying a disproportionate share of this expense at a time when their rates have already risen significantly above expectations. Burns and Berwager, WP-02-E-BPA-75, at 13; Brattebo, *et al.*, WP-02-E-JCG-03, at 45. WPAG states that "the current power and financial crisis being faced by BPA does not permit any BPA customer to be absolved from paying its fair share of the costs of augmenting the FBS by shifting those costs to other customers, regardless of when their BPA Subscription contract was signed." WPAG Brief, WP-02-B-WA-01, at 18-19.

Yakama contends that controlling principles of federal Indian law, *i.e.*, the federal trust obligation, requires that the contract be construed as Yakama understood it at the time Yakama signed. CRITFC Brief, WP-02-B-CR/YA-02, at 42. Yakama further argues that it should be exempt from any rate increases unless BPA demonstrates that there is absolutely no other

alternative through which BPA can spread anticipated cost increases. *Id.* at 42. Yakama claims the trust responsibility imposes a strict fiduciary standard on the conduct of executive agencies. Yakama relies on the following judicial decisions to support its position: *Seminole Nation v. United States*, 316 U.S. 286 (1942); *Navajo Tribe of Indians v. United States*, 364 F.2d 320 (Ct.Cl 1966). Yakama points to Department of Energy (DOE) and BPA tribal policies, the IERA, and the decision in *Morton v. Mancari*, 417 U.S. 535 (1974), to argue BPA should treat Yakama differently from other customers by creating a special rate category or construing the terms of the power sale contract as Yakama understood them to be at the time the contract was signed. *Id.* at 43.

BPA does not believe the cases and statute cited by Yakama stand for the proposition that BPA is under a specific trust responsibility to either create a special rate category or construe the power sales contract in the manner requested by Yakama. BPA agrees that 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. However, 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). In a footnote, Yakama contends that failure of BPA’s witnesses to “even discuss the financial risk posed to the tribal utility by the revised CRAC, or to consider the de minimis impact the .38 percent tribal load would have on other customers’ prices, or to consider the creation of a special rate category to deal with these issues clearly fails to meet the standards of a fiduciary that is truly attempting to fulfill its responsibilities.” CRITFC Brief, WP-02-B-CR/YA-02, at 42. Contrary to Yakama’s claim, BPA’s witnesses are under no duty to individually consider such impacts. An examination of BPA’s marketing statutes demonstrates that BPA is not under a specific trust responsibility for purposes of marketing federal power and the setting of wholesale power rates to Indian tribes.

BPA’s power marketing statutes lack any expression of intent by Congress to impose a fiduciary duty on BPA to treat Indian tribes differently, due to a specific trust responsibility, when selling federal power to customers. In particular, the pertinent power marketing language in section 5 of the Bonneville Project Act talks of sales to “public bodies and cooperatives” and makes no reference to Indian tribes. 16 U.S.C. § 832. The terms “public body” and “cooperative” are defined in section 3 and do not mention the words “Indian tribe(s).” Section 5 directs the Administrator to “negotiate and enter into contracts for the sale at wholesale of electric energy, either for resale or direct consumption, to public bodies and cooperatives and to private agencies and persons and for the disposition of electric energy to federal agencies.” Likewise, section 5 of the Northwest Power Act is similarly silent.

Court decisions support BPA's position regarding when the specific trust responsibility arises to a fiduciary duty owed by a federal agency. In *Morongo Band of Indians v. Federal Aviation Administration*, 161 F.3d 569 (9<sup>th</sup> Cir. 1998), 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 *Pawnee v. United States*, 830 F.2d 187, 191 (Fed. Cir. 1987), the court noted: "That there is such a general fiduciary relationship does not mean that any and every claim by [an Indian party] necessarily states a proper claim for breach of trust." And in *Skokomish Indian Tribe v. FERC*, 121 F.3d 1303 (9<sup>th</sup> Cir. 1997), the court noted that FERC exercises its trust responsibility in the context of the Federal Power Act and is not required to afford Indian tribes greater rights than they would otherwise have under the FPA and its implementing regulations. 121 F.3d at 1308-09. Similarly, when marketing power BPA exercises its trust responsibility in the context of its statutes and is not required to afford Indian tribes greater rights than they would otherwise have under BPA's statutes. Finally, as discussed *supra*, BPA does not believe that the IERA obligates BPA to fulfill a specific trust responsibility to Indian tribes by creating a special rate category that would be applicable to tribal utility customers. Nor will BPA read the *Morton v. Mancari* decision as broadly as suggested by Yakama in relation to the IERA, *i.e.*, BPA does not believe the creation of a special rate category based on a "political" preference to be given Yakama Power is reasonably and directly related to Congress' intent in passing the IERA. See CRITFC Brief, WP-02-B-CR/YA-02, at 48. Therefore, because the IERA does not apply in this case, it does not compel BPA to provide Yakama Power preferential rate treatment.

Yakama argues that BPA should take into account all of its arguments regarding trust responsibility, the IERA, and the canons of construction applicable to interpreting Indian treaty rights, to "use its discretionary power to exempt the Yakama from any subsequent rate increases. CRITFC Brief, WP-02-B-CR/YA-02, at 44. Yakama cites selected case law supporting the rule that when interpreting a treaty with an Indian tribe it should be interpreted in the tribe's favor: *McClahanahan v. Arizona State Tax Comm'n*, 411 U.S. 164, 174 (1973); *Carpenter v. Shaw*, 280 U.S. 363, 367 (1930); *Choctaw Nation v. Oklahoma*, 397 U.S. 620, 631 (1970); *United States v. Shoshone Tribe*, 304 U.S. 111, 116 (1938); *Jones v. Meehan*, 175 U.S. 1, 11 (1899); and *Worcester v. Georgia*, 31 U.S. (Pet.) 515, 551-554, 582 (1832).

BPA does not believe the canons of construction applicable to interpret Indian treaties apply in this case. First of all, Yakama and BPA executed a commercial contract, not a treaty. BPA's authority to offer this contract arises under section 5(b)(1) of the Northwest Power Act. Under this contract Yakama Power, acting by and for the Yakama Nation, expressly waived its sovereign immunity. Moreover, Indian nations have no immunity against the federal government. See *Turner v. United States*, 248 U.S. 354, 358 (1919); *U.S. v. Red Lake Band of Chippewa Indians*, 827 F.2d 380, 382 (8<sup>th</sup> Cir. 1987), *cert denied*. As such, the contract is subject to the same rules for the interpretation of contracts entered into between the United States and private persons. "Whenever the United States casts off its cloak of sovereign immunity to engage in a business type activity with a business minded purpose, it must be treated as a private



commercial contractor.” *California Sand and Gravel, Inc. v. U.S.*, 22 Cl.Ct. 19, 29 (1990), citing *Standard Oil Co. v. United States*, 267 U.S. 76, 79 (1925). The government contracts as does a private person, and its rights and duties are governed by the law applicable to contracts between private individuals. *California Sand and Gravel*, at 30. Because Yakama Power waived its sovereign immunity when it executed the contingent power sale contract it is, therefore, reasonable to conclude that Yakama Power must be considered a private person for this limited purpose and that the general law of contract interpretation applies. BPA believes that the plain meaning of the contract is that BPA has the authority to raise rates through application of the CRAC. In its brief Yakama concedes that “[t]he Contract here explicitly acknowledges that Bonneville has discretion over whether or not to raise rates.” CRITFC Brief, WP-02-B-CR/YA-02, at 44. BPA believes this is the appropriate and correct interpretation.

### **Decision**

*Neither general contract principles, a trust responsibility, nor case law, warrant BPA applying only the initial one-level CRAC to Yakama Power.*

## **2.10 Other Policy Issues**

### **Issue**

*Whether BPA should implement a Retail Rate Pilot Program offering incentives to participating utilities.*

### **Parties’ Positions**

WPAG states this is a “fruitful path.” WPAG Brief, WP-02-B-WA-01, at 16.

### **BPA Staff Position**

BPA proposed to introduce a Retail Rate Pilot Program offering incentives to customers. Burns and Berwager, WP-02-E–BPA-75, at 15-16.

### **Evaluation of Positions**

BPA witnesses testified that BPA would implement a special pilot program designed to further increase electric energy conservation. Burns and Berwager, WP-02-E–BPA-75, at 15. Such a program would encourage public utility customers to establish retail rate designs that reduce load on BPA. BPA will provide appropriate incentives or discounts to public utility customers that, through their retail rate schedule, establish a retail rate design during the coming rate period to encourage greater electric energy conservation and/or more efficient electricity usage and thereby reduce load on BPA. *Id.* at 15-16. WPAG supports this approach since it presents a clear price signal to the end user. WPAG Brief, WP-02-B-WA-01, at 16. “Since these are the rates the customer will confront when making electricity use decisions at the margin, this appears to be a much more fruitful approach. Encouraging stepped and time of use rates at the retail level will provide an enhanced price signal to the end user.” *Id.*

Public customers with non-load following service would be required to agree to contract modifications that assure any load reductions from this program result in lower load obligation on BPA. Burns and Berwager, WP-02-E-BPA-75, at 16. Qualifying retail rate designs could include: (1) an “increasing block” rate structure; (2) a time of day rate structure; or (3) some other rate design acceptable to BPA which provides an incentive structure that encourages electric energy conservation or demand reduction. *Id.*

**Decision**

*BPA will offer a Retail Rate Pilot Program with appropriate incentives for conservation and demand reductions. Program costs will be included in the LB CRAC determination.*

### **3.0 RISK ANALYSIS STUDY AND NO-SLICE RISK ANALYSIS**

#### **3.1 Introduction**

The objective of the Risk Analysis Study and No-Slice Risk Analysis 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 for the Risk Analysis Study and No-Slice Risk Analysis are quantified through the use of the Risk Analysis Model (RiskMod) and non-operational risks are quantified through the use of the Non-Operating Risk Model (NORM). The Risk Analysis Study and No-Slice Risk Analysis were performed using data that differed only in the amount of the Slice product being purchased. The Risk Analysis Study was performed using a sales forecast that included BPA's best estimate of the amount of the Slice product that would be purchased. The No-Slice Risk Analysis was performed using a sales forecast that reflected no sales of the Slice product.

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. The results from the Risk Analysis Study and No-Slice Risk Analysis are compared in the ToolKit Model to assess whether or not there is a cost-shift between the Slice purchasers and non-Slice purchasers. Other than revisions in data associated with the Slice product, the Risk Analysis Study and the No-Slice Risk Analysis used identical models and data. The Risk Analysis Study and the No-Slice Risk Analysis for the 2002 Supplemental Power Rate Proposal (Supplemental Proposal) were documented in Chapters 2 and 3 in the Study for the Supplemental Proposal, WP-02-E-BPA-67. For the 2002 Amended Power Rate Proposal (Amended Proposal), the Risk Analysis Study and the No-Slice Risk Analysis were documented in Chapters 2 and 3 in the 2002 Amended Power Rate Proposal Study, WP-02-E-BPA-58; Chapter 2 in the 2002 Amended Power Rate Proposal Study Documentation, Volume 1, WP-02-E-BPA-60; and Chapter 3 in the 2002 Amended Power Rate Proposal Study Documentation, Volume 2, WP-02-E-BPA-61.

#### **3.2 Changes Since the May 2000 Final Power Rate Proposal**

One of the notable changes since the 2002 Final Power Rate Proposal (May Proposal) was that BPA performed only the Risk Analysis Study in the May Proposal, but performed both the Risk Analysis Study and No-Slice Risk Analysis in the Amended and Supplemental Proposals. The reason for this change was due to a change in how the Cost-Shift Analysis was performed for the May Proposal (*see* 2002 Final Power Rate Proposal, Wholesale Power Rate Development Study Documentation, Volume 2, WP-02-FS-BPA-05B, at 140-164) and for the Supplemental and Amended Proposals (*see* 2002 Supplemental Power Rate Proposal Study, WP-02-E-BPA-67, at 5-31 to 5-37 and 2002 Amended Power Rate Proposal Study, WP-02-E-BPA-58, at 4-11 to 4-15). The Study for the Final Supplemental Proposal does not include a No-Slice Risk Analysis because the question of whether or not the Slice product caused any shifts in costs or risks to Non-Slice customers or taxpayers was answered in the negative by the analyses in the Amended and Supplemental Proposals. *See* Section 4.3.1 *infra*.

BPA made several changes to the Risk Analysis Study and the No-Slice Risk Analysis since the May Proposal. The following modeling and data changes were made to the RiskMod for the Amended Proposal: (1) including the purchase of 2,000 average megawatts (aMW) of Slice, including the Slice Revenue Requirement<sup>1</sup>; (2) removing the adjustments to the electricity prices estimated by AURORA during the months of April through June; (3) revising the Non-Treaty Storage algorithm to incorporate updated storage and withdrawal constraints and fish operations; (4) including load swing risk due to weather and economic conditions for the Pre-Subscription contracts; (5) including variability in the revenue from the load variance charge as loads vary; (6) using one set of spot market electricity prices from AURORA, instead of three sets of prices, for the 13 fish and wildlife alternatives; (7) revising the DSI load forecast and the Public Utility Sales Forecast; (8) including the amount and cost of actual System Augmentation purchases; (9) updating monthly heavy load hour (HLH) and light load hour (LLH) spot market prices from AURORA; and (10) revising natural gas price and load volatility estimates that were used when simulating natural gas price and load risk for use in AURORA. *See Conger, et al., WP-02-E-BPA-63, at 2-7.*

The following modeling changes were made to NORM for the Amended Proposal: (1) revising output from the NORM for Fiscal Years (FY) 2002-2006 to account for the impact of Slice; and (2) re-characterizing the Fish and Wildlife Funding Memorandum of Agreement (MOA) carry-forward fund risk to a possible additional expenditure, rather than a possible reallocation, in the NORM for FY 2001. *See Conger, et al., WP-02-E-BPA-63, at 7-8.*

The Amended Proposal contained the following changes in loads and resources: (1) including actual System Augmentation purchases of 917 aMW (5-year average) at a cost of \$242.9 million/year as a resource; (2) revising the Public Utility Sales Forecast methodology and increasing the forecasted Public Utility Sales for the 5-year rate period by 1,472 aMW for the Risk Analysis Study (with 2,000 aMW of Slice) and 1,565 aMW for the No-Slice Risk Analysis; and (3) increasing the DSI sales forecast by 46 aMW. *See Conger, et al., WP-02-E-BPA-63, at 9-10, 15.*<sup>1</sup>

The following changes were made to the Natural Gas Price Forecast: (1) revising the Natural Gas Price Forecast to reflect the degree of price response observed under tight supply/demand conditions and more recent New York Mercantile Exchange (NYMEX) futures contract prices; and (2) revising the natural gas price projections from a long-term structural trend to an ongoing cyclical pattern. The AURORA model for the Amended Proposal changed as follows: (1) updating the version of AURORA from Version 3.2.8 to Version 5.1.13; (2) updating the forecasted natural gas prices; (3) updating the forecasted loads; (4) updating the load growth rates; and (5) revising the size and prices of some of the curtailment blocks in AURORA. *See Conger, et al., WP-02-E-BPA-63, at 11-15.*

The following modeling and data changes were made to RiskMod for the Supplemental Proposal: (1) revising computations so that the rate case parties bear the risk of the amount and price of System Augmentation purchases, including the cost of serving the load growth and load variability of the Full and Partial Requirement customers; (2) calculating the net revenue impact of two load levels (0 and 1,500 aMW of load reduction) and three electricity price levels

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<sup>1</sup> Final studies will reflect a reduction in Slice load to 1,600 aMW.

(\$315/megawatthour (MWh), \$210/MWh, and \$140/MWh in FY 2002); (3) removing the computation of the cost of the Inventory Solution from the Slice Revenue Requirement in RiskMod; (4) capping the 4(h)(10)(C) credits at the amount of the annual Treasury Payments for FY 2002-2006; (5) revising the expected Fish Cost Contingency Fund (FCCF) reserve at the start of FY 2002 to a point estimate of \$167 million; (6) revising the expected Non-Treaty Storage level at the start of FY 2002 from 2,858 MW/months to 1,000 MW/months; (7) revising the amount and cost of actual System Augmentation purchases to 1,048 aMW (five-year average) at a cost of \$280.5 million/year; and (8) developing the Forward Market Price Simulator, which simulated electricity prices for FY 2002 and 2003 using forward market electricity prices and the electricity price volatility reflected in option premiums. *See Conger, et al.*, WP-02-E-BPA-71, at 3-8.

No issues regarding the Risk Analysis Study and No-Slice Risk Analysis were raised in any of the initial or exceptions briefs of the rate case parties. However, the following related issue was raised earlier by a rate case party and addressed by BPA in its rebuttal testimony.

### **Issue**

*Whether, when refilling storage, BPA should consider the economic cost and timing of refill purchases, rather than refilling storage based solely on engineering or fish concerns.*

### **Parties' Positions**

The Industrial Customers of Northwest Utilities (ICNU) asserts that, rather than refilling storage based solely on engineering or fish concerns, BPA should consider the economic cost of refill and the timing of refill purchases when achieving this goal. *See Wolverton*, WP-02-E-IN-02, at 9-10.

### **BPA Staff Position**

BPA's testimony (*see Conger, et al.*, WP-02-E-BPA-71, at 5, lines 20-24) cited in ICNU's testimony (*see Wolverton*, WP-02-E-IN-02, at 9, lines 15-17) only addressed a revision in RiskMod for the projected Non-Treaty Storage level on October 1, 2001. Since ICNU only makes reference to storage, it is unclear whether or not its testimony is in regard to Non-Treaty Storage or storage in general. Operational rules, constraints, treaties, and contracts govern storage operations for the FCRPS, which includes Columbia River Treaty Storage. Determining how to refill storage for the FCRPS in the most economical manner is very complex. Storage operations for the FCRPS are modeled in the rate case in the Hydro Regulation Study. *See 2002 Final Power Rate Proposal, Loads and Resources Study Documentation*, WP-02-FS-BPA-01A, at 14-29. In contrast, the use of Non-Treaty Storage by BPA is more discretionary, depending on circumstances. Given the projected low streamflow and reservoir conditions for FY 2001 and high market prices in FY 2002, it seems likely that BPA will deviate from its typical Non-Treaty Storage operations in FY 2002. Accordingly, BPA proposes to reflect Non-Treaty Storage operations that are more indicative of FY 2002 conditions. *See Conger, et al.*, WP-02-E-BPA-76, at 2-3.

## **Evaluation of Positions**

BPA agrees that it is reasonable to consider the economic cost of refilling storage and the timing of refill purchases in its Non-Treaty Storage operations for FY 2002.

### **Decision**

*BPA will consider the economic cost of refilling storage and the timing of refill purchases in its Non-Treaty Storage operations for FY 2002.*

## 4.0 RISK MITIGATION

### 4.1 Introduction

BPA's 2002 Final Power Rate Proposal (May Proposal) included a robust risk mitigation package, which considered a larger number and wider variety of risks than those in previous rate cases. It addressed revised guidelines for both rate design and risk mitigation. These included:

- Fish and Wildlife Funding Principles (Principles) (including the goal of strict adherence to the 88 percent Treasury Payment Probability (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 Cost Recovery Adjustment Clause (CRAC) and a Dividend Distribution Clause (DDC) in the rate design to deal with potential revenue shortfall and over-recovery.

*See* 2002 Final Power Rate Proposal, Administrator's Record of Decision (May ROD), WP-02-A-02, at 7-1 to 7-2; Revenue Requirement Study, WP-02-FS-BPA-02, Chapter 2; and Volume 1, Documentation to Revenue Requirement Study, WP-02-FS-BPA-02A, Chapter 12.

Since the publication of the May Proposal, significant changes in West Coast power markets and unanticipated system augmentation have required BPA to reassess its risk profile and develop an even more robust mitigation package to ensure cost recovery. In August 2000, BPA reviewed events during the summer months that indicated that power markets on the West Coast had become more volatile than previously anticipated. BPA concluded that, in light of the unprecedented price spikes during the summer months, BPA's cost-based rates for the Fiscal Years (FY) 2002-2006 would be far more attractive to prospective customers than market alternatives. Accordingly, the customers could be expected to purchase significantly more power than originally anticipated. *See supra*, Section 2.1.

BPA recognized that this combination of an unanticipated increase in loads with higher and more uncertain market prices greatly diminished the probability that the base rates developed for the May Proposal would fully recover generation function costs. Absent a change to proposed rates, the increased load obligations that BPA must meet through power purchases made in a market characterized by volatile and escalating prices would decrease TPP to an unacceptable level. Supplemental Proposal Study Documentation, WP-02-E-BPA-69, at 5-3.

BPA determined that an amendment to its May Proposal would be needed to keep TPP in the 80-88 percent range called for in Principles Nos. 3 and 4 and to ensure the agency's financial solvency. A decision was made to avoid any revisions to the Subscription Strategy and minimize the revisions to the 2002 rate proposal. *See supra*, Section 2.3. The scope of BPA's 2002 Amended Power Rate Proposal (Amended Proposal) was limited to dealing with the uncertainties surrounding the costs of augmentation, primarily through a modification of the

CRAC design. The Amended Proposal does not involve development of a new revenue requirement or a recalculation of base rates. Burns and Berwager, WP-02-E-BPA-70, at 6-7. Building upon the design changes in the Amended Proposal, BPA subsequently filed its Supplemental Proposal in February 2001 to address three major changes from the Amended Proposal: a substantially lower forecast of starting reserves for the FY 2002-2006 rate period (expected value of \$308.7 million), significantly higher market prices for power, and a Partial Stipulation and Settlement Agreement developed through discussions with BPA staff and many of the rate case parties. *Id.* at 2. The Final Supplemental Study includes updated starting reserves with an expected value of \$429 million for the power function.

At the time the May Proposal was issued, BPA was assuming both lower levels of augmentation purchases and lower market prices for power than emerged in the late summer and fall of 2000. Given the much less severe risk profile BPA was using at that time, a single (financial-based) CRAC was sufficient to ensure an 88 percent TPP. More recent forecasts of load placement, market prices, and FY 2002 starting reserves have altered the magnitude and distribution of financial risks in a way that necessitates more stringent risk mitigation measures.

The Supplemental Proposal (like the Amended Proposal before it) contains the same risk mitigation tools as the May Proposal – Planned Net Revenues for Risk (PNRR), Fish Cost Contingency Fund (FCCF) credits, and starting reserves. (*See* May ROD, WP-02-A-02, at 7-2.) The FCCF credits and starting reserves have been updated to reflect more current forecasts. The May Proposal included a single CRAC, while the Supplemental Proposal includes a three-component CRAC mechanism, designed to maintain the TPP level within the 80-88 percent TPP range called for in the Principles. Lefler, *et al.*, WP-02-E-BPA-73, at 5-6. The three components are the Load-Based (LB) CRAC, the Financial-Based (FB) CRAC, and the Safety-Net (SN) CRAC, which are described as follows:

- The LB CRAC is designed to cover the net cost of augmenting BPA’s system to meet the additional 1,518 aMW of load placement by what is, in effect, a variable price mechanism. Because BPA will be acquiring this additional power in a highly volatile market, it is not possible to accurately forecast the cost of purchasing this power over the entire five-year rate period. Accordingly, the LB CRAC has been designed to be responsive to changes in the market price of power. BPA will establish a preliminary LB CRAC amount for each year of the rate period, FY 2002-2006. The amount will be based on the current forecast of forward market prices for each year, shaped, and the amount by which loads contracted for exceed BPA resources, less purchases for augmentation prior to August 1, 2000. Second, the preliminary LB CRAC amount will be adjusted for each six-month period of the rate period, beginning October 2001. Finally, about 90 days after the end of each six-month period, BPA will true-up the LB CRAC based on actual augmentation purchases during the period. Supplemental Proposal Study Documentation, WP-02-E-BPA-69, at 5-11 and 5-12. For purposes of calculating the LB CRAC, BPA will assume Conservation Augmentation costs are capitalized.
- The FB CRAC is structured in substantially the same way as the CRAC in the May Proposal—it triggers when a forecast of Accumulated Net Revenues (ANR) falls below a threshold value for a particular year. It can generate additional cash in that year, with the



amount limited to a pre-determined amount in all but the first year. The FB CRAC differs from the one proposed in May in two significant ways. First, the annual cap on new revenue collection for FY 2002 was removed: in FY 2002 the FB CRAC can collect whatever amount of additional revenues would have been needed to raise ending FY 2001 ANR to the reserves equivalent of the \$300 million threshold value for that year. The annual thresholds and caps for the remainder of the rate period, FY 2003-2006, remain the same. Thresholds are set at the ANR equivalents of \$300 million in reserves for FY 2001 and 2002, and \$500 million for FY 2003-2005. Annual caps on revenue collection, after the first year, are \$135 million for FY 2003, \$150 million for FY 2004-2005, and \$175 million for FY 2006. Second, the timing of the collection of the FB CRAC has changed. In the May Proposal, it was proposed that determination of whether the FB CRAC trigger is reached would be based on audited actual financial data available in January, and that collection would be made over a 12-month period beginning in April. By contrast, the Amended Proposal called for collecting the full amount in the four months between March and June. In this Supplemental Proposal, the FB CRAC reverts to the 12-month collection period. However, collection would begin in October following an initial determination made in August after the Third Quarter Review. *Id.* at 5-13.

- The SN CRAC is a provision designed to raise rates if a payment to Treasury or other creditor has been missed, or there is a 50 percent probability that such a payment may be missed in the then-current year. Triggering of the SN CRAC starts an expedited section 7(i) proceeding, in which changes to the amount, duration, and timing parameters of FB CRAC can be made, taking into account conditions prevailing at the time. Because these changes cannot be known at this time, and because SN CRAC will not affect the calculation of the TPP, SN CRAC is not modeled in ToolKit. *Id.* at 5-13.

The DDC was also modified from its design in the May Proposal to reflect the changes outlined in the Partial Stipulation and Settlement Agreement. The DDC in the May Proposal provided for dividends to be distributed to power customers and potentially other stakeholders if certain conditions were met. If Audited Accumulated Net Revenues (AANR) reached the reserve equivalent of \$250 million for the end of any year, FY 2001-2005, BPA would determine if it could distribute the amount exceeding the threshold and still maintain an 88 percent TPP. If so, the first \$15 million would be allocated to qualifying power customers participating in the Conservation and Renewables Discount (C&R Discount). The remainder would be distributed to customers, and potentially other stakeholders, based on allocation criteria decided upon in a separate public consultation process.

BPA's Supplemental Proposal includes three modifications to the DDC. First, if a specific DDC threshold is met, all of the DDC amount (above the \$15 million already committed to the C&R Discount) will automatically be distributed to customers and will no longer be discretionary on the part of the Administrator. Distributions will no longer be divided and allocated based on decisions in a later public process. Second, the thresholds were raised. There is no DDC available in FY 2002 (based on ending FY 2001 ANR), and the thresholds will be fixed at the ANR equivalent of \$1.7 billion in reserves for the second year (based on ending FY 2002 ANR), \$1.5 billion for the third year (based on ending FY 2003 ANR), and \$1.2 billion for each of the last two years (based on ending FY 2004 and 2005 ANR). These thresholds will be fixed, except

that they will be adjusted in the event that BPA has certain unspent fish and wildlife funds. Finally, as part of the Partial Stipulation and Settlement Agreement, BPA is proposing that the financial portion of the Residential Exchange Program Settlement Benefits be eligible for a portion of the DDC. Burns and Berwager, WP-02-E-BPA-70, at 10-11.

Because the design of the LB CRAC calls for adjustments based on actual levels of augmentation and actual market prices, this Supplemental Proposal includes a range of TPPs rather than a point estimate. The ToolKit model, which had been modified to model the three-component CRAC and revised DDC, was run a total of six times to demonstrate the impacts of different levels of market price and load reduction on the amount of revenues to be collected under the LB CRAC. The February 2001 Supplemental Proposal included an additional six runs to demonstrate that the Supplemental Proposal does not shift costs to non-Slice customers. See Supplemental Proposal Study Documentation, WP-02-E-BPA-69, at 5-16 and 5-17. The six runs in the Final Supplemental Study explored the following combinations of modeling assumptions:

$$3 \text{ sets of market prices} \times 2 \text{ load reduction levels} \times 1 \text{ Slice sales levels} = 6 \text{ ToolKit Alternatives}$$

where:

market price levels for FY 2002 are set at \$100, \$148, and \$225/megawatthour (MWh), load reduction level is either 0 or 750 aMW, and the Slice sales levels are at 1,600 aMW

The TPPs associated with the six runs that assume BPA's total Slice sales were 1,600 aMW have TPPs that range from 81.6 to 88.3 percent. See Final Supplemental Proposal Study Documentation, WP-02-FS-BPA-10.

Although it is obvious that a dramatic change in market price expectations has occurred since the May Proposal was drafted, BPA has not abandoned its goal of 88 percent. While the Supplemental Proposal TPP values fall somewhere in the middle of the 80-88 percent range, BPA is exploring non-rate design options that should move BPA closer to the 88 percent TPP goal. Moreover, while the SN CRAC is not likely to head off a first deferral, it would have a strong chance of eliminating subsequent deferrals during the rate period. This would not change TPP, but by reducing or eliminating multiple deferrals, the SN CRAC would additionally reduce the likelihood of ending the rate period with low reserves. Lefler, *et al.*, WP-02-E-BPA-77, at 28-31.

Thus, this Supplemental Proposal, with a three-component CRAC in addition to the PNRR in the May Proposal, FCCF, and starting reserves, results in a risk mitigation package even more robust than that in the May Proposal.

## 4.2 Starting Reserves

### Issue

*Whether starting reserves need to be recalculated for the Final Supplemental Proposal to account for Fish and Wildlife Memorandum of Agreement (MOA) carry-forward funds.*

### Parties' Positions

Columbia River Inter-Tribal Fish Commission (CRITFC)/Confederated Tribes and Bands of the Yakama Nation (Yakama) argue in their initial brief that BPA's calculation of starting reserves for the FY 2002-2006 rate period overstates the available funds because the reserves contain \$227 million in funds guaranteed for fish and wildlife measures under the Fish and Wildlife Memorandum of Agreement (MOA). They state "CRITFC and Yakama have testified repeatedly about this illegal use of the MOA funds in the rate case and Bonneville has continued to include the funds in reserves for other uses. This is an illegal use of the funds under the MOA. Bonneville must recalculate its starting reserves after removing these MOA funds and adjust its TPP accordingly." CRITFC/Yakama Brief, WP-02-B-CR/YA-02, at 24.

Though worded somewhat differently, this argument was also presented by CRITFC/Yakama in their February 2000 initial brief. WP-02-B-CR/YA-01, at 38. There they recommended that BPA reduce its starting reserve by \$227 million "to avoid double-counting the unexpended MOA funds." *Id.* at 40. CRITFC/Yakama further argued 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 at the same time 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.

### BPA Staff 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

This issue was raised in CRITFC/Yakama's February 2000 Brief and was dealt with in the May ROD, WP-02-A-02, at 7-41 through 7-44. CRITFC/Yakama have offered no new arguments, except to now describe in their initial brief as "illegal" what they previously described as "double-counting." They have not shown how BPA's calculation might be an "illegal use of funds," given that it is consistent with the MOA. CRITFC/Yakama raised no new evidence.

### Decision

*BPA has appropriately included the MOA carryforward funds balance in the starting reserves balance for FY 2002 and is neither double-counting nor illegally using these funds. Starting reserves will not be adjusted to reflect a change in the calculation of these funds.*

### **4.3 Cost Recovery Adjustment Clauses**

#### **4.3.1 Load-Based Cost Recovery Adjustment Clause**

##### **Issue 1**

*Whether BPA's proposed use of revenues to determine the LB CRAC percent is fundamentally inconsistent with the basic principles for allocating costs to Slice purchasers as set forth in the Block and Slice Power Sales Agreements (Block/Slice Contracts).*

##### **Parties' Positions**

Public Generating Pool (PGP) and Pacific Northwest Generating Cooperative (PNGC) assert that BPA's revenue-based method for allocating augmentation costs to Slice is fundamentally inconsistent with the basic principles for allocating costs to Slice purchasers as set forth in the Block/Slice Contracts. PGP/PNGC Brief, WP-02-B-PG/PN-01, at 9. PGP and PNGC argue that unless Slice purchasers agree to alter their contracts, BPA should not switch from the resource-based method of allocating the costs. *Id.* at 9-10.

##### **BPA Staff Position**

BPA agrees that its proposal for use of a revenue-based method for allocating inventory augmentation costs to the Slice product is different from the resource-based method for allocating costs associated with the Slice base rate adopted in the May ROD and as set forth in the Block/Slice Contracts. Burns and Berwager, WP-02-E-BPA-70, at 12. The method for determining the LB CRAC percent contained in the General Rate Schedule and Provisions (GRSPs) (2002 Supplemental Power Rate Proposal Appendix, WP-02-E-BPA-68, at 2-10) is a revenue-based approach, as opposed to a resource-based approach. BPA stated in its Supplemental testimony that this approach is appropriate because BPA's augmentation cost problem is fundamentally one of collecting sufficient revenues to recover costs. Lefler, *et al.*, WP-02-E-BPA-73, at 14. As a result, BPA developed an approach that collects the amount of additional revenues as a percentage of the revenues collected. *Id.* The revenues to cover inventory augmentation costs is apportioned to individual purchasers on the basis of their individual contribution to revenues. By using this method, all of the calculations for the LB CRAC are in terms of dollars, which translate directly into a new rate with the LB CRAC applied. *Id.*

The LB CRAC mechanism BPA is proposing to establish is completely separate from, and is not constrained by, the cost allocation methodology contained in the Block/Slice Contracts. Furthermore, BPA and the Slice purchasers mutually agreed to add section 18 in the Block/Slice Contract to allow for amendments to the Block/Slice Contract to incorporate changes resulting from decisions in the Administrator's Final Supplemental ROD.

## **Evaluation of Positions**

PGP and PNGC argue that BPA should not use a revenue-based method for allocating inventory augmentation costs to the Slice product because this method is fundamentally inconsistent with the basic principles for allocating costs to Slice purchasers as set forth in the Block/Slice Contracts. PGP/PNGC Brief, WP-02-B-PG/PN-01, at 9. BPA understands that this method is different from the resource-based allocation method reflected in the Block/Slice Contracts for all costs included in the Slice Revenue Requirement. Burns and Berwager, WP-02-E-BPA-70, at 12. BPA determined that the revenue-based method for allocating inventory augmentation costs was an appropriate and equitable method to distribute costs between power products subject to the LB CRAC, not just between Slice and non-Slice customers. Lefler, *et al.*, WP-02-E-BPA-73, at 14. The revenue basis is a different way to allocate augmentation costs to Slice purchasers as compared to the design contained in the May Proposal. Shifting to a revenue basis is appropriate now given the change in the design and application of the LB CRAC to Slice purchasers. Under the May and Amended Proposals, Slice purchasers were exempt from the application of any of the CRACs. In the both the May and Amended Proposals, the CRACs were allocated to customers on a revenue basis; that is, a single rate increase percentage was developed to be applied to all rates subject to the CRAC. May ROD, WP-02-A-02, Appendix 2, at 87-88; Amended Proposal Study, WP-02-E-BPA-59, Appendix, at 6-7. However, with the development of the Supplemental Proposal and the application of the LB CRAC to Slice, BPA appropriately, and consistently with prior practice, applied the LB CRAC to Slice purchasers and non-Slice customers on a revenue basis, that is, again BPA sought to develop a single rate increase percentage that would be applied to all rates subject to the LB CRAC.

Additionally, as noted by BPA, the LB CRAC is designed to address a cost recovery problem. Lefler, *et al.*, WP-02-E-BPA-73, at 6. By allocating LB CRAC costs on a revenue basis, all customers who purchase power products face the same rate increase percentage in order for BPA to collect sufficient revenues to recover costs associated with augmenting the system. Therefore, by using a revenue basis, BPA ensures that the allocation of such costs is equitable.

PGP and PNGC are concerned that, if BPA uses a revenue basis to allocate the LB CRAC, this basis will be inconsistent with the Block/Slice Contract. This argument is misplaced. As noted, the application of the LB CRAC on a revenue basis is consistent with the manner in which CRACs have been applied since the May Proposal. Further, the design of the LB CRAC is a rate design issue that is not addressed in any way by the Block/Slice Contract. There is nothing in the Block/Slice Contract that constrains BPA's rate methodology used to design and implement the LB CRAC. Even if the Block/Slice Contract did contain some provisions addressing the design of the LB CRAC, BPA has the right, through section 18 in its executed Block/Slice Contracts, to amend the contract to incorporate changes from decisions in the Final Supplemental ROD.

## **Decision**

*BPA's proposed use of revenues to determine the LB CRAC percent, while different from the principles for allocating other costs to Slice purchasers, is an appropriate and equitable method.*

## **Issue 2**

*Whether BPA's proposed use of revenues to determine the LB CRAC percent represents a sharp departure from the Administrator's Slice principle of no cost shift or risk shift among customers and from what BPA agreed to in executed Block/Slice Contracts.*

### **Parties' Positions**

PGP and PNGC argue that BPA's proposal to determine the LB CRAC percent using a revenue-based allocation method is contrary to the Administrator's Slice principle of no cost or risk shift among customers and from what BPA has agreed to in executed Block/Slice Contracts. PGP/PNGC Brief, WP-02-B-PG/PN-01, at 10. Furthermore, PGP and PNGC point to a data response, incorporated in the Joint Customer Group's (JCG) rebuttal testimony (Brattebo, *et al.*, WP-02-E-JCG-03, Attachment A), that PGP and PNGC believe demonstrates cost shifts associated with different allocation methodologies. PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01, at 23.

The DSIs argue that BPA should adhere to its position to allocate inventory augmentation costs between Slice and non-Slice products on the basis of revenues. DSIs Brief, WP-02-B-DS/AL-02, at 41. The DSIs assert that an allocation of augmentation costs based on firm kilowatthours instead of revenues would reduce the Slice purchasers' share of augmentation far below the Slice purchasers' respective percentage shares of generation output from the federal system, as the firm kilowatthour sales basis does not account for the total energy available under the Slice product. *Id.* at 42. The Slice product includes secondary energy in-kind, as it is a bundled product that includes the right to both firm power and surplus power. *Id.*

The Northwest Requirements Utilities (NRU) agrees with BPA's proposal to determine the LB CRAC percent using a revenue-based allocation method. NRU asserts that BPA's analysis has shown that a load-based assignment of augmentation costs does, in some scenarios, create a cost-shift to full requirements customers. NRU Brief, WP-02-B-NI-03, at 10. NRU also asserts that, while other customer groups have proposed other cost allocation methods, none have been submitted with sufficient detail for the parties to respond to in this rate proceeding. *Id.* NRU agrees with the position taken by the DSIs in their rebuttal testimony on this issue at Schoenbeck, *et al.*, WP-02-E-DS/AL-03, at 12. *Id.* Canby agrees that use of revenues to determine the LB CRAC percent for Slice purchase is an appropriate and equitable method. Canby Ex. Brief, WP-02-R-CA-2, at 32.

### **BPA Staff Position**

BPA believes that using a revenue basis to allocate the LB CRAC does not create a cost shift among customers. The PGP and PNGC point to evidence incorporated in the JCG Supplemental rebuttal testimony (Brattebo, *et al.*, WP-02-E-JCG-03, Attachment A) that PGP and PNGC believe demonstrates costs shifts associated with different allocation methodologies. PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01, at 23. It is BPA's position that this evidence does not prove that cost shifts to Slice purchasers result due to use of a revenue-based cost allocation

method. In addition, this evidence does not prove that using a resource-based cost allocation method is the most equitable way to allocate inventory augmentation costs.

One of the fundamental principles BPA has adhered to with the decision to offer Slice is that the Slice product would create no risk or cost shifts to other customers. May ROD, WP-02-A-02, at 16-2. This was the first of five principles that BPA required a Slice product proposal to meet before it would be acceptable to BPA and the region. Specifically, BPA has stated that it did not want the decision to offer a Slice product to increase the costs or risks to its customers who purchase other products from BPA. Power Subscription Strategy, Administrator's Record of Decision (Subscription ROD), at 99. BPA reaffirmed this and clarified that offering the Slice product should not cause any shift of costs or risks from the Slice purchasers to other customers or to taxpayers in its Amended Proposal. Procter, *et al.*, WP-02-E-BPA-64, at 12. Furthermore, BPA stated that it did not rule out the possibility of the use of any mechanism to make adjustments to the Slice product if they are needed to address a cost or risk shift if it occurs. Subscription ROD, at 99. An example of such an adjustment to the Slice product is the application of the LB CRAC percent to the Slice Rate, in order to cover BPA's increased inventory augmentation costs, which otherwise would not have been recovered through the Slice Rate. Supplemental Proposal Study, WP-02-E-BPA-67, at 5-16. The revenue-based approach to allocating increased inventory augmentation costs is equitable to all purchasers of products subject to the LB CRAC, not just between Slice purchasers and non-Slice customers, and does not create a cost shift, because the increment in revenues needed to cover inventory augmentation costs is apportioned to individual purchasers on the basis of their individual contribution to revenues. Lefler, *et al.*, WP-02-E-BPA-73, at 14.

As detailed in the Supplemental Proposal Study, WP-02-E-BPA-67, at 3-1 to 3-5, BPA performed a cost shift analysis of its proposal to assess whether there was a cost shift from Slice purchasers to non-Slice customers. This study allocated the LB CRAC on a revenue basis and concluded that there were no such cost shifts resulting from offering the Slice product.

Issue 1, *supra*, addressed whether the use of a revenue-based approach to determining the LB CRAC percent contradicts the executed Block/Slice Contracts. It is BPA's position that nothing in the Block/Slice Contracts obligates BPA to a resource-based approach to determining the LB CRAC percent. BPA's proposed adoption of a revenue-based approach to determining the LB CRAC percent does not contradict the executed Block/Slice Contracts.

### **Evaluation of Positions**

Neither PGP, PNGC, nor the JCG provided direct testimony to support the assertion by PGP and PNGC that BPA's use of revenue-based cost allocation method to determine the LB CRAC results in a cost shift to Slice purchasers. The JCG raised this issue in its rebuttal testimony but did not advocate a particular method of allocation, or provide evidence that the revenue-based cost allocation method results in a cost shift to Slice purchasers. Brattebo, *et al.*, WP-02-E-JCG-03, at 45. The JCG did offer a resource-based allocation for BPA's consideration, but again, the JCG neither advocated its adoption nor provided evidence about any cost shift it might cause or avoid. *Id.* The JCG included as an attachment, a BPA data response (DS-BPA: No. 364) that indicates that allocation of inventory augmentation costs on a

revenue-basis assigns a larger fraction of such costs to Slice purchasers as a group, than does allocation by MW, but does not claim that this larger share is disproportionate. *Id.* The JCG suggest a resource-based allocation approach for BPA's consideration, but do not advocate its adoption, and do not present any evidence or conclusions regarding its impact on causing or avoiding cost shifts. *Id.* PGP and PNGC's brief does not specifically identify the source of the cost shift nor provide any evidence supporting this contention. Further, the evidence on the record cited by the PGP and PNGC does not support their assertion that a cost shift to Slice purchasers results from using a revenue-based cost allocation method. PGP/PNGC Brief, WP-02-B-PG/PN-01, at 10. In fact, BPA's extrapolation of the data referred to in the JCG rebuttal testimony (Brattebo, *et al.*, WP-02-E-JCG-03, Attachment A) shows that a revenue-based cost allocation method is equitable, since the LB CRAC would result in the same increase to both the Slice Rate and non-Slice customers' rates.

The PGP and PNGC point to evidence incorporated in the JCG Supplemental rebuttal testimony (Brattebo, *et al.*, WP-02-E-JCG-03, Attachment A) that PGP and PNGC believe demonstrates costs shifts associated with different allocation methodologies. PGP/PNGC Ex. Brief, WP-02-R-PG/PN-01, at 23. This evidence consists of a table of percentage shares that Slice purchasers would pay of the inventory augmentation costs incremental to those augmentation costs covered by the May Proposal base rates. The percentage shares are projected by allocation method, under two scenarios of load reduction (0 aMW load reduction and 1,500 aMW of load reduction), and one scenario of load increase (1,500 aMW of load increase). The table shows the proportion of LB CRAC costs that Slice purchasers would pay, using BPA's approach (allocation by revenues), the approach PGP/PNGC advocate (allocation by MW), and the approach suggested by, but not endorsed by, the JCG in their rebuttal testimony (Brattebo, *et al.*, WP-02-E-JCG-03, at 47-48). Using the figures in the table, the implications of using either the MW or resource-based allocation method for the LB CRAC percentages that would be paid by Slice and non-Slice customers results in the following: If an alternative allocation method would assign 24.6 percent of the costs to Slice purchasers instead of 28.9 percent, then their LB CRAC percentage would decrease in the same ratio that their share decreased. That means that if the revenue allocation method would yield an LB CRAC percentage for all customers of, for example, 200 percent, the MW allocation method would yield an LB CRAC percentage for Slice purchasers of  $(24.6 \text{ percent} / 28.9 \text{ percent}) * 200 \text{ percent} = 170 \text{ percent}$ . Conversely, if the Slice share of LB CRAC costs decreased from 28.9 percent to 24.6 percent, the non-Slice share would increase from  $(100 \text{ percent} - 28.9 \text{ percent}) = 71.1 \text{ percent}$  to  $(100 \text{ percent} - 24.6 \text{ percent}) = 75.4 \text{ percent}$ , and the non-Slice LB CRAC percentage would increase from 200 percent to  $(75.4 \text{ percent} / 71.1 \text{ percent}) * 200 \text{ percent} = 212 \text{ percent}$ .

The table that PGP and PNGC mention shows various contribution shares under assumptions of no load reduction, 1,500 aMW of load reduction, and 1500 aMW of load increase. Using two examples of possible inventory augmentation costs, one leading to an LB CRAC percentage of 200 percent (revenue-based allocation) and the other leading to an LB CRAC percentage of 80 percent (revenue-based allocation), the analysis shows the LB CRAC percentages that Slice and non-Slice customers would pay, if either the MW allocation or the resource-based allocation methods were used instead of BPA's method (revenue-based allocation). *See* Table 1 below:



**Table 1**

<b>LB CRAC Percentage examples for 2002</b>			
Based on DS-BPA: 364			
<b>Example 1 - Large Amount of Inventory Augmentation Costs</b>			
	0 Load Reduction	1500 Load Reduction	1500 Load Increase
<b>BPA method: allocation by revenues</b>			
<i>Slice share</i>	28.90%	35.10%	24.56%
NonSlice LB %	200%	200%	200%
Slice LB %	200%	200%	200%
<b>Allocation by MW</b>			
<i>Slice share</i>	24.60%	30.10%	20.80%
NonSlice LB %	212%	215%	210%
Slice LB %	170%	172%	169%
<b>Allocation by FBS share</b>			
<i>Slice share</i>	28.29%	28.29%	28.29%
NonSlice LB %	202%	221%	190%
Slice LB %	196%	161%	230%
<b>Example 2 - Small Amount of Inventory Augmentation Costs</b>			
	0 Load Reduction	1500 Load Reduction	1500 Load Increase
<b>BPA method: allocation by revenues</b>			
<i>Slice share</i>	28.90%	35.10%	24.56%
NonSlice LB %	80%	80%	80%
Slice LB %	80%	80%	80%
<b>Allocation by MW</b>			
<i>Slice share</i>	24.60%	30.10%	20.80%
NonSlice LB %	85%	86%	84%
Slice LB %	68%	69%	68%
<b>Allocation by FBS share</b>			
<i>Slice share</i>	28.29%	28.29%	28.29%
NonSlice LB %	81%	88%	76%
Slice LB %	78%	64%	92%

Note: The table referenced by PGP and PNGC is based on the assumption of 2,000 aMW of Slice load, so BPA continued using that assumption in considering the equity implications of the table and the arguments of PGP and PNGC; however, this assumption does not bias the conclusions BPA draws from the evidence.

These examples show that using the MW allocation method would result in larger LB CRAC increases to non-Slice customers' base rates than BPA's method (revenue allocation), whether augmentation costs are high or low, and whether there is load reduction, no load reduction, or a load increase. The resource-based allocation method produces higher LB CRAC increases for non-Slice customers than BPA's method (revenue allocation) under most combinations of load reduction and inventory augmentation costs, but sometimes produces lower LB CRAC increases for non-Slice customers. Based on this extrapolation from the evidence PGP and PNGC cites, the revenue-based cost allocation method is equitable, since the LB CRAC would result in the same increase to both the Slice Rate and non-Slice customers' rates.

Further evidence on the record is a cost-shift study contained in BPA's Supplemental Proposal. Supplemental Proposal Study, WP-02-E-BPA-67, at 3-1 to 3-5. This study shows that there were no shifts of costs or risks from Slice purchasers to other customers or Treasury resulted

from offering Slice when using a revenue basis to allocate the LB CRAC. While this study does not examine the issue from a resource-based method of allocation, it is, however, clear from the study that the current proposal to use a revenue basis does not create a cost shift.

BPA stated in its Supplemental testimony that the revenue-based method for allocating these costs is appropriate because the inventory augmentation cost recovery problem is one of revenues. Lefler, *et al.*, WP-02-E-BPA-73, at 14. As a result, BPA has developed an approach that is intended to determine an LB CRAC that reflects the amount of additional revenues needed as a percent of the revenues that would otherwise be collected in the absence of the LB CRAC. *Id.* By using this revenue-based cost allocation method, all the calculations for the LB CRAC are in terms of dollars which translate directly into a new rate with the LB CRAC applied. *Id.*

Last, as discussed in Issue 1, *supra*, BPA's proposed adoption of a revenue-based approach to determining the LB CRAC percent does not contradict the executed Block/Slice Contracts. In any event, section 18 of the executed Block/Slice Contracts provides BPA the right to amend the contract to incorporate changes resulting in decisions in the Final Supplemental ROD.

### **Decision**

*BPA's proposed use of revenues to determine the LB CRAC percent is consistent with the Administrator's Slice principle of no cost or risk shifts to other customers, and does not contradict the executed Block/Slice Contracts.*

### **Issue 3**

*Whether BPA's use of a revenue-based method of cost allocation is unconventional and inconsistent with BPA's historical cost allocation methods and with accepted rate design methods for cost-based rates.*

### **Parties' Positions**

PGP and PNGC assert that BPA's use of a revenue-based method of cost allocation is unconventional and inconsistent with BPA's historical cost allocation methods and with accepted rate design methods for cost-based rates, which typically rely on the principle of cost-causation for allocating costs to customer classes. PGP/PNGC Brief, WP-02-B-PG/PN-01, at 10.

### **BPA Staff Position**

BPA disagrees with PGP and PNGC's assertions. BPA believes that the Subscription products were designed using appropriate rate design and cost allocation methods, as documented in the Subscription Strategy ROD and the May ROD. There is nothing inherently different about the design of the LB CRAC. The LB CRAC was designed to be applied uniformly across all products, keeping the underlying rate design intact, and applied based on revenues, consistent with the prior proposals. May ROD, WP-02-A-02, Appendix 2, at 87-88; Amended Proposal Study, WP-02-E-BPA-59, Appendix, at 6-7.

It is BPA's position that PGP and PNGC have not provided any testimony, studies, or other documentation, in support of this assertion. BPA's position is that, as a result, there is an absence of any evidence on the rate case record supporting the assertions of PGP and PNGC.

### **Evaluation of Positions**

PGP and PNGC contend that using a revenue basis to allocate the LB CRAC is inconsistent with BPA's historical rate design. PGP/PNGC Brief, WP-02-B-PG/PN-01, at 10. As previously noted, BPA is proposing a revenue-based allocation method for increased inventory augmentation costs, that was described in BPA's Supplemental Proposal. Lefler, *et al.*, WP-02-E-BPA-77, at 14. This method of allocating the adjustment associated with the LB CRAC is consistent with the manner in which the CRACs in general were allocated in both the May and Amended Proposals. May ROD, WP-02-A-02, Appendix 2, at 87-88; Amended Study, WP-02-E-BPA-59, Appendix, at 6-7.

PGP and PNGC have submitted no direct or rebuttal testimony that provide any support for their assertions that BPA's use of a revenue-based method of cost allocation is unconventional and inconsistent with BPA's historical cost allocation methods and with accepted rate design methods for cost-based rates. Given the absence of any evidence on the record to support this proposition, there is no basis to adopt their proposal.

However, even if the allocation methodology developed for the LB CRAC was a dramatic departure from the methods BPA has historically used to approach the issue, it does not mean that the revenue-based approach is inherently inequitable. BPA developed an approach to determine an LB CRAC that reflects the amount of additional revenues needed from the LB CRAC as a percent of the revenues that would otherwise be collected in the absence of the LB CRAC. Lefler, *et al.*, WP-02-E-BPA-73, at 14. Then, these incremental revenues covering inventory augmentation costs are apportioned to individual purchasers on the basis of their individual contribution to revenues. *Id.* As explained in further detail in Issue 1, *supra*, this is both an equitable and reasonable way to distribute these costs.

### **Decision**

*BPA's use of a revenue-based method of cost allocation is not unconventional and is consistent with BPA's historical cost allocation methods and with accepted rate design methods for cost-based rates.*

### **Issue 4**

*Whether BPA reaffirmed the resource-based approach to allocating costs, including augmentation costs, on two separate actions in December 2000.*

### **Parties' Positions**

PGP and PNGC assert that two actions taken by BPA in December 2000 reaffirmed the appropriateness of the resource-based approach to augmentation cost allocation. PGP/PNGC

Brief, WP-02-B-PG/PN-01, at 11. The first action was a letter dated December 1, 2000, which provides BPA's official response pursuant to section 4(b)(6)(C)(ii) in the Block/Slice Contract. This section states that "the Forecasted Inventory Solution true-up shall be calculated no later than 30 days after the conclusion of the applicable Subscription Period." The applicable Subscription Period closed on October 31, 2000. The letter provided the calculation for the Forecasted Inventory Solution true-up that would have adjusted the Slice Rate to reflect any additional inventory augmentation costs that resulted from BPA having identified 1,472 aMW of additional load obligations, beyond what was forecast in the May Proposal. That calculation of the Forecast Inventory Solution true-up was to be multiplied by the Slice purchasers' Slice percentages to determine their respective portions of the additional inventory augmentation costs. *Id.*

The second action identified was the issuance on December 1, 2000, of the Federal Register Notice (FRN) of BPA's Amended Proposal. PGP and PNGC make reference to an excerpt in that Amended Proposal, where BPA states that a basic tenet of the Slice product is that Slice purchasers pay a percentage of BPA's costs proportionate to the percentage of the FCRPS that a Slice purchaser elects to purchase. *Id.* at 12.

PGP and PNGC point to these two actions as evidence that BPA still intended to calculate the Slice portion of inventory augmentation costs using a resource-based approach.

### **BPA Staff Position**

It is BPA's position that both of the actions identified by PGP and PNGC are not affirmations by BPA of any intent to implement a resource-based method for allocating LB CRAC inventory augmentation costs. These actions are completely unrelated to the decisions related to the allocation of the LB CRAC. The first action was taken by BPA in the context of meeting its contractual obligation to Slice purchasers, pursuant to section 4(b)(6)(C)(ii) in the Block/Slice Contract. This section states that "the Forecasted Inventory Solution true-up shall be calculated no later than 30 days after the conclusion of the applicable Subscription Period." The applicable Subscription Period closed on October 31, 2000; therefore, BPA was contractually obligated to send a letter to Slice purchasers by December 1, 2000, which provided the calculation for the Forecasted Inventory Solution true-up. BPA and the Slice purchasers executed the Block/Slice Contract, knowing that some terms and conditions in that version of the contract would change later, in order to be consistent with the decisions in the Final Supplemental ROD. As stated in Issue 1, *supra*, BPA has the right, through section 18 in its executed Block/Slice Contracts to amend the contract to incorporate changes resulting from decisions in the Final Supplemental ROD. Subsequent to the transmittal of the Forecasted Inventory Solution true-up letter to Slice purchasers, the methodology for calculating the Slice purchasers' share of increased inventory augmentation costs changed. The changes were a result of this rate proceeding, which was conducted subsequent to December 1, 2000. Therefore, section 4(b)(6)(C)(ii) of the Block/Slice Contract needs revision and is no longer valid, given BPA's proposal for dealing with increased inventory augmentation costs in its Supplemental Proposal.

The second action concerns the issuance on December 1, 2000, of the FRN of BPA's Amended Proposal. This FRN contains a reference to an excerpt of that Proposal in which BPA states that

a basic tenet of the Slice product is that Slice purchasers pay a percentage of BPA's costs proportionate to the percentage of the FCRPS that a Slice purchaser elects to purchase. PGP/PNGC Brief, WP-02-B-PG/PN-01, at 12. PGP and the PNGC contend that this commits BPA to a resource-based method for allocating increased inventory augmentation costs. BPA's Amended Proposal did contain a resource-based methodology that assigned a portion of BPA's increased net inventory augmentation costs to Slice. *Id.* The design of the LB CRAC in BPA's Supplemental Proposal contains a different approach to recovering increased inventory augmentation costs. Burns and Berwager, WP-02-E-70, at 12. It is BPA's position that there was no obligation to remain consistent with the resource-based cost allocation methodology used in the Amended Proposal.

There has been no proposed change to the Slice Rate adopted in the May ROD. It is BPA's position that the basic tenet quoted above still holds true with respect to the design of the product and the underlying base Slice Rate adopted in the May ROD. For the recovery of increased inventory augmentation costs, BPA has designed a methodology that allocates these costs in a different manner between all products subject to the LB CRAC, as discussed in Issue 1, *supra*. In doing so, BPA ensures that the amount of additional revenues needed to cover inventory augmentation costs is apportioned to individual purchasers on the basis of their individual contribution to revenues.

### **Evaluation of Positions**

PGP and PNGC contend that BPA's own actions demonstrate an intent to use a resource-based method for allocating the LB CRAC. PGP and PNGC erroneously point to a letter sent on December 1, 2000, to Slice purchasers containing the calculation of the Forecasted Inventory Solution True-Up as an affirmation of BPA's intent to proceed in the direction of resource-based cost allocation for all approaches to recovering the increased cost of inventory augmentation. PGP/PNGC Brief, WP-02-B-PG/PN-01, at 12. This is not the case, and BPA has not made any such assertions. As BPA notes, this letter simply complied with a provision of the Block/Slice Contract requiring BPA to make the determination contained in that letter no later than 30 days after the close of Subscription. While the methodology used to allocate augmentation costs in this letter is resource-based rather than revenue-based, the only evidentiary value the letter provides is showing that BPA complied with its contractual obligations. As previously noted, the fact that the May Proposal used a resource-based method to allocate augmentation costs to Slice purchasers does not obligate BPA to adopt a similar method in this phase of the proceeding.

BPA also acknowledges that at the time of the Amended Proposal, the approach to recovering increased inventory augmentation costs from Slice purchasers was resource-based. Procter, *et al.*, WP-02-E-BPA-64, at 9. With the Supplemental Proposal, BPA designed a method for recovering augmentation costs that is revenue-based, and that applies to all purchasers of products subject to the LB CRAC, not just to purchasers of the Slice product. Lefler, *et al.*, WP-02-E-BPA-73. There was no obligation on BPA's part to remain consistent with a resource-based methodology in the Amended Proposal. BPA's obligation was to recover increased inventory augmentation costs and to allocate them in an equitable manner.

PGP and PNGC contend that the basic tenet of the Slice product, whereby Slice purchasers pay a percentage of BPA's costs proportionate to the percentage of the FCRPS that a Slice purchaser elects to purchase, must be upheld. PGP/PNGC Brief, WP-02-B-PG/PN-01, at 14. BPA is ensuring that this basic tenet still holds true with respect to the design of the product and the underlying base Slice Rate that was adopted in the May ROD. See Supplemental Proposal Study, WP-02-E-BPA-67, at 4-1. However, for the allocation of increased inventory augmentation costs (beyond the cost already included in the base rates for products subject to the LB CRAC), BPA has designed a methodology that recovers these costs in a different manner, as discussed in Issue 1, *supra*. The methodology in the LB CRAC assures that increased inventory augmentation costs are recovered from individual purchasers of products subject to LB CRAC in proportion to their individual contribution to revenues from these same products. Lefler, *et al.*, WP-02-E-BPA-73, at 14. This is an equitable and reasonable way to recover these costs.

### **Decision**

*BPA's two separate actions in December 2000 did not constrain BPA to exclusively using the resource-based approach to allocating costs, including augmentation costs.*

### **Issue 5**

*Whether BPA should separately calculate the LB CRAC for Slice sales.*

### **Parties' Positions**

The Springfield Utility Board (SUB) proposes that BPA not adjust the LB CRAC for Slice sales for load loss during adjustment periods that do not coincide with Slice/Block entitlement calculations. SUB Brief, WP-02-B-SP-02, at 10. In its rebuttal testimony, SUB is concerned that changes in retail load for Slice purchasers are assessed on an annual basis, and not in a timeframe (every six months) consistent with the LB CRAC calculation. Nelson, WP-02-E-SP-03, at 14. Therefore, SUB contends, at the end of the six-month period when changes in retail load for Slice purchasers have not been assessed, Slice purchasers would gain the benefit of potential reductions in BPA's augmentation responsibilities, but would have not contributed to this reduction of augmentation responsibilities as non-Slice customers would have contributed. *Id.* SUB reiterates this position in its brief on exceptions. SUB Ex. Brief, WP-02-R-SP-02, at 11.

The Western Public Agencies Group (WPAG) disagrees with SUB's suggestion that the LB CRAC should not be adjusted during periods that do not coincide with annual Slice entitlement calculations. WPAG believes that this would be extremely difficult, if not impossible to implement, and would require BPA to do all the LB CRAC calculations twice with differing loads for Slice and non-Slice customers. WPAG Brief, WP-02-B-WA-01, at 18.

Avista Corp. (Avista), Idaho Power Company (IPC), PacifiCorp, Portland General Electric (PGE), and Puget Sound Energy, Inc. (PSE) (Companies) also disagrees with SUB's proposal regarding the LB CRAC. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 6. The Companies state that the Partial Stipulation and Settlement Agreement reflected in BPA's Supplemental Proposal

was a balanced proposal that represented compromises on the part of all of the parties to the settlement. The Partial Stipulation and Settlement Agreement represents a package that addresses BPA's financial health and is delicately balanced on the give-and-take of each party. Any changes to the settlement risks upsetting this balance, and for this reason, the Companies propose that BPA reject SUB's proposal to change the LB CRAC as it is applied to the Slice sales. *Id.*

### **BPA Staff Position**

As stated in its rebuttal testimony, BPA does not agree with SUB's proposed method of calculating the LB CRAC for Slice and non-Slice customers separately, in order to reflect load loss from those respective groups of customers. Lefler, *et al.*, WP-02-E-BPA-77, at 12. Changes (increases or decreases) in the load of customers purchasing load-following products do affect the LB CRAC calculations, and changes in the load of Slice/Block purchasers do not affect such calculations. This does not reflect a cost shift. *Id.* at 11 and 12. BPA determines the need for additional market purchases to meet load by subtracting expected loads from FCRPS output, as these amounts are defined in the GRSPs. BPA buys resources to meet load, not to meet the load of one separate set of customers. As a result, BPA has proposed an LB CRAC methodology that reflects this principle. *Id.*

### **Evaluation of Positions**

SUB is proposing to develop an LB CRAC that accounts for subtle differences in the ways that the Slice and non-Slice products handle load loss. SUB, in its brief, repeats this argument. SUB Brief, SP-02-B-SP-02, at 10. The change that SUB is proposing for the LB CRAC is not necessary. The LB CRAC was designed to be applied to all Subscription products in a uniform manner, preserving the underlying design of the individual Subscription products. *See* Burns and Berwager, WP-02-E-BPA-70, at 6, 7. The justification for Subscription product design differences has been documented in the Subscription ROD. SUB, in its brief on exceptions, repeats this argument. SUB Ex. Brief, WP-02-R-SU-02, at 11. Furthermore, the change that SUB is proposing would be difficult to implement and would overlay yet another layer of complexity on an already complex adjustment process. If BPA were to implement this change, the resulting change in the LB CRAC would be minimal and not worth the significant workload to implement the change. WPAG also agrees that this is an unnecessary complication and asserts that this change may serve to over-collect augmentation costs from Slice purchasers for the benefit of non-Slice customers. WPAG Brief, WP-02-B-WA-01, at 18. The Companies also recommend that BPA reject SUB's proposal based on the fact that this change unravels part of the Partial Stipulation and Settlement Agreement, which is delicately balanced on the give-and-take of each party. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 6.

### **Decision**

*BPA will not calculate a separate LB CRAC for Slice purchasers.*

## **Issue 6**

*Whether the LB CRAC calculations are subject to review or audit by BPA's independent audit firm and whether the report of that audit will be made available to customers.<sup>1</sup>*

### **BPA's Proposal**

The Partial Stipulation and Settlement Agreement states that the determination of the Augmentation True-Up will be subject to audit by BPA's independent outside auditing firm, and the results of such audits will be available to customers. One year after the end of each of the six-month periods described in Section B of the Partial Stipulation and Settlement Agreement, the parties, other than BPA, will be allowed to review or audit the documentation of any augmentation power purchase made by BPA that is used either in the calculation of the Assumed Augmentation Net Cost, Revised Slice Share of Net Additional Augmentation Costs or the non-Slice Share of the Revised Net Additional Augmentation Costs. Burns and Berwager, WP-02-E-BPA-70, Attachment A, Exhibit A, Section B(12). Prior to these audits, customers will not have access to the terms of the power purchases. *Id.*

BPA has proposed that the audit results that will be made available to customers will consist of an affirmative statement from the audit firm as to: (a) the validity of the calculations performed by BPA covered by the audit; and (b) any change in billing as a result of the audit. Lefler, *et al.*, WP-02-E-BPA-73, at 14. BPA's proposed approach provides for an independent third party to verify the accuracy of the calculations included in the Proposed Methodology. As a result, BPA sees no difference in the possible outcome from any such blind audit. *Id.*

BPA's proposal is to allow verification by BPA's independent outside auditor of the accuracy of the LB CRAC calculations. The report of that audit would then be provided to customers who request that report. The report will be a statement by the audit firm as to the accuracy of the calculations in the LB CRAC. Twelve months after the end of any 6-month period, BPA will provide customers with documentation that identifies the detailed data used as inputs in the LB CRAC calculations. During the annual audit of the LB CRAC calculations, BPA's independent auditor will use agreed upon procedures to examine the components used in the LB CRAC calculation and to validate the accuracy of the calculation as defined in the GRSPs. This provides customers adequate assurance that BPA has accurately calculated the LB CRAC.

### **Decision**

*BPA will allow its independent audit firm to review the calculations of the LB CRAC once annually for purposes of validating the accuracy of the LB CRAC calculations, and a report of that audit attesting to the accuracy of the calculations will be provided to customers upon the customer's request.*

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<sup>1</sup> While BPA raised this issue in its direct case, Lefler, *et al.*, WP-02-E-BPA-73, at 30, this issue was not raised as an issue in testimony by any other party. The purpose of including this as an issue is to clarify the intent of BPA's proposal.



#### 4.3.2 Financial-Based Cost Recovery Adjustment Clause

##### Issue

*Whether the FB CRAC design should be changed so that any adverse financial conditions which BPA experiences prior to October 2001 would not be borne solely by non-Slice customers.*

##### Parties' Positions

SUB argues that the design of the FB CRAC presented in the Supplemental Proposal places an unfair burden on non-Slice customers, since in the first year of the rate period, there is no cap on the revenues that can be collected. Therefore, they argue, "adverse financial conditions which BPA experiences prior to October 1, 2001 are borne solely by non-Slice customers." SUB Brief, WP-02-B-SP-02, at 7. They propose "two mutually exclusive solutions: 1) require Slice purchasers to participate in the FB CRAC in the first year or 2) allow non-Slice customers the option to forfeit the DDC in exchange for not being exposed to the FB and Safety Net (SN) CRAC's which differ from the May Proposal." *Id.*

In brief on exceptions, SUB argues that, with BPA's studies showing a 49 percent likelihood of the FB CRAC triggering in the first year, and SUB's studies showing a 69 percent likelihood, and ending reserve forecasts decreasing, BPA's proposal does show a cost shift to non-Slice customers. SUB Ex. Brief, WP-02-R-SP-02, at 7-9.

The IOUs disagree, stating "The Companies do not support the changes suggested by SUB. (*See* WP-02-E-JCG-03 at 30-38.) . . . (T)he Partial Stipulation and Settlement Agreement represents a package that addresses BPA's financial health and is delicately balanced on the give-and-take of each party. Any changes to the settlement risks upsetting this balance. For this reason, among others, SUB's recommendations should be rejected." IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 6.

##### BPA Staff Position

BPA's Supplemental Proposal specifies that customers taking the Slice product will neither be subject to the FB CRAC (in any year in the rate period), nor eligible for dividends distributed under the DDC. Lefler, *et al.*, WP-02-E-BPA-77, at 18.

If the FB CRAC were implemented during the first year of the rate period, the Slice purchasers would be exempt from paying increased rates triggered by a forecast of low end-of-FY 2001 ANR. *Id.* By contrast, if BPA begins the next rate period with high ANR, the Slice purchasers would see no benefits from the DDC should it trigger in subsequent years. BPA believes that this is an equitable tradeoff. *Id.*

##### Evaluation of Positions

BPA's proposed rate design has the Slice product exempt from the FB and SN CRACs because Slice purchasers assume a proportionate share of BPA's financial risks, and has the Slice product

exempt from the DDC because Slice purchasers receive a proportionate share of the benefits of the federal system, such as actual nonfirm power deliveries, through the product design. Supplemental Study, WP-02-E-BPA-67, at 1-10, lines 5-8. Both Slice purchasers and non-Slice customers contribute to the mitigation of BPA's risk. Slice purchasers do this by taking on the obligation to pay actual expenses; non-Slice customers do this by being subject to the FB CRAC and SN CRAC. Both Slice purchasers and non-Slice customers stand to benefit from good fortune also. Slice purchasers do this by obtaining the rights to a share of BPA's nonfirm power, when there is any. Non-Slice customers do this by being eligible for DDC payouts, when there are any. If BPA allowed non-Slice customers a chance to opt out of the FB CRAC, BPA's risk mitigation package would be reduced unacceptably, even if the opting out did not accord those customers opting out an inequitable advantage.

BPA generally agrees with SUB that those customers who will be Slice purchasers in the 2002 to 2006 rate period were part of the BPA system prior to 2002, and if circumstances in 2001 reduce BPA's reserves, Slice purchasers will not be subject to restoring the reserves through the FB CRAC. However, if circumstances in 2001 are less adverse, Slice purchasers will not benefit from a reduced exposure to the FB CRAC. Lefler, *et al.*, WP-02-E-BPA-77, at 18. In addition, Slice purchasers have been contributing to BPA's reserves, whatever level those turn out to be at the end of 2001, and after 2001 those Slice purchasers will be paying for BPA risks directly and not benefiting from the existence of those reserves. *Id.* Therefore, subjecting the Slice purchasers to the FB CRAC for 2002 would not be equitable.

SUB's numbers for the likelihood of the FB CRAC triggering are based on its assertion that the \$50 million working capital assumption in the ToolKit must be increased to \$300 million. This is incorrect; see the issue in section 4.5 *infra* on the \$50 million working capital assumption. BPA's estimate of the likelihood of the FB CRAC triggering is 32 percent. Final Supplemental Study Documentation, Chapter 5, attachments 2 through 7. SUB's assertion that declining reserve levels cause this likelihood to increase does not demonstrate a cost shift to non-Slice customers, only that declining reserves would increase the likelihood of non-Slice customers paying FB CRAC rates.

SUB has asserted that BPA's reserves have continued to decline. SUB Ex. Brief WP-02-R-SP-02, at 8. That is no longer the case. While BPA's expected value of starting 2002 reserves attributable to the generation function had fallen to \$309 million at the time of BPA's Amended Proposal, the expected value of BPA's starting 2002 reserves attributable to the generation function in this Supplemental Proposal is now \$429 million. Final Supplemental Proposal Study, WP-02-FS-BPA-09, at 5-3.

The CRAC and DDC designs included in the Supplemental Proposal are part of the negotiated Partial Stipulation and Settlement Agreement. BPA staff believes the trade-off between the Slicers not being subject to the FB CRAC and not being eligible for the DDC is an equitable one. Lefler, *et al.*, WP-02-E-BPA-77, at 18.

As the IOUs state, the risk mitigation package represents a compromise approach which over-all is balanced. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 6. To make the change

recommended by SUB would likely create an imbalance of an undetermined or undeterminable size.

### **Decision**

*BPA will not modify the FB CRAC design to include Slice purchasers in the first year, or to allow non-Slice customers to choose to be exempt from the FB CRAC, SN CRAC, and DDC.*

#### **4.3.3 Safety-Net Cost Recovery Adjustment Clause and Dividend Distribution Clause**

##### **Issue 1**

*Whether BPA has taken unnecessary and unacceptable risks by not using a rolling five-year forecast to trigger the SN CRAC and DDC.*

##### **Parties' Positions**

Northwest Energy Coalition (NWECS)/Save Our Wild Salmon (SOS) argue that BPA should modify its proposed SN CRAC and DDC mechanisms so they would function by using a rolling five-year forecast, thus maximizing BPA's flexibility. NWECS/SOS Brief, WP-02-B-NA/SA-02, at 8-10. They argue that, since BPA's proposed SN CRAC triggers only a few months in advance of an actual Treasury deferral, it cannot anticipate serious problems soon enough to affect the TPP. Weiss, WP-02-E-NA/SA-04, at 8.

NWECS/SOS cites and agrees with earlier BPA testimony criticizing a DDC design which did not have a forecast element, for a lack of flexibility and adaptability, the potential for shifting risk to Treasury and taxpayers, and inconsistency with the Principles all pose [great] political risks. NWECS/SOS Brief, WP-02-B-NA/SA-02, at 8.

By contrast, the parties involved in the Partial Stipulation and Settlement Agreement reflect support for the SN CRAC and DDC designs presented in the Supplemental Proposal and, in some cases, opposition to the NWECS/SOS proposal. JCG Brief, WP-02-B-JCG-01; WPAG Brief, WP-02-B-WA-01; IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02; and NRU Brief, WP-02-B-NI-03. As described by the Joint Customers:

In essence, the SN CRAC allows BPA to truncate the five-year rate period and make an adjustment to the FB CRAC parameters when it is clear that the LB and FB CRACs are inadequate to ensure timely payment to the Treasury. It also requires that any such change to the FB CRAC parameters will be subjected to review by the FERC, which will ensure that any such change satisfies the cost recovery requirement of section 7(a) of the Regional Act. The SN CRAC is the ultimate demonstration that the region is committed to providing BPA with the tools necessary to fulfill its obligations to the Treasury regardless of what may transpire during the rate period. By proposing the SN CRAC, the JCG has

provided to BPA during this rate period a financial tool that will be available in this period of unprecedented wholesale market volatility if all else fails.

An integral element of this package of enhanced risk mitigation tools proposed by the JCG is the revised Dividend Distribution Clause (“DDC”). As set forth in BPA’s Amended Proposal, the original DDC was a discretionary mechanism that only required the Administrator to consider returning financial reserves in excess of a specific amount. . . The operation of the DDC is no longer a discretionary act. . . revisions to the DDC are driven by notions of equity and fairness. The LB, FB, and SN CRACs cover virtually every contingency BPA may face in the rate period. . . equity requires that those who have provided BPA the funds needed to ensure its financial health should be assured that they will get back funds that are not needed. In this respect, the mandatory nature of the DDC nicely complements the LB, FB, and SN CRACs by providing the customers both the benefits and the burdens of helping BPA fulfill its financial obligations.

JCG Brief, WP-02-B-JCG-01, at 12-14.

WPAG similarly asserts the automatic triggering of the DDC is important because it “provides to customers the assurance that if they make the sacrifices needed to ensure BPA’s fiscal integrity in the bad times, they will benefit from revenues in excess of BPA’s needs in the good times.” WPAG Brief, WP-02-B-WA-01, at 7. It is BPA’s way of saying that the customers, and through them the region, will only be asked to contribute financial reserves that BPA needs and no more. *Id.*

In addition to supporting the SN CRAC and DDC design in the Supplemental Proposal, Avista, IPC, PacifiCorp, PGE, and PSE objected to the proposed five-year forward look. They argue that the ability to trigger the SN CRAC only within the year of an expected deferral is part of the negotiated package of the Supplemental Proposal. “As part of this negotiation, the LB and FB CRAC would be modified to reduce the possibility of the SN CRAC by using semi-annual true-ups for augmentation and uncapping the first year FB CRAC.” IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 6 “Part and parcel to the JCG agreeing to an uncapped first year FB CRAC and semi-annual true-ups for augmentation is the idea that any overpayments be returned to the customers taking the risk of payment. Again, the inability to accurately forecast conditions in the long-term future militates against subjecting the DDC to a five-year forward look” *Id.* The Administrator should reject these recommendations as unnecessary and inconsistent with the Partial Stipulation and Settlement Agreement. *Id.*

NRU argues that the SN CRAC and DDC designs in the Supplemental Proposal more effectively mitigate rate shock than would be the case if they triggered based on a five-year forecast. They state that using a five-year forecast to trigger the DDC would have the effect of substantially reducing the likelihood that the DDC would ever trigger, and it would lead to the accumulation of potentially enormous sums of customer money in BPA reserves. NRU Brief, WP-02-B-NI-03, at 13-14.

“Any adverse turn in BPA’s financial position affecting future years could easily be addressed by adjustment of the FB and SN CRACs during the rate period.” *Id.* They also argue that looking beyond the current year and beyond the rate period in determining whether or not to trigger the SN CRAC is not acceptable for the same reasons as described with regard to DDC. “Current year and rate period conditions should be the determining factor for triggering the SN CRAC and for setting rates in this rate period.” *Id.*

In their brief on exceptions, NRU states that BPA should not use a rolling five-year forecast to determine the amount of funds to be collected under the SN CRAC or distributed under the DDC. NRU Ex. Brief, WP-02-R-NI-02, at 4.

### **BPA Staff Position**

The SN CRAC in the Supplemental Proposal is part of the integrated package developed in the Partial Stipulation and Settlement Agreement. It is designed to trigger if the Administrator determines that reserves attributable to generation are declining such that, even with implementation of FB CRAC and any augmentation true-ups:

1. there is at least a 50 percent likelihood that BPA will miss the next payment to Treasury or will miss a payment to any other creditor; or
2. BPA has already missed a payment to Treasury or any other creditor.

Lefler, *et al.*, WP-02-E-BPA-77, Attachment A, at 30.

Because SN CRAC can be triggered by the anticipation of missing the next payment to Treasury, it could not trigger prior to the fiscal year in which the deferral is forecast to occur. As such, it has been designed in a way that it is not likely to trigger in time to prevent a missed Treasury payment but to help avoid a second miss. 2002 Supplemental Proposal Study, WP-02-E-BPA-67, at 5-12.

### **Evaluation of Positions**

As noted *supra*, the SN CRAC and DDC mechanisms described in BPA’s Supplemental Proposal were part of a negotiated Partial Stipulation and Settlement Agreement that both BPA staff and the JCG believed to be reasonable and workable. JCG Brief, WP-02-B-JCG-01, at 12-14. NWEC/SOS’s direct testimony, however, raised questions about the effectiveness of these mechanisms. Weiss, WP-02-E-NA/SA-03, at 8. BPA responded to those in rebuttal testimony. Lefler, *et al.*, WP-02-E-BPA-77, at 19-21. There BPA asserted that the five-year rolling forecast offered little, if any, advantage in heading off the impacts of significant changes in market or hydro conditions. *Id.* BPA also argued that it would likely create significant implementation problems for BPA and its customers, since it would be difficult to get agreement on what rates should be, or to justify a significant increase, when working with forecasts of “surprise” events several years in advance. *Id.* In its initial brief, NWEC/SOS further clarified (or expanded) several points made in its direct testimony: (1) the types of uncertainty the five-year rolling forecast allegedly addresses that a mechanism with a shorter time horizon

would not; and (2) the details of how its SN CRAC would operate. NWEC/SOS Brief, WP-02-B-NA/SA-02, at 8-10. Neither of these points alters the conclusion BPA presented in its rebuttal testimony.

In direct testimony, NWEC/SOS asserted that the SN CRAC mechanism contained in the Supplemental Proposal had been “modified significantly from [NWEC/SOS’s] design.” Weiss, WP-02-E-NA/SA-03, at 8. NWEC/SOS’s direct testimony, while strongly arguing for a five-year forward-looking SN CRAC and DDC, provided little detail on how these mechanisms would actually operate. Neither did the testimony provide any citations from the record to indicate where NWEC/SOS’s “original designs” might be described.

In its initial brief, NWEC/SOS identified the source of the alternative SN CRAC design as being in their May Proposal initial brief, in their October 2000 letter in response to a BPA request on how to deal with its new problems, and again in their Supplemental Rate Case direct testimony. NWEC/SOS Brief, WP-02-B-NA/SA-02, at 8.

In their February 2000 initial briefs, NWEC/SOS, CRITFC/Yakama, and the Oregon Public Utility Commission (OPUC) proposed an uncapped CRAC with a five-year rolling forecast. (See NWEC/SOS Brief, WP-02-B-NA/SA-01, at 31; CRITFC/Yakama Brief, WP-02-B-CR/YA-01, at 42; OPUC Brief, WP-02-B-OP-01, at 9-10.) This CRAC proposal, however, had not been introduced by NWEC/SOS, CRITFC/Yakama, or OPUC prior to the filing of those initial briefs in 2000. Because the other parties in the rate case had not been provided an adequate opportunity to offer refutation or rebuttal on this design and because the evidentiary arguments had not been based upon cited material in the record, the Administrator did not give it any weight but did offer an evaluation of the position. These initial briefs violated Sections 1010.11(a) and 1010.13(a) of BPA’s *Rules of Procedure Governing Rate Hearings* and were not considered in the May ROD. (See May ROD, WP-02-A-02, at 7-33).

Although not referred to as a “Safety-Net” CRAC in the February 2000 initial briefs (since there was only a single CRAC component in the May Proposal), the design clearly has the same purpose and function, allowing BPA to collect potentially very large amounts of additional revenues under emergency conditions. But while NWEC/SOS’s February 2000 initial brief provides additional detail about the specifics of the SN CRAC design, as noted *supra*, this additional detail in no way alters the conclusions about a five-year forecast described in BPA’s rebuttal testimony.

As BPA argued in rebuttal testimony in this rate proceeding, “from a strictly technical standpoint, to expect that a forward-looking provision of the SN CRAC would be effective, there must be some reason for believing the events of greatest concern could actually be foreseen and acted upon in a timely fashion.” Lefler, *et al.*, WP-02-E-BPA-77, at 20.

There are several general sources of uncertainty that could produce the type of sudden and major impacts on BPA’s financial situation to which the SN CRAC was designed to respond. The five-year forward-looking SN CRAC design offered by NWEC/SOS provides no advantage in dealing with any of these sources. While it is obviously not possible to predict “surprise” events such as natural disasters or unplanned outages, as recent events illustrate, it is almost as difficult

to anticipate extreme volatility in market prices and/or weather conditions. Recent events in the West Coast power market demonstrate that markets are highly volatile and that forecasts of their expected behavior may become obsolete virtually overnight. *Id.* Considering that market price forecasts prepared in spring 2000 were unable to predict or even anticipate the magnitude of change that actually occurred later in that year, it is unreasonable to expect that a forward look conducted one to five years earlier would have prepared the region for the sudden shift in prices that actually occurred. *Id.* If BPA had been able to implement some form of SN CRAC for the FY 1996-2001 rate period, it likely would have made little difference whether or not it was forward-looking in terms of its ability to deal with the problems the region is facing currently. *Id.*

In its initial brief, however, NWECS/SOS cite cross-examination testimony in which BPA's risk mitigation panel stated that it is "conceivable that an event could be foreseen beyond the end of a fiscal year that would have a sufficient financial impact with sufficient probability that if the SN CRAC did look out that far it might trigger." NWECS/SOS claim that with this statement, BPA contradicts the statement cited above from its rebuttal testimony. NWECS/SOS Brief, WP-02-B-NA/SA-02, at 9.

The fact that there are some events that might be predictable does not contradict the assertion that, generally speaking, the events of greatest concern are difficult if not impossible to predict. The type of events that can be predicted are usually those that are the result of policy or business decisions, where the decision makers themselves specify the timetable for implementation. For example, BPA might, in 2002, become aware of large new costs due to regulatory changes that need to be paid beginning in 2005.

There are, however, problems with applying NWECS/SOS's five-year forward-looking SN CRAC in such a situation. First of all, in many instances, NWECS/SOS's design would not provide any advantage whatsoever to BPA given circumstances like the example above. Under NWECS/SOS's SN CRAC as described in their initial brief for the May Proposal, 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. NWECS/SOS Brief, WP-02-B-NA/SA-01, at 31.

Under this design the SN CRAC would be triggered only if reserves fell below a certain threshold level. If, in the above example, BPA had ample reserves in the FY 2002-2004 period, NWECS/SOS's design would not even trigger the SN CRAC process, despite the fact that BPA had knowledge of imminent cost exposure.

Regardless of what sort of triggering mechanism might activate a five-year forward look, however, this SN CRAC design presents a practical implementation problem noted in BPA's rebuttal testimony (and reiterated in the excerpts from customer briefs cited *supra*):

This inability to forecast major events or outcomes of decisions accurately beyond a short time horizon would create a significant practical problem during SN

CRAC implementation. It is difficult to get agreement on what rates should be when working with forecasts of “expected” outcomes. Attempting to justify a significant increase in rates based upon a forecast of “surprise” events several years in advance might prove impossible. The short forward look of the current design greatly increases the likelihood of consensus regarding which factors justify rate increases and what the appropriate response should be.

Lefler, *et al.*, WP-02-E-BPA-77, at 20.

While it might seem that achieving consensus on an event such as the one described by NWECS/SOS above might be easy, this is not necessarily the case. Although there might be certainty about the costs BPA would be facing in such a situation, there would still be uncertainty about the impact of the new costs on revenues. As BPA’s Risk Analysis and Risk Mitigation Studies show, the range of variation in hydro and market conditions is so large that it can fully mitigate or significantly exacerbate the impacts of large costs on BPA’s revenue streams. See Final Study, WP-02-FS-BPA-09, Chapters 4 and 5. Thus, ascertaining and getting agreement on what, if any, rate adjustment would be needed three years out would not be as simple or straightforward as NWECS/SOS believes.

The SN CRAC and DDC mechanisms described in BPA’s Supplemental Proposal were part of a negotiated Partial Stipulation and Settlement Agreement. BPA’s financial health cannot be separated from the financial health of its customers. The characteristics of the SN CRAC and DDC in the Supplemental Proposal reflect an integrated design that addresses the financial concerns of both BPA and the JCG and sets limits on the magnitude of expected rate adjustments that the JCG finds reasonable. NWECS/SOS assert that the DDC has been weakened by its redesign as a “reverse CRAC “ and admonishes BPA for not rebutting its own justification in the May Proposal for using a five-year rolling forecast as the basis for determining dividend distributions. This justification, however, was meaningful only in terms of the entire risk mitigation package presented in the May Proposal. It applied to a DDC design that was counterbalanced by a single, limited CRAC mechanism, and lacked the revenue generating potential of the LB and SN CRACs that form the cornerstone of the Supplemental Proposal. As WPAG points out, the change, made to the design of the DDC was needed because it provides customers the assurance that, if they make the sacrifices needed to ensure BPA’s fiscal integrity in the bad times, they will benefit from revenues in excess of BPA’s needs in the good times. WPAG Brief, WP-02-B-WA-01, at 7.

### **Decision**

*The SN CRAC and DDC mechanisms described in the Supplemental Proposal are reasonable and do not expose BPA to unnecessary or unacceptable levels of risk. BPA will not use a rolling five-year forecast to determine the amount of funds to be collected under the SN CRAC or distributed under the DDC.*



## **Issue 2**

*Whether distributions from triggering the DDC should be adjusted based on the market value of deviations from the 2000 FCRPS Biological Opinion (BO) operations due to a financial emergency.*

### **Parties' Position**

CRITFC/Yakama argue that any DDC distributions should be reduced by the market value of any deviations from the 2000 FCRPS BO operations due to a financial emergency, and that amount should be set aside to be used for fish mitigation and energy conservation. CRITFC/Yakama Brief, WP-02-B-CR/YA-02, at 23, lines 18-22. They state that if BPA decides not to honor the measures of the BO, it should not profit from the deviations. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-92, at 6. *Id.*

NRU states that the threshold for the DDC should not be changed to reflect the results of a declaration of system emergency. NRU Brief, WP-02-R-NI-02, at 4.

### **BPA Staff Position**

BPA's proposed DDC is designed such that the threshold for any fiscal year will be adjusted upward by the following:

- A. In the event that there has been a power system emergency (as defined in "FCRPS Protocols for Emergency Operation In Response to Generation or Transmission Emergencies" dated September 22, 2000, or amendments thereto) during the fiscal year, and BPA has agreed to provide additional funding to mitigate the impact of the emergency operations on fish and wildlife, any of the additional emergency-related funding which BPA has not spent during that fiscal year will be added to the threshold amount for that year; and/or
- B. BPA fish and wildlife operation and management (O&M) ("direct program") costs previously budgeted for expenditure in that FY that were not spent in that FY and for which a need continues, will be added to the threshold amount for that year.

Lefler, *et al.*, WP-02-E-BPA-73, at 36, line 16 to page 37, line 2.

### **Evaluation of Positions**

BPA has proposed a provision that is similar to CRITFC's proposal. Both proposals adjust the DDC provisions if there is a deviation from the BO operations due to the declaration of a power system emergency. There are differences in the proposals, however.

BPA's proposal adjusts the DDC threshold upward if a power system emergency is declared and BPA has agreed to provide additional funding to mitigate the impact of emergency operations, to the extent BPA has not spent the additional emergency-related funding in that fiscal year.

Lefler, *et al.*, WP-02-E-BPA-73, at 36, lines 16-24. BPA's proposal also includes an additional provision for adjusting the threshold if BPA's budgeted fish and wildlife operation and maintenance costs have not been spent in the fiscal year, and a need for the expenditure continues. *Id.*, at 36-37.

CRITFC's proposal differs, first, in that it only addresses deviations from the BO operations due to a power system emergency. CRITFC/Yakama Brief, WP-02-B-CR/YA-02, at 23, lines 18-19. It does not include BPA's second provision for a DDC adjustment.

Second, CRITFC's proposal would have the adjustment based on the market value of any deviations from the BO operations. *Id.* BPA's proposal includes an adjustment based on the cost of any measures adopted to mitigate the impact of the change in operations. Lefler, *et al.*, WP-02-E-BPA-73, at 36-37.

BPA believes the appropriate foundation for any adjustment of the DDC threshold related to impacts of power system emergencies is mitigation of any impact on fish, not dollars. The purpose of the clause is to allow for actions that mitigate the impact of the emergency operations, and to decrease any dividend distribution by the amount of any expense of the mitigation not completed in the fiscal year of the emergency operations. Use of a market value of deviations in operations due to a power system emergency is unrelated to the impact on fish and unrelated to the potential mitigation of that impact. For example, there could be a circumstance in which the impact of the emergency operations was determined by the appropriate fisheries agencies to be negligible but in which the market value of the change in operations is enormous. It clearly would not make sense to adjust the DDC threshold by an enormous amount based on the high market value of deviations in hydro operations when the impact on fish was negligible. This is not a question of who might determine if an impact is negligible; it is an observation that adjusting fish budgets on a basis of the market value of water, which is not related to the fisheries impact of the operations change, contains the possibility for nonsensical outcomes.

BPA's proposal does not determine or place any bounds on the nature of the mitigation, nor does it place any cap on the cost of mitigation efforts. It is a reasonable approach to ensure that funds needed for the mitigation of emergency operations which may have benefited power production are not distributed prematurely.

CRITFC/Yakama argue that BPA should not "profit" from deviations in BO operations. CRITFC/Yakama Ex. Brief, WP-02-R/CR/YA-02, at 6. However, if BPA has declared a power system emergency, it is because BPA's situation is truly dire, and in the case of power system emergencies base on financial criteria, it is because BPA cash position is in a genuine cash emergency. Setting aside the market value of hydro operations deviations, to be used only for fish and wildlife use, would prevent BPA from conserving cash and avoiding insolvency – this would clearly defeat the purpose of a financially-based power system emergency.

### **Decision**

*BPA's design of the DDC is equitable, and should not be changed so that the DDC threshold is adjusted by the market value of any changes in operations made as a result of the declaration of a power system emergency.*

### **Issue 3**

*Whether the DDC should apply to curtailed load under take-or-pay contracts.*

### **Parties' Position**

The DSIs claim that during hearings BPA proposed to exclude power subject to such take-or-pay obligation from calculation of the DDC credits to the extent that a customer has not taken delivery of all of its contracted power and BPA has credited disposal proceeds to offset part of its take-or-pay obligation. DSI/Alcoa Brief, WP-02-B-DS/AL-02, at 40.

In their brief on exceptions, the DSIs argue that it is fundamentally unfair to hold a DSI fully responsible for the base rate plus all CRACs on its Block Sales Contract purchases (which may or may not be mitigated by market sales) yet deny them a credit to the extent that subsequent events prove the total charge to be excessive.” DSI Ex. Brief, WP-02-R-DS/AL-02, at 5-6.

NRU states that the DDC should not apply to curtailed loads for which the customer did not pay BPA. NRU Ex. Brief, WP-02-R-NI-02, at 4.

### **BPA Staff Position**

The Customer DDC Amount, the amount to be returned to power customers, is returned to customers in proportion to the DDC Customer Revenue Amount. Lefler, *et al.*, WP-02-E-BPA-77, Attachment A, at 33. The DDC Customer Revenue Amount is defined as “the revenue BPA received from each customer under rates subject to the DDC since the beginning of the rate period, or since the last DDC, whichever is later.” *Id.* For those customers with a take-or-pay contracts that contain a provision that allows BPA to sell power which the customer elects not to take, BPA will attempt to sell the power. If BPA is able to sell the power and generates sufficient revenue so as to be made whole, the customer’s contractual obligation is satisfied. The satisfaction of the contractual obligation is different from eligibility for the DDC because the customer has not paid any revenue to BPA. Tr. 235. Customers’ eligibility for the DDC will be determined based on actual revenues paid to BPA.

### **Evaluation of Positions**

BPA’s position is that the DDC Customer Revenue Amount is the amount that the customer actually paid to BPA for power. Lefler, *et al.*, WP-02-E-BPA-77, Attachment A, at 33. If a customer did not take delivery of some of the power, the DDC Customer Revenue Amount will be the amount that customer actually paid to BPA. This is the appropriate amount upon which to

base a DDC rebate. The DDC Customer Revenue Amount does not include revenues BPA gets from selling power the customer does not take.

To compute the DDC payment based on revenues not received, for power not taken is inconsistent with one of the basic principles of DDC: that the amount a customer gets back is based on how much that customer has paid. Lefler, *et al.*, WP-02-E-BPA-73, at 37. This is the fundamental method chosen for allocating the DDC funds. If it is reasonable to distribute funds to only Northwest power customers on the theory that they are the regional entities that have contributed to the accumulation of the DDC surplus, then it makes sense to consider only amounts actually paid to BPA for power or liquidated damages when computing DDC payments.

### **Decision**

*BPA will apply the DDC to the amount a customer actually paid to BPA for power or liquidated damages, not for curtailed load for which the customer did not pay BPA.*

## **4.4 Implementation of Fish and Wildlife Funding Principles and Other Fish and Wildlife Issues**

### **Issue 1**

*Whether BPA's Supplemental Proposal ignores the Clean Water Act (CWA).*

### **Parties' Positions**

CRITFC/Yakama argue that BPA ignored the CWA in developing the Supplemental Proposal. They argue that the U.S. Army Corps of Engineers (Corps) dams violate water quality standards and that specific actions taken by the Corps affected these exceedences of state water quality standards. CRITFC/Yakama Brief, WP-02-B-CR/YA-02, at 9-11.

They contend that it is clear that the Corps will have to comply with water quality standards, yet BPA seems to be saying that determining compliance and implementation of those water quality standards will take years and there is no telling who will be responsible for funding those actions. *Id.* The tribes argue that BPA will be the agency largely responsible for funding the measures necessary to bring the Corps' dams into compliance with the CWA. *Id.*

NRU supports BPA's position that fish and wildlife costs are adequately covered in the Supplemental Proposal. NRU Ex. Brief, WP-02-R-NI-02, at 4.

### **BPA Staff Position**

BPA's position is that it has taken appropriate cognizance of the CWA. BPA's estimates of the potential costs to fish and wildlife are reflected in the 13 Fish and Wildlife Alternatives used in BPA's Risk Analysis Model (RiskMod) and ToolKit analyses. Lefler, *et al.*, WP-02-E-BPA-77, at 23. These 13 Alternatives also incorporate a wide range of fish and wildlife costs, including those related to the CWA. *Id.* at 25.

## **Evaluation of Positions**

In *National Wildlife Federation v. Army Corps of Engineers*, the court remanded the case to the Corps to issue a new decision replacing the 1998 Record of Decision which addresses its compliance with its legal obligations under the CWA. Lefler, *et al.*, WP-02-E-BPA-77, at 24. In response to the court's order and the National Marine Fisheries Service's new biological opinion issued on December 21, 2000, the Corps is preparing a new Record of Decision. *Id.* at 24-25.

The court did not order particular measures, nor did it order compliance – it ordered further addressing of compliance. *Id.* Identification of the particular measures to implement will be in the Water Quality Plan and implementation will take place over a period of years. *Id.* Once federal agencies decide to implement particular measures, the cost of these actions, and the schedule on which any actions will be implemented will be determined, taking into account all the necessary steps such as getting Congressional approval and the time it takes to construct the projects. *Id.* A determination will also be made regarding which agency is responsible for what funding. *Id.*

In the CRITFC/Yakama Brief, the parties argue that, especially in light of the direction in the *National Wildlife* opinion, the Corps will issue a new decision addressing compliance with its legal obligations under the CWA. BPA believes it must cover costs associated with meeting CWA responsibilities that are allocable to BPA. BPA and other federal agencies in the Pacific Northwest, including the Corps, Bureau of Reclamation, National Marine Fisheries Service (NMFS), and Environmental Protection Agency, have already determined that they will develop a water quality plan and progress toward meeting applicable water quality standards. BPA is an active participant in the federal agencies' development and implementation of a water plan and water quality measures. To allow for costs of improving water quality that may be allocable to BPA, BPA's rate case has already used a "keep the options open" approach intended to allow for varied levels of funding, given the uncertainty of costs and timing of measures. DeWolf, *et al.*, WP-02-E-BPA-13, at 7.

In preparing both the May Proposal and the Supplemental Proposal, BPA used 13 Fish and Wildlife Alternatives in its analysis in large measure "to establish a reasonable range of fish costs to be used for rate setting purposes, given the fact that decisions will not be made as to an actual alternative until after this rate proceeding." DeWolf, *et al.*, WP-02-E-BPA-39, at 29. The strategy was to use "a reasonable range within which decisions on system reconfiguration and related operations [could] be expected to fall." DeWolf, *et al.*, WP-02-E-BPA-13, at 9. The base rates BPA included in the May Proposal assumed this range of costs. This range includes alternatives with significant costs related to CWA measures, as well as alternatives related to breaching four Snake River Dams, high-cost alternatives which do not appear likely to be implemented within the FY 2002-2006 rate period. Therefore, BPA's risk analysis includes a wide range of costs for fish and wildlife activities. So, while BPA does not yet know what CWA-related costs might be, or for what portion of those costs BPA will have responsibility for, or what the timing of these costs will be, BPA is well-positioned to recover those costs.

Additionally, as noted *supra* in the Introduction to this chapter, BPA's Amended and Supplemental Proposals were intended to deal with the uncertainties surrounding the costs of

augmentation, while avoiding changes to base rates. BPA intends to rely on its robust risk mitigation tools such as the FB CRAC and the SN CRAC to deal with uncertainties such as fish costs, should the impact be adverse enough to trigger the CRAC mechanisms, rather than changing its base rates.

### **Decision**

*The Supplemental Proposal has adequately dealt with potential costs related to CWA implementation through the use of the 13 Fish and Wildlife Alternatives in its analysis, and the inclusion of the three-component CRAC.*

### **Issue 2**

*Whether BPA ignored the 2000 Biological Opinion (BO) in the Supplemental Proposal.*

### **Parties' Positions**

Both CRITFC/Yakama and NWECS/SOS argue that BPA ignored the 2000 BO in developing the Supplemental Proposal.

CRITFC/Yakama state that there is nothing on the record to substantiate BPA's claims that the cost to implement the 2000 BO will fall somewhere within the range of costs established by the 13 Fish and Wildlife Alternatives. CRITFC/Yakama Brief, WP-02-B-CR/YA-02, at 13. They also argue that BPA's estimates cannot be accurate, because the aggressive habitat and hatchery restoration effort called for in the Biological Opinion relies heavily on implementing habitat and hatchery actions by 2005, and include protecting or purchasing land and water. *Id.* CRITFC's estimates for all Biological Opinion Costs average almost \$400 million per year more than BPA has included in its base rate case analysis." *Id.* at 14.

CRITFC/Yakama also state that BPA says it is committed to an aggressive effort to implement the Biological Opinion but it does not know what will be done, when it will be done, who will implement it, or who will pay for it. *Id.* CRITFC/Yakama maintain that Bonneville has not addressed important costs and uncertainties about its future costs, that CRITFC/Yakama has provided detailed estimates of the cost of an aggressive effort to implement the Biological Opinion, and that there is no better information in the record. *Id.* at 15.

NWECS/SOS argue that BPA proposes to deliberately ignore significant new information about BO costs. NWECS/SOS Brief, WP-02-B-NA/SA-02, at 21, lines 7-9.

NRU agrees with BPA's draft decision that fish and wildlife costs are adequately covered in the Supplemental Proposal. NRU Ex. Brief, WP-02-R-NI-02, at 4.

### **BPA Staff Position**

BPA's position is that it has taken appropriate cognizance of the 2002 BO. Although the 2000 BO and Recovery Strategy have been released, and actions to be taken have been determined, implementation plans have not yet been completed. BPA's preliminary estimates of

the potential costs for fish and wildlife (other than those connected with hydro operations) related to the BO are within the range assumed in the 13 Fish and Wildlife Alternatives used in BPA's RiskMod and ToolKit analyses. Lefler, *et al.*, WP-02-E-BPA-77, at 23. These 13 Alternatives also incorporate a wide range of fish and wildlife costs. *Id.* at 25.

As explained in the May ROD, 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 be incurred 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.

May ROD, WP-02-A-02, at 5-28 to 5-29.

CRITFC has also developed estimates of BPA's costs related to the Biological Opinion. However, CRITFC's estimates are based on their assumptions about the time necessary to have an investment placed into service, and therefore become a repayment obligation, and the agencies responsible for these obligations. BPA believes CRITFC's estimates reflect unrealistic expectations in some categories. Lefler, *et al.*, WP-02-E-BPA-77, at 23-24.

### **Evaluation of Positions**

In preparing both the May Proposal and the Supplemental Proposal, BPA used the 13 Fish and Wildlife Alternatives developed as part of the Principles in its analysis, in large measure because there was no consensus among the participants in regional discussions as to which alternative was most likely to occur. As noted in the May ROD, the wisdom and merits of the Principles, including the 13 Fish and Wildlife Alternatives, are outside the scope of the rate case. May ROD, WP-02-A-02, at 2-7 to 2-9. The Principles were developed to establish a reasonable range of fish costs to be used for rate setting purposes, given the fact that decisions will not be made as to an actual alternative until after this rate proceeding. DeWolf, *et al.*, WP-02-E-BPA-39, at 29. The strategy was to use a range within which decisions on system reconfiguration and related operations could be expected to fall. DeWolf, *et al.*, WP-02-E-BPA-13, at 9. This range is included in the risk analysis included in this Supplemental Proposal.

BPA estimates the potential costs it will incur to implement the BO fall within the range of costs included in BPA's risk analysis. Lefler, *et al.*, WP-02-E-BPA-77, at 23, lines 12-15. The range of costs includes alternatives related to breaching four Snake River Dams, high-cost alternatives which do not appear to be likely to be implemented within the FY 2002-2006 rate period.

Therefore, BPA's risk analysis includes a wide range of costs for fish and wildlife activities. BPA believes CRITFC's estimates reflect unrealistic expectations in some categories, particularly for activities that will occur in FYs 2001 and 2002. *Id.* at 23-24. Their assumptions include both higher funding levels than BPA believes are necessary to implement activities, and faster implementation timelines than BPA believes are likely. *Id.* These assumptions can have the effect of showing much more cost to BPA much sooner than BPA believes will occur. *Id.* CRITFC's estimates have not been validated by BPA or other federal agencies. *Id.* The cost estimates BPA has developed represent a reasonable judgement of the activities BPA will undertake to meet its Endangered Species Act and Northwest Power Act fish and wildlife responsibilities, and the schedule for implementation. *Id.* No consensus currently exists on schedule, level of costs, or who will be obligated for which costs. *Id.*

So, while the costs related to the BO have not been determined, and BPA does not know what portion of those costs will be BPA's responsibility, or what the timing of these costs will be, BPA's proposal positions BPA to recover those costs.

As noted *supra* in the Introduction to this chapter, both the Amended and Supplemental Proposals were intended to deal with the uncertainties surrounding the costs of augmentation, while avoiding changes to base rates. BPA's proposal includes a robust risk mitigation package, with a broad range of potential fish and wildlife costs and a three-component CRAC. BPA's Supplemental Proposal is designed to recover, with a high probability, potential implementation costs of the BO. BPA would not intend to address unexpectedly high costs by recalculating base rates for the FY 2002-2006 period, but would deal with the impacts on financial reserves through the use of the FB CRAC and/or the SN CRAC should the impact be adverse enough to trigger these CRAC mechanisms.

### **Decision**

*The Supplemental Proposal has adequately reflected the BO through the use of the 13 Fish and Wildlife Alternatives in its analysis. The FB CRAC and SN CRAC are available if necessary to recover higher implementation costs.*

### **Issue 3**

*Whether the potential magnitude of future fish and wildlife or CWA costs is such that BPA's Supplemental Proposal fails to provide sufficient funds to meet its total system costs and assure Treasury repayment.*

### **Parties' Positions**

CRITFC/Yakama argue that BPA must adequately establish rates to recover its costs and expenses incurred by the Administrator pursuant to the Northwest Power Act and other provisions of law. 16 U.S.C. § 839e(a)(1). Because BPA's total system costs are subject to future events, inherent in these costs are risks that must be quantified and addressed in BPA's rates. CRITFC/Yakama Brief, WP-02-B-CR/YA-02, at 7, lines 14-18.



CRITFC/Yakama argue that BPA has existing unmet fish and wildlife commitments; *id.* at 6, lines 18-19; assumes significant additional fish and wildlife costs will not materialize, *id.* lines 16-17, ignores information contained in the 2000 BO and a recent court case determining the Corps' responsibility under the CWA for the lower Snake River Dams, *id.* at 8; has failed to address the significant risk that fish and wildlife implementation costs will be substantially higher than BPA has assumed in the rate case, *id.* at 15, lines 18-20; and has failed to address the risk of failure to fully implement the BO, *id.* at 15, lines 20-21. Therefore, they argue the Supplemental Proposal is unlikely to meet its costs and does not assure Treasury repayment. *Id.* at 7, lines 10-11.

The JCG states that the proposed risk mitigation tools are adequate to ensure BPA's fiscal health over a broad range of potential circumstances. JCG Brief, WP-02-B-JCG-01, at 9. They also argue that the risk mitigation tools are an integrated package that will provide BPA with a broad range of risk mitigation tools designed to address specific risks BPA is likely to face in the rate period. *Id.* JCG further argues that these tools are sufficiently flexible to deal with circumstances that may not currently be foreseen, and the package of risk mitigation tools provides a very high probability that BPA will be able to fulfill its service obligations to regional customers, while meeting its payment obligations to the Treasury and other creditors. *Id.* at 10.

WPAG states that the combination of the LB, FB, and SN CRACs, and the revised DDC, gives BPA a high degree of assurance that it will be able to pay the Treasury and its other creditors on time and in full. WPAG Brief, WP-02-B-WA-01, at 6.

NRU agrees with BPA's proposal that fish and wildlife costs are adequately covered in the Supplemental Proposal. NRU Ex. Brief, WP-02-R-NI-02, at 4.

### **BPA Staff Position**

The 2000 BO and Recovery Strategy have been released, and actions to be taken have been determined, however, implementation plans are not yet complete. BPA's estimates of the potential costs for fish and wildlife (other than those connected with hydro operations) related to the BO are within the range assumed in the 13 Fish and Wildlife Alternatives used in BPA's RiskMod and ToolKit analyses. Lefler, *et al.*, WP-02-E-BPA-77, at 23. (*See also* Issue 2 *supra.*)

BPA's Supplemental Proposal, which incorporates the 13 Alternatives used during the development of the Principles, already accommodates a wide range of fish and wildlife costs, including CWA-related costs. Whether the CWA lawsuit results in costs to BPA in excess of this range during the FY 2002-2006 rate period cannot be known at this time. *Id.* at 25, lines 7-11. (*See also* Issue 1 *supra.*)

### **Evaluation of Positions**

BPA does not attempt to model every conceivable type of risk it faces. In BPA's Risk Analysis Study, BPA identifies key risks. *See* WP-02-FS-BPA-03, at 1, line 18. Some types of risk are not appropriate to be modeled, such as risks for which appropriate responses are in place. Some

risks are such that they cannot be modeled. Further, some of the “risks” that are not modeled are upside risks that would benefit BPA, such as bond refinancings. BPA may pursue refinancings in the future when conditions are such that BPA would benefit financially. Such beneficial risks have never been included in the risk modeling. The fact that some risks to BPA are not being modeled, some of which would benefit BPA and some of which would not, does not in itself demonstrate that BPA’s proposal has an insufficient TPP. *Id.* at 27, lines 3-12.

Spending for fish and wildlife has been lower than expected under the MOA primarily due to lower Congressional appropriations than expected under the MOA and because the Corps has placed less investment in service than forecast under the MOA. May ROD, WP-02-A-02, at 7-45. BPA continues to fund projects recommended by the Northwest Power Planning Council.

The Principles reaffirmed BPA’s commitment to a high probability of timely repayment to the Treasury. The Principles also acknowledged the impossibility of achieving a 100 percent probability of timely repayment. *See* Section 5.4, May ROD, WP-02-A-02.

BPA is including a wide range of fish and wildlife costs in its analysis, and believes its potential costs are within the range of costs included in its risk modeling. Lefler, *et al.*, WP-02-E-BPA-77, at 23. BPA’s total risk mitigation package is more robust than that included in the May Proposal. *Id.* The SN CRAC provides significant protection against high, unexpected costs. *Id.*

It appears that CRITFC/Yakama would like BPA to treat some potential costs, particularly those associated with the CWA and the 2000 BO, as known and certain costs, and to accept the figures presented by CRITFC/Yakama for the magnitude of those costs. BPA is treating those costs as risks, since they are presently uncertain: the size and timing of those costs, and how much BPA will need to cover during the FY 2002-2006 rate period are currently unknown. Lefler, *et al.*, WP-02-E-BPA-77, at 22 to 26.

### **Decision**

*BPA’s proposal appropriately includes representations of potentially large costs for fish and wildlife and for CWA measures as risks rather than as certain costs. BPA’s proposal provides for sufficient recovery of all costs, including potential fish and wildlife costs, with an 80-88 percent probability of paying Treasury on time and in full in accordance with BPA’s long-standing probabilistic approach to cost recovery.*

### **Issue 4**

*Whether the SN CRAC is needlessly flawed and in direct conflict with policies adopted by BPA enabling it to declare a hydro emergency, thereby placing an excessive burden on fish for fixing emergencies, and therefore BPA should change the look-ahead period for the SN CRAC to a rolling 12-month period and change the threshold for triggering the SN CRAC to a probability of 20 percent or greater of exhausting cash reserves.*

## **Parties' Positions**

NWEC/SOS make several new arguments in their initial brief regarding the criteria used to trigger the SN CRAC. Generally, they argued that: (a) the need for consistency between the SN CRAC and the power system emergency criteria require changes in the SN CRAC; and (b) BPA's rate case and other plans (*i.e.*, the FY 2001 power system emergency criteria) together place an unfairly great burden on fish for dealing with financial emergencies, and therefore the SN CRAC should be changed. However, several parties argue that (c) there are many reasons to retain BPA staff's proposed terms for the SN CRAC.

Specifically, CRITFC/Yakama argue that the SN CRAC should trigger using a 12-month forward looking forecast similar to Bonneville's emergency declaration measures. CRITFC/Yakama Brief, WP-02-B-CR/YA-02, at 50. All financial and operational measures should be exhausted before declaring an emergency and operating the river to the detriment of salmon. *Id.* The rationale for this proposed change is contained in CRITFC/Yakama's assertion that BPA's standards for financial and fish emergencies discriminate against fish. CRITFC/Yakama argue that, by not using a forecast that goes beyond the fiscal year, BPA is limiting its ability to trigger its SN CRAC. *Id.* On the other hand, the proposed FCRPS criteria in the March 30 federal principles allow an emergency to be declared based on a forecast of expected financial obligations over the succeeding 12 months. Sheets, *et al.*, WP-02-E-CR/YA-06. If, due to cash flow difficulties or any other foreseeable problem, BPA forecasts that it would exhaust its cash reserves even a few months into the next fiscal year, BPA could not trigger the CRAC, but would be forced to declare a power system emergency. *Id.* at 22.

This argument was also put forth by NWEC/SOS in their initial brief. NWEC/SOS Brief, WP-02-B-NA/SA-02, at 14-15. NWEC/SOS argue that, since BPA evidently believes that a 12-month forecast and a 20 percent threshold are important enough bases upon which to declare a hydro emergency, one must conclude that BPA will need the same sort of protection in the future, therefore BPA must create an SN CRAC which "works in conjunction with, not inferior to, that need." NWEC/SOS Ex. Brief WP-02-R-NA/SA-02, at 11.

CRITFC adopts by reference the arguments put forth by NWEC/SOS on this issue in their brief on exceptions. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-02, at 5.

### **(a) Consistency**

NWEC/SOS argue that the power system emergency criteria adopted during FY 2001 and the SN CRAC are similar in nature, and that therefore they must be "consistent" with each other. NWEC/SOS Brief, WP-02-B-NA/SA-02, at 20-21. They assert that the two mechanisms are inconsistent. The SN CRAC in BPA's Supplemental Proposal will trigger when BPA misses a payment to the Treasury or any other creditor, or when the probability of missing any such payment in any of the remaining months in the current fiscal year rises above 50 percent. According to the criteria adopted by the federal agencies for FY 2001, a power system emergency will be declared when the probability of exhaustion of BPA's cash rises to 20 percent

or higher in any of the next 12 months. The following table illustrates the inconsistency of the two mechanisms that NWEC/SOS assert must be resolved:

	SN CRAC	Power System Emergency
Look-ahead period	remainder of current FY	rolling 12 months
Trigger if probability of exhausting cash reserves in any month goes above	50 percent	20 percent

Similarly, CRITFC/Yakama argue that BPA should change its proposed SN CRAC trigger mechanism to include a 12-month forecast similar to that used to declare a financial emergency, and that the SN CRAC should trigger long before and to the maximum extent possible before the declaration of a financial emergency and curtailment of operations to protect salmon. CRITFC/Yakama Brief, WP-02-B-CR/YA-02, at 23, lines 25-29.

**(b) Fairness**

NWEC/SOS argue that the inconsistency they asserted means that BPA will lean on fish too hard, to the unfair benefit of ratepayers, and that BPA has essentially elevated Treasury payment to its highest priority, contradicting BPA’s statements. They argue that since a worsening of BPA’s financial condition, that is, a rising probability of exhaustion of cash, would meet the power system emergency’s 20 percent trigger before it met the SN CRAC’s 50 percent trigger, fish are being leaned on first. Further, they argue, the Treasury payment is being elevated to the highest position in BPA’s priorities since the power system emergency could trigger before the SN CRAC. NWEC/SOS Ex. Brief, WP-02-B-NA/SA-02, at 14 and 16.

CRITFC/Yakama also argue in their brief on exceptions that BPA should accord a higher priority to all of its fish and wildlife obligations than to BPA’s Treasury payment obligations. Similarly, NWEC/SOS argue that since the power system emergency criteria look ahead 12 months and the SN CRAC only looks ahead through the remainder of the current fiscal year, a power system emergency could be triggered by financial forecasts within the next 12 months but outside the scope of the SN CRAC’s forecast, again causing fish to bear the burden of responding to emergencies before ratepayers must bear such a burden. They argue this is unfair, and constitutes inequitable treatment of fish. NWEC/SOS Brief, WP-02-B-NA/SA-02, at 14. They contend that since the financial criterion for an emergency declaration is triggered by a 12-month rolling forecast, and BPA’s proposed SN and FB CRACs can only look out to the end of the existing fiscal year, BPA could be precluded from triggering these two CRACs if a problem is forecast to hit after the end of the fiscal year. *Id.* The agency will instead declare a financial emergency and lean on fish operations to get through the problem. *Id.* BPA therefore violates its own policy in setting rates, because Treasury payment will no longer be a lower priority than its fish and wildlife obligations. *Id.*

In their brief on exceptions, NWEC/SOS state that “BPA should not be allowed, in this proceeding to constrain its main mitigation tool—the SN CRAC—so that it will specifically not be reliably available, thus forcing the region to rely upon a hydro emergency to solve its financial problems. NWEC/SOS Ex. Brief, WP-02-R-NA/SA-02, at 10.

CRITFC/Yakama claim that BPA is using its ability to declare a “financial emergency” as evidence that it can meet its obligations under the ESA. CRITFC/Yakama Brief, WP-02-B-CR/YA-02, at 21. They argue that BPA can set its rates too low to cover its needs and then simply declare a financial emergency to run the river harder and kill more salmon, or refuse to trigger a CRAC, or a large enough CRAC, and instead rely on its ability to declare a fish emergency. *Id.*

They claim that a SN CRAC with a 12-month forecast trigger mechanism that operates before the declaration of a fish emergency provides them the fairness they seek. *Id.* at 23. In their brief on exceptions, CRITFC/Yakama adopt by reference the arguments put for by NVEC on this issue in their brief on exceptions, WP-02-R-NA/SA-02, and state that under BPA’s current proposal, salmon are the shock absorber for poor planning. CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-02, at 5.

**(c) Retain proposed terms**

NRU, WPAG, and JCG argue that the issue was not raised timely. NRU Ex. Brief, WP-02-R-NI-02, at 5; WPAG Ex. Brief, WP-02-R-WA-02, at 2-3; JCG Ex. Brief, WP-02-R-JCG-02, at 4. BPA’s proposal contains sufficient flexibility. NRU Ex. Brief, WP-02-R-NI-02, at 5; JCG Ex. Brief, WP-02-R-JCG-02, at 7. Changing the probability standard for the SN CRAC from 20 percent to 50 percent would further increase rate volatility. NRU Ex. Brief, WP-02-R-NI-02, at 6. Using a 12-month forecast period would result in setting rates on the basis of expectations of costs outside the rate period. NRU Ex. Brief, WP-02-R-NI-02, at 5; JCG Ex. Brief, WP-02-R-JCG-02, at 9. Changing either the probability standard or the forecast period for the SN CRAC would alter the delicate balance of elements in the Partial Stipulation and Settlement Agreement. NRU Ex. Brief, WP-02-R-NI-02, at 6. The SN CRAC is designed for a different need from that addressed by the power system emergency. JCG Ex. Brief, WP-02-R-JCG-02, at 8. Additionally, WPAG and JCG argue that changing the SN CRAC terms would not resolve the objections of NVEC/SOS and CRITFC/Yakama to the power system emergency criteria. WPAG Ex. Brief, WP-02-R-WP-02, at 3; JCG Ex. Brief, WP-02-R-JCG-02, at 9-10.

NRU supports BPA’s position that a declaration of a system emergency is not an issue in this rate proceeding. NRU Ex. Brief, WP-02-R-NI-02, at 4. They also see no reason to move the SN CRAC threshold to 20 percent, or to adopt the proposal for a rolling 12-month period. *Id.* at 5. For the following five reasons, NRU recommends that this idea be discarded: first, this concept was raised too late in the process to allow opportunity to develop a record on the proposal, and adoption of the proposal would not provide the parties adequate opportunity for refutation or rebuttal, *id.* at 5; second, the unprecedented nature and flexibility of adjustment clauses in the proposal give BPA sufficient mechanisms to address the financial risks it faces, *id.* at 6; third, a 20 percent SN CRAC threshold would yield a significantly greater amount of rate volatility than will be experienced under the already volatile proposal, and this is unnecessary, *id.* at 6; fourth, using a rolling 12-month forecast could result in BPA setting rates for the rate period based on expectations for costs outside the rate period, which is inconsistent with standard ratemaking practice, *id.*, and fifth, adoption of this concept would fundamentally alter and undermine the delicate alliance reflected in the Partial Stipulation and Settlement Agreement, *id.* “BPA should

discard the untimely and unacceptable proposal to adjust the 50 percent probability or the window of time for the forecast.” *Id.* at 7. Canby also believes the Administrator should reject the rolling 12-month period as well as the adjustments to the trigger from 50 percent probability. Canby Ex. Brief, WP-02-R-CA-02, at 31.

WPAG argues that the changes proposed by NWECS/SOS and CRITFC/Yakama have not been submitted timely, and by raising substantive issues for the first time in their initial briefs, those parties have deprived the other parties of their procedural rights. WPAG Ex. Brief, WP-02-R-WA-02, at 2-3. They also argue that the proposal to alter the operation of the SN CRAC will not resolve the objections of NWECS/SOS and CRITFC/Yakama to the power system emergency criteria, and is not an action justified by the record in this proceeding. *Id.* at 3. Implementing the proposal “will not only disrupt the operation of the SN CRAC as negotiated by the parties, it will also conflict with the operation of the FB CRAC and the DDC.” *Id.* at 4.

JCG argue that the proposal of NWECS/SOS to revise the trigger point and the forecast period of the SN CRAC has not been timely raised, thus “depriv(ing) all other rate case parties of the opportunity to conduct discovery, to evaluate the possible effects of the proposal, to offer their own expert testimony in rebuttal, and to subject the NWECS, SOS, CRITFC, and Yakama witnesses to cross-examination on this proposal.” JCG Ex. Brief, WP-02-R-JCG-2, at 4. JCG goes on to argue that the NWECS/SOS offers no compelling reason for altering the 50 percent probability other than the fact that the SN CRAC trigger point differs from that used in the power system emergency criteria, and that the NWECS/SOS recommendation ignores the package of risk mitigation measures within which the SN CRAC is designed to operate, and fails to consider the purpose that the SN CRAC is designed to serve. *Id.* at 7. “The SN CRAC and the power system emergency criteria serve fundamentally different purposes, and the use of different criteria has not been shown to jeopardize either BPA’s financial position or its ability to fulfill its fish mitigation obligations.” *Id.* at 8.

Additionally, JCG argues that, for several reasons, the forecast period for the SN CRAC should not be altered. *Id.* at 8. First, since the SN CRAC can be triggered on the basis of forecast events and contains no limits on the magnitude of the increase that may be imposed, use of a fiscal year forecast period addressed a concern that the SN CRAC not be triggered based on speculative future events. *Id.* Second, the fiscal year forecast period is consistent with the time frames used in the other elements of the risk package, *i.e.*, the FB CRAC and the DDC. *Id.* at 8-9. At a minimum, JCG argues, arbitrarily placing the SN CRAC on a rolling 12-month time frame would necessitate revisiting the time frames for the operation of the FB CRAC and the DDC. *Id.* at 9.

Third, the rolling 12-month forecast proposed by CRITFC/Yakama and NWECS/SOS also would have BPA set rates for the rate period based on expectations for costs outside the rate period, which is inconsistent with standard ratemaking practice. *Id.* at 9. Finally, the 12-month forecast proposal does not address the concerns raised by CRITFC/Yakama and NWECS/SOS. *Id.* at 9-10.

## **BPA Staff Position**

This set of issues was raised first in cross-examination, then in initial briefs. No party filed any direct or rebuttal testimony on these issues, and that makes it difficult for BPA to develop a record for considering it. BPA will argue the issue as if it had been presented in testimony.

### **(a) Consistency**

There is no reason why the numerical parameters for the SN CRAC and the power system emergency need to be identical. The two measures were developed to mitigate different risks. The power system emergency criteria are not a rate case matter, and do not apply to the period for which this proceeding is establishing rates. *See* Section 2.7 of this ROD.

### **(b) Fairness**

BPA has not changed its priority of payments; it pays Treasury last. The power system emergency criteria do not simply help ratepayers at the expense of fish—they also work to protect financial obligations for fish and wildlife programs and to keep the lights on. BPA’s proposal does not place excessive or inequitable burdens on fish.

## **Evaluation of Positions**

CRITFC/Yakama and NWECS/SOS both argue that there is a need for consistency between the criteria for a power system emergency and the triggering of the SN CRAC. The primary arguments are that the SN CRAC should trigger using a 12-month forward looking forecast similar to BPA’s emergency declaration measures and that the trigger of 50 percent probability of exhausting cash reserves with the SN CRAC and 20 percent with the emergency declarations are unfair.

### **(a) Consistency**

The comparison asserted by NWECS/SOS is faulty for several reasons.

First, the power system emergency criteria are not a rate case matter, and were developed outside the rate case. *See supra* Section 2.7.

Second, the power system emergency criteria apply to FY 2001. *See* Exhibit WP-02-E-CR/YA-19, “Federal Agency’s Criteria and Priorities for 2001, FCRPS Operations, March 30, 2001.” There is no SN CRAC in FY 2001. BPA’s proposed SN CRAC applies to FY 2002 through 2006, and there are no power system emergency criteria developed yet for those years.

Third, the two mechanisms have been designed to respond to entirely different problems. JCG Ex. Brief, WP-02-R-JCG-2, at 8. The SN CRAC is designed to—in fact, was proposed by NWECS/SOS in order to—reduce the risk of the second of two Treasury deferrals in a row. Lefler, *et al.*, WP-02-E-BPA-77, at 20, lines 1-4. The power system emergency criteria, by contrast, were developed to deal with very short-term cash and reliability problems, specifically,

near-record low water combined with record high electricity prices. This combination in FY 2001 meant that provision of the full spill program called for in the 2000 BO would have required BPA to purchase power in the record-high market, which would have exhausted BPA's cash, which would have prevented BPA both from meeting its power delivery obligations and from meeting its funding obligations for fish and wildlife measures.

As originally suggested by NWECS/SOS, the SN CRAC would be triggered by a miss of BPA's annual Treasury payment (*i.e.*, the September 30 payment). If that were still the SN CRAC trigger, it would be difficult to draw a parallel to the power system emergency criteria. To suggest that the SN CRAC criteria is unfair to fish now that the threshold has been liberalized, making it easier for BPA to "lean on" ratepayers, simply is unsupported by the record.

Power system emergencies are declared to deal with a short-term problem, *i.e.*, less than a year. The SN CRAC, once it triggers, allows for a re-setting of the parameters of the FB CRAC. Because those parameters cover a broad range, it would be highly optimistic to assume that the SN CRAC 7(i) rate-setting process would be concluded in less than 90 days. The hearing itself is to be completed in 40 days, unless the parties agree to a different duration. Lefler, *et al.*, WP-02-BPA-77, Attachment A, at 31. The process lengthens by adding another 60 days minimum for FERC approval, another 30 days for customers to incur the costs under the new rates, and another 30 days before the bill is due. Under the most optimistic assumptions, the SN CRAC would start collecting revenues six to seven months after it triggers. Therefore this proposed change may be well intentioned, but in reality would not change the SN CRAC from its original intent of preventing a second deferral.

Fourth, the standards are not quite as similar as NWECS/SOS suggested. The power system emergency criteria use the probability of BPA's cash actually being exhausted. *See* Exhibit WP-02-E-CR/YA-19, page 2, referenced in Cross Transcript page 158, line 16. The SN CRAC is triggered by the probability of BPA missing a payment to Treasury or another creditor. Lefler, *et al.*, WP-02-E-BPA-77, Attachment A, at 30. BPA would unavoidably miss payments to other creditors if it exhausted its cash, so this standard is parallel to the power system emergency standard. However, BPA's position with regard to Treasury payments has always been that BPA must maintain some working capital, and so it would defer Treasury payments while still preserving some cash. Thus, one of the two triggers for the SN CRAC is a forecast of low cash, while the trigger for the power system emergency is a forecast of exhausting cash reserves.

Finally, the right comparison is between BPA's obligations to and expectations of ratepayers and its obligations to and expectations of fisheries interests, not between the SN CRAC and the power system emergency criteria. The rate case includes: the base rates described in the May Proposal; the LB CRAC, FB CRAC, and SN CRAC, which can be recalculated every six months, every year, and whenever appropriate, respectively; beginning 2002 reserves; high expected ending 2006 reserves; and a high TPP. BPA's fish and wildlife commitments include: the Principles; unprecedentedly high levels of funding; the 2000 FCRPS BO (which includes a provision for emergency declarations); beginning FY 2002 reserves; a high probability that ending FY 2006 reserves will be at least \$500 million; and a higher priority for funding fish measures than for BPA's payments to the Treasury. This larger context requires an appropriate balance; numerical consistency between the two components is not necessary.



**(b) Fairness**

First, BPA has modeled its working capital requirements as \$50 million in the rate case. (*See* Section 4.5, Issue 3 *supra* for parties' suggestion that this modeling assumption be changed.) BPA holds that its cash management practices are not rate case matters, though modeling of those practices may be rate case issues. As part of its cash management planning, BPA may decide that it is imprudent to allow payments to Treasury at the end of September to reduce cash below a year-end level that is higher than \$50 million. Suppose the figure were \$300 million. BPA might at some time during a fiscal year forecast that the probability of year-end cash being below \$300 million, after paying Treasury, to be more than 50 percent, meaning that there is a probability above 50 percent of missing part of the Treasury payment in order to preserve the \$300 million in cash. This would trigger the SN CRAC, even though the probability of exhausting cash reserves may not have exceeded 20 percent in any month; that is, the power system emergency may not have triggered.

Second, the power system emergency is not a simple mechanism to save ratepayers at the expense of fish. If BPA were to run out of cash, the consequences would be very serious. Reliability would be jeopardized, as power providers are reluctant or unwilling to deliver power to buyers who are unable to pay, as California has seen this year. If BPA ran out of cash, it could not pay all of its vendors, and contractors implementing parts of the federal fish and wildlife programs could be among the vendors who would not be paid.

Third, the way in which the power system emergency "leans on" fish is to propose modifications in river operations, not changes in funding. Such changes to preserve reliability are expressly allowed by provisions in the 2000 BO. The SN CRAC, on the other hand, operates to actually collect more revenue from ratepayers. Neither mechanism restricts BPA's funding of fish and wildlife measures. Any reduction in financial benefits—either a decrease in funding provided or an increase in revenues collected—would affect ratepayers through triggering of the SN CRAC before it would affect fish and wildlife programs through default on payment obligations.

Fourth, BPA's payments to Treasury remain its lowest-priority financial obligations, as BPA has always stated. NWECC/SOS appear to have erroneously taken BPA's priority of payments, which is a payment sequencing policy, for an expression of overall agency priorities. CRITFC/Yakama stated, "Bonneville has repeatedly stated in testimony and to the tribes that it would fund all of its fish and wildlife obligations before paying Treasury." CRITFC/Yakama Ex. Brief, WP-02-R-CR/YA-02, at 5. That is correct: that is a statement about funding. BPA would defer its Treasury payment before reducing contracted payments for fish and wildlife expenses. (While a significant fraction of BPA's Treasury payment goes to repay investment in fish and wildlife programs, a deferral of this repayment cannot reduce the fish and wildlife funding – that funding had been provided previously and is now to be repaid.) The placement of payments to Treasury at the end of the prioritized list of payments does not imply that repaying Treasury is the least-important of BPA's tasks, requirements, and obligations. BPA's priority of payments describes the priorities of payments, not the priority of the entire, diverse set of the Administrator's obligations. The priority of payments is based on the repayment policy, which itself is largely based on RA 6120.2. Revenue Requirement, May Proposal Study, WP-02-FS-BPA-02, at 64-65. In particular, RA 6120.2 states:

Priority of Revenue Application. Annual revenues will be first applied to the following recovery of costs during the year in which they are incurred: operation and maintenance (O&M), purchased and exchange power, transmission service and other, and interest expense and any appropriation amortization of revenue bonds. RA 6120.2 at 5.

It is clear that this guidance is referring to payments, not to all obligations.

Fifth, there are many different ways in which fish or power interests can be affected by external events. The winter of 2000 – 2001 is proving to be one of the driest on record in the Columbia drainage area. This has negative effects on both fish and power ratepayers. Before BPA declared a power system emergency this year, it had already spent hundreds of millions of dollars more than expected buying power in a record-high market, draining cash reserves and considering whether the FB CRAC for FY 2002 will trigger. The extremely high prices this year have meant that the spill program, originally envisioned as having an actual or opportunity cost of a couple hundred million dollars would actually have a cost of a couple billion dollars. Ratepayers were already affected before the power system emergency was declared.

Finally, BPA will not “lean on” fish first. There may be circumstances in which the FB CRAC or SN CRAC would trigger, due to sudden and large expenses, but a power system emergency is not declared because water is plentiful and/or power is cheap.

While the fact that both the SN CRAC and the power system emergency criteria both have probabilities and look-ahead criteria makes it tempting to compare the two directly, each is only a part of a much larger context, and they were designed to deal with different problems. The appropriate context for comparison is larger than the numerical details of the SN CRAC and the power system emergency criteria and includes the other CRACs, BPA’s priority of payments, the entirety of BPA’s power contracts and its power rate case, and all of BPA’s Fish and Wildlife commitments and obligations. Given this larger context of rate case features and Fish and Wildlife provisions (both within and outside the rate case), there is no reason why the SN CRAC and the power system emergency criteria need to be identical.

The larger context reveals that the balance between fish and power interests in BPA’s rate proposal and other arenas, such as the development of the power system emergency criteria, is highly multidimensional, much more complex than can be shown by comparing the SN CRAC with the power system emergency criteria. BPA is confident that its rate proposal has struck a reasonable and prudent balance, and does not lean excessively on fish.

**(c) Retain proposed terms**

The suggestions to change the terms of the SN CRAC were raised too late in the process to allow opportunity to develop a record on the proposal, and adoption of the proposal would not provide the parties adequate opportunity for refutation or rebuttal. NRU Ex. Brief, WP-02-R-NI-02, at 5; WPAG Ex. Brief, WP-02-R-WA-02, at 2-3; JCG Ex. Brief, WP-02-R-JCG-02, at 4.

BPA's proposal contains adequate flexibility to address the financial risks it faces. NRU Ex. Brief, WP-02-R-NI-02, at 5. Changing the SN CRAC terms would fundamentally alter and undermine the balance reflected in the Partial Stipulation and Settlement Agreement. *Id.* at 6.

### **Decision**

*The SN CRAC is not in conflict with the power system emergency criteria.*

*Within the larger context in which these two mechanisms operate, BPA has created a reasonable and prudent balance among many interests, including fish and ratepayers. BPA's rate proposal is not unfair to fish. Suggestions to change the SN CRAC were not made in a timely manner. Changing the SN CRAC parameters would upset the balance of the Partial Stipulation and Settlement Agreement. The parameters of the SN CRAC will not change.*

## **4.5            Modeling Issues**

### **Issue 1**

*Whether the ToolKit Model fails to take into account load loss when calculating the maximum annual amount of FB CRAC revenue that can be generated.*

### **Parties' Positions**

In its initial brief, SUB notes that in its rebuttal testimony, SUB had pointed out a number of inconsistencies with the ToolKit model, including the assertion that the Toolkit does not correctly measure the impact of buy downs or load loss to other customers to account for CRAC mechanisms being recovered over a smaller amount of sales. SUB Brief, WP-02-B-SP-02, at 8-9.

### **BPA Staff Position**

SUB raised this issue in its rebuttal testimony, thereby denying BPA staff and other parties an adequate opportunity to develop a record. The ToolKit employed in BPA's Supplemental Proposal contained the error described by SUB, except that in FY 2002 the FB CRAC maximum revenue is not prorated for Slice load. In the other years, the maximum FB CRAC revenue is less than or equal to \$175 million, so the impact of the error is to overstate the amount of FB CRAC revenue by (71.1 percent - 65 percent) \* \$175 million, or a little under \$11 million. This amount is small enough that it is unlikely to have had a significant impact on TPP. The error will be corrected.

### **Evaluation of Positions**

BPA agrees that there is an error and that it should be corrected in the final studies.

### **Decision**

*The ToolKit contained an error that will be corrected in final studies.*

## **Issue 2**

*Whether the ToolKit Model fails to account for the LB CRAC true-up and whether BPA should provide a remedy.*

### **Parties' Positions**

In its initial brief, SUB notes that in its rebuttal testimony, it had pointed out a number of inconsistencies with the ToolKit model, including the assertion that ToolKit does not model the LB CRAC adjustment every six months though it is capable of modeling true-up adjustments under different CRAC proposals. SUB Brief, WP-02-B-SP-02, at 8.

SUB argues that correcting this omission might increase TPP. *Id.* SUB argues that BPA remedy this by either providing a semi-annual review of the LB CRAC or by correcting the ToolKit and presenting the changes in a brief public process. *Id.* at 9.

### **BPA Staff Position**

SUB raised this issue in its rebuttal testimony, thereby denying BPA and other parties an adequate opportunity to develop a record on this matter. BPA modeled the LB CRAC in the ToolKit and RiskMod by assuming that the entire augmentation quantity would be purchased in advance at a price equal to the mean of the distribution of prices for each of the three market scenarios. This left no remaining augmentation need to be priced by forward prices and trueed up with actual spot prices. The only true-up that would still operate in this case is a true-up for load. There does not appear to be any reason to assume that the true-up for load would result in an increase rather than a decrease, or vice versa, so while this effect was omitted, there does not appear to be any bias that results from the omission. Including the LB CRAC true-up could add some volatility to the LB CRAC revenues, but there is no reason to think that the expected values would change.

### **Evaluation of Positions**

SUB has asserted that incorporation of the LB CRAC true-up could affect TPP more in higher-priced games than in lower-priced games, and that this is a potential bias that should be corrected. Nelson, WP-02-E-SUB-03, at 9–10. BPA has indicated that its modeling included an assumption that no augmentation need would be priced at spot market prices, and therefore the dynamic suggested by SUB would not be in effect. There is no evidence that omitting the LB CRAC true-up has resulted in a consistent bias; the expected values of LB CRAC revenues are unlikely to change.

### **Decision**

*The LB CRAC true-up need not be modeled in ToolKit.*

### **Issue 3**

*Whether the \$50 million working capital assumption in the ToolKit should be modified.*

#### **Parties' Positions**

In its initial brief, SUB alleges a number of inconsistencies in the ToolKit model, including the assertion that ToolKit artificially sets a lower annual reserve limit of \$50 million in its model runs and under-reports the frequency of the FB CRAC as a result. SUB Brief, WP-02-SP-B-02, at 8.

In its brief on exceptions, however, SUB argues that there is evidence that BPA's working capital needs are actually \$300 million, and that therefore BPA errs in not setting the floor in the ToolKit at \$300 million. The consequence of this error, SUB asserts, is that BPA has overstated the actual TPP. SUB Ex. Brief, WP-02-R-SP-02, at 7.

NWEC/SOS and CRITFC/Yakama argue in their initial briefs that BPA has stated that it actually needs more than \$50 million in working capital during some parts of the year to maintain liquidity. Therefore, they argue, the modeling assumption in the ToolKit that only \$50 million need be retained is flawed and should be changed to a higher figure.

NWEC/SOS note that when BPA established the TPP policy in the 1993 rate case, it also established a minimum working capital level for use in determining the TPP. NWEC/SOS, WP-02-B-NA/SA-02, at 6-7. They argue that since this level was determined after much discussion of BPA's monthly cash needs including alternative proposals by the Joint Customers, monthly cash needs are a rate case issue. *Id.* BPA could accommodate much of the problem of this risk by raising the threshold in the Toolkit for calculation of TPP from the present \$50 million to a more satisfactory figure of about \$300 million. *Id.*

In their brief on exceptions, NWEC/SOS contend that, by failing to model \$300 million in working capital, and instead relying on "non-existent credit line," the rate proposal has a TPP of less than 80 percent. NWEC/SOS Ex. Brief, WP-02-NA/SA-02, at 3.

CRITFC/Yakama argue that "the \$50 million level currently used in the rate case (to calculate TPP) must be raised to more realistic levels or other short-term financing be in place." CRITFC/Yakama Brief, WP-02-B-CR/YA-02, at 23.

NRU supports BPA's proposal that the monthly cash management is not a rate case issue. NRU Ex. Brief, WP-02-NI-R-02, at 4.

#### **BPA Staff Position**

SUB, NWEC/SOS, and CRITFC/Yakama raised this issue in their rebuttal testimony or briefs, thereby denying BPA and other parties an adequate opportunity to develop a record on this matter. It is not clear how BPA's year-end cash position can be negative; cash is ordinarily a quantity that is either positive or zero. Therefore, the asserted biasing effect on the frequency of the FB CRAC from having a floor is tenuous.

BPA staff believe that the Treasury note is more readily available now than it was at the time of the 1993 rate case. Cross-examination, April 13, 2001, Tr. 173, Mr. Lovell. The facts that BPA's working capital needs are higher than \$50 million, and that the Treasury note is likely to be available during a genuine, temporary cash shortage but is not modeled in the ToolKit, balance each other, resulting in a reasonable modeling approach. The TPP has not been overstated.

### **Evaluation of Positions**

The size of the working capital assumption to be used in BPA's rate case modeling was a contentious issue in the 1993 rate case, at which time the \$50 million assumption was adopted. See section 5.4, 1993 Wholesale Power and Transmission Rate Proposal, Administrator's Record of Decision, July 1993. Any change to this figure would need to be preceded by adequate opportunity for all interested rate case parties to present testimony and rebuttal to others' testimony. This issue has been raised at a time too late in the 2002 rate case to allow the required debate.

Additionally, CRITFC/Yakama's argument that the \$50 million is insufficient and should be raised "or other short-term financing (be) in place" neglects the fact that BPA has access to a \$250 million short-term Treasury note, which could provide additional liquidity, if necessary. Cross-examination, April 13, 2001, Tr. 173, Mr. Lovell.

NWEC/SOS argue that BPA's 1993 ROD included arguments demonstrating that the short-term note was not readily available, contrary to current statements. If it is readily available, BPA is violating the power system emergency Criteria in declaring a power emergency to limit hydro operations for fish migration, and should be using the note to purchase more spill and to avoid, at least somewhat, the necessity of declaring a power system emergency. If the note is not available, BPA cannot rely upon it to justify refusing to model a higher cash flow need in its calculation of TPP. NWEC/SOS Ex. Brief, WP-02-R-2-NA/SA-02, at 6. BPA has indicated, however, that it believes it now will have access to the note for very short-term needs. Cross-examination, April 13, 2001, Tr. 177, Ms. Lefler. BPA has been working with Executive Agencies on tools to increase TPP. Burns and Berwager, WP-02-E-BPA-62, at 7; Cross-examination, April 13, 2001, Tr. 181, Ms. Lefler. The need for working capital on the order of \$300 million, rather than \$50 million, is due to the impact of net billing which retards but does not ultimately reduce BPA's receipt of cash. Rebuttal testimony of NWEC/SOS, WP-02-E-NA/SA-04, Attachment 1. This is clearly a short-term cash flow need for which the Treasury note is well-suited. Whether access to the note is assumed in the consideration of a power system emergency is outside the scope of this rate case.

### **Decision**

*BPA does not need to remove the "floor" in the ToolKit. It is reasonable for BPA to expect that the \$250 million Treasury note can be used to solve some very short-term cash-flow problems. BPA will continue to employ models in its rate case that use the assumption that BPA ends each year with a minimum of \$50 million in cash reserves. That assumption has not caused an overstatement of TPP values.*

#### **Issue 4**

*Whether BPA should model the SN CRAC.*

#### **Parties' Positions**

In its rebuttal testimony, SUB asserts that the use of a “floor” in the ToolKit, that is, assuming that each year except FY 2002 ends with at least \$50 million in reserves, leads to an underestimate of the rate impact of the SN CRAC on non-Slice customers. Nelson, WP-02-E-SP-03, at 11. When calculating this rate impact to non-Slice customers, BPA should include the impact of the SN CRAC. *Id.*

#### **BPA Staff Position**

Many of the details of how the SN CRAC would operate will have to be worked out in the separate 7(i) process started by a triggering of the SN CRAC, so modeling the SN CRAC is not feasible in this proceeding. Lefler, *et al.*, WP-02-E-BPA-67, at 5-12, lines 18-19.

#### **Evaluation of Positions**

There is no evidence in the record concerning the impact of modeling the SN CRAC, so there is no reason to believe that any party’s interest has been harmed by the lack of modeling of the SN CRAC. BPA has argued that modeling the SN CRAC is not realistically possible. Lefler, *et al.*, WP-02-E-BPA-67, at 5-12, lines 18-19.

#### **Decision**

*The SN CRAC need not be modeled.*

### **4.6            General Issues**

#### **Issue 1**

*Whether the analysis underlying the May Proposal was flawed and its proposed risk mitigation tools inadequate, and therefore BPA’s opinions and analyses should be viewed skeptically in this phase of the proceeding.*

#### **Parties' Positions**

NWEC/SOS asserts in their initial brief that the fact that there is need for a “Phase II” (*i.e.*, the Amended and Supplemental Proposals) in this case is evidence that BPA’s analysis in Phase I (*i.e.*, that part of this rate case that is described in the May ROD) was flawed and its proposed risk mitigation tools were inadequate, and therefore Bonneville’s opinions and analyses and those of JCG should be viewed skeptically in this phase of the proceeding. NWEC/SOS Brief, WP-02-B-NA/SA-02, at 2.

NWEC/SOS state that if the current power crisis had hit just a few months later, BPA's May Proposal would have been put into place, and the agency would now be confronting the prospect of "total bankruptcy" beginning in October, its limited CRAC mechanism completely unequal to the task; that this shows that the risk mitigation in BPA's May Proposal was faulty; and that this in turn is grounds for doubting BPA's analyses in this proposal. *Id.*

NRU agrees that BPA has employed a sound and reasonable approach to assessing and mitigating risk in this proposal. NRU Ex. Brief, WP-02-R-NI-02, at 4.

### **BPA Staff Position**

In May 2000, BPA released its May Proposal which met the multiple goals of keeping BPA competitive by providing customers with stable rates, adhering to an 88 percent probability standard for Treasury repayment, addressing potential problems of under- and over-collection of revenues through the CRAC and DDC mechanisms, and positioning itself to achieve a similarly high (80-88 percent) TPP for the FY 2007-2011 rate period. May ROD, WP-02-A-02, at 7-12. The Proposal was grounded in an analysis that, consistent with the views of market price uncertainty prevailing at that time, assumed much less price volatility than was actually seen in the fall of 2000. Lefler, *et al.*, WP-02-E-BPA-77, at 30.

As noted *supra* in the Introduction to this chapter, when BPA recognized the magnitude of the costs of meeting unanticipated augmentation load at unprecedented high market prices, it reassessed its risk profile and, in conjunction with the JCG, developed a more robust risk mitigation package in the Supplemental Proposal. This proposal contains a three-component CRAC and an automatic DDC mechanism that provide BPA with a great deal of flexibility in generating revenues while reducing the risk of rate volatility to its customers. *Id.*

### **Evaluation of Positions**

NWEC/SOS's assertion that the fact that there is a need for a Supplemental Rate Case indicates that the May Proposal was flawed begs a more fundamental question: "Does the simple fact that circumstances occurred that were considered unlikely (or completely unforeseen) in a risk analysis necessarily mean that the resulting mitigation package was flawed?" The answer to this question is "No."

Risk analysis is necessarily done on a probabilistic basis, where the likelihood of specific outcomes is derived from a combination of historical data and expert judgment. It is always possible that unforeseen changes such as those witnessed in the West Coast power market in late 2000 will render historical data and judgments based upon past trends and behavior obsolete as the basis for reliable risk distributions. (*See supra* section 4.1) However, even where no unforeseen changes occur, and probability distributions provide a good representation of the likelihood of different outcomes, there is always the possibility that an unlikely outcome will occur. Risk mitigation packages embody not only the results of a risk analysis but also a general approach to risk that determines whether or not the package provides adequate coverage. This approach defines an organization's risk tolerance; it weighs the cost of risk mitigation against the



acceptability of the risk remaining after mitigation measures have been taken. See May ROD, WP-02-A-02, at 7-13.

A proposal is not flawed simply because its risk mitigation mechanisms do not fully cover worst case outcomes. Parties in BPA's rate cases and FERC have long recognized that "less than 100 percent protection against risk is acceptable," *id.* at 7-13 and 7-14, and Principle No. 3 explicitly states that "a 100 percent probability of Treasury payment is not achievable." Supplemental Proposal Study Documentation, WP-02-E-BPA-69, at 5-4.

In addition, a proposal is not flawed simply because surprise outcomes could occur that could not be predicted or anticipated ahead of time, or because such an unanticipated, surprise outcome actually has occurred. As noted *supra*, no one in the utility industry was able to forecast the sudden onslaught of high prices in the California and West Coast power market, including, by their own admission, NWECS/SOS. NWECS/SOS Brief, WP-02-B-NA/SA-02, at 2.

The May Proposal included a set of risk mitigation tools that provided for an 88 percent TPP, with a small proportion of the games in the associated ToolKit analysis displaying very large deferrals. This was a level of risk deemed acceptable given the distributions of expected system augmentation and market prices employed at that time in the risk analysis. The base rates and mitigation tools associated with the May Proposal were well suited to an operating environment where BPA supplied most of its customers' loads with power from the FCRPS. However, they were not adequate to deal with meeting augmentation loads that could only be served by additional purchases made on the West Coast market. Accordingly, BPA initiated the Amended and Supplemental rate cases to deal with the problems of system augmentation, and designed more robust mitigation tools to deal with the revised risk profile. Lefler, *et al.*, WP-02-E-BPA-77, at 30.

Although BPA's May Proposal would not have been able to generate adequate revenues given prices and system augmentation requirements, neither its risk methodology nor its willingness to tolerate a certain level of risk as acceptable are indications that either the overall approach to risk or the proposal itself were flawed. BPA did not ignore significant risks in its analysis, nor did the design of its mitigation package leave it heavily exposed in a significant portion of modeled outcomes. It constructed a reasonable proposal given the spectrum of outcomes envisioned at that time, and has supplemented that proposal in a reasonable way to deal with the costs associated with additional load placement that could not be fully served by the resources assumed for the May Proposal.

### **Decision**

*BPA employed a sound and reasonable approach to assessing and mitigating risk, in both the May and Supplemental Proposals. Hence, this approach will not be changed.*

### **Issue 2**

*Whether BPA should reschedule interest and amortization from the early years of the rate period to the later years to decrease the likelihood of triggering the FB CRAC.*

## **Parties' Positions**

NRU proposes that BPA should use the flexibility available in repayment law and policy to reschedule payments to the U.S. Treasury out of FYs 2002 and 2003 and into the later years of the rate period. NRU Brief, WP-02-B-NI-03, at 4.

NRU recommends moving discretionary principal payments scheduled by the repayment studies for FYs 2002 and 2003, totaling \$68 million. *Id.* at 5. NRU states that in times of financial difficulty it is appropriate to shift these discretionary payments within the rate period to minimize rate impacts. *Id.* at 5-6. This would have the effect of reducing the likelihood that the FB CRAC would trigger because it would increase accumulated reserves by that amount. *Id.* at 6, lines 5-6.

NRU also urges BPA to delay payment of interest on appropriated funds during the rate period. They argue that this would not require Congressional action or changes in any law, but is authorized under Order RA 6120.2. *Id.* at 6. However, restructuring the timing of payments within the rate period should only be pursued under defined circumstances and with the support of the Northwest Congressional Delegation, given the current political circumstances BPA faces. *Id.* at 6, lines 14-18. NRU recommends that BPA plan to use this tool to mitigate the FB CRAC in the first two years of the rate period by seeking advance Treasury and Administration approval for such a restructuring under defined circumstances, *i.e.*, if the FB CRAC would otherwise trigger in the first two years of the rate period. *Id.* at 7. They go on to recommend that the total amount of rescheduled discretionary prepayments of principal and interest on appropriations be no greater than \$200 million in each of the first two years of the rate period, and that it should be clearly understood that this proposal does not envision a deferral of payments beyond the five-year rate period. *Id.*

NRU is in support of BPA continuing discussions with Treasury on such actions that would assist in making scheduled Treasury payments or provide Treasury's concurrence for modifications to planned payments. NRU Ex. Brief, WP-02-R-NI-02, at 4.

## **BPA Staff Position**

BPA has begun discussions with Treasury on the idea of prepayment credits, *i.e.*, when more principal is repaid in a given year than had been scheduled, a "credit" would be earned that can be applied in years when funds may be insufficient to make full scheduled amortization payments to Treasury. Burns and Berwager, WP-02-E-BPA-62, at 7, lines 3-6.

Repayment policy allows BPA to defer interest expense when funds are insufficient. The unpaid interest is capitalized, assigned a long-term interest rate, and must be repaid before any planned amortization. WP-02-FS-BPA-02, at 66-68.

## **Evaluation of Positions**

NRU's proposal is a "real-time" cash/debt management exercise rather than a planned rate filing provision. In the Supplemental Proposal, BPA intended to support, not change, the basic cost recovery demonstrations in the May filing. Supplemental Proposal Study, WP-02-E-BPA-67, at 1-3, line 25 to 1-4, line 2.

To receive Treasury concurrence to vary from existing policy would require more time than is feasible prior to the filing of this rate proposal. Any such changes should be dealt with at the time rather than as a modification to BPA's May Proposal. In the first years of the rate period, BPA could find itself in a position in which available Treasury credits such as interest income, 4(h)(10)(C), and FCCF may cover all or most of the scheduled payment. In that event, shifting amortization and interest would make no difference to the likelihood of the FB CRAC triggering.

### **Decision**

*BPA will not change planned payments to Treasury as part of the rate filing, but will continue discussions with Treasury on prepayment credits and other such actions that, at the time, would assist in making scheduled Treasury payments or provide Treasury's concurrence for modifications to the planned payments.*

### **Issue 3**

*Whether BPA's monthly cash flow management needs to be modeled for the Final Supplemental Proposal.*

### **Parties' Positions**

In their initial brief, NWECS/SOS argue that under current conditions, ensuring monthly cash flows becomes of increasing importance. Taking issue with BPA's assertion in rebuttal testimony that "solutions to cash flow problems must be found elsewhere than in rates" (*see* Lefler, *et al.*, WP-02-E-BPA-77, at 21), NWECS/SOS argue that businesses which follow sound business practices deal with cash flow problems all the time by having enough reserves in the bank to cover the ups and downs of cash-flow needs. NWECS/SOS Brief, WP-02-B-NA/SA-02, at 6.

NWECS/SOS disagree with BPA's position that BPA's cash management has not historically been considered to be a rate case issue. *Id.* at 6, footnote 1. They go on to argue that instead of dealing with cash flow problems elsewhere than in rates, Bonneville itself incorporates a cash-flow factor in calculating its own TPP to establish its rates. NWECS/SOS Brief, WP-02-B-NA/SA-02, at 6-7. In the 1993 rate case BPA established a minimum working capital level, which was determined after much discussion of BPA's *monthly* cash needs including alternative proposals by the Joint Customers. *Id.* BPA cannot be allowed to respond to this concern by declaring it not to be a rate case issue when it has for so long been one. *Id.*

NRU agrees that monthly cash management is not a rate case issue. NRU Ex. Brief, WP-02-R-NI-02, at 4.

### **BPA Staff Position**

BPA's cash management has not historically been considered to be a rate case issue except for the general test of sufficiency for Treasury payments, and BPA does not consider it to be one now. Lefler, *et al.*, WP-02-E-BPA-77, at 32. Also, higher rates cannot fix some of the most problematic aspects of cash flow, since the Net Billing agreements prevent BPA from receiving

cash from many of its public customers until the Energy Northwest budget has been paid. *Id.* This generally means that modifications of BPA rates for public customers would not affect BPA's cash flow in the first few months of a fiscal year. *Id.*

While the extremely high prices in the power market during FY 2001 and high price forecasts for FY 2002 have increased the importance of cash management during this time, virtually all current market forecasts point to a decline in market prices by FY 2003 or 2004 to levels only slightly higher than the levels seen before the surge that occurred in FY 2000. *Id.* It would not be prudent to construct a long-term cash management strategy on the basis of a short-term anomaly. *Id.* Additionally, introducing a major new financial standard would ordinarily be done with significant opportunities for the public to become involved, and this would not be possible if BPA proposed a new standard or accepted another party's suggestion of one in BPA's rebuttal testimony. *Id.* at 33.

### **Evaluation of Positions**

BPA's cash management has not historically been considered to be a rate case issue except for the general test of sufficiency for Treasury payments, and, as noted *supra* BPA does not consider it to be one now. Lefler, *et al.*, WP-02-E-BPA-77, at 32. The two citations NWEC/SOS uses in support of its contention, that monthly cash flow considerations are and have been rate case issues, are taken out of context. It is indeed true that "[i]n principle, sufficient reserves of cash can solve any cash flow problem." (*See supra*). If an agency or business had limitless funds available to it, it could solve literally any cash flow problem it might confront. In practice, it is not possible to guarantee sufficient reserves without the risk of bankrupting those from whom the funds are collected.

Secondly, as discussed *supra* in Section 4.5, Issue 5, while monthly cash flows were discussed in the 1993 rate case, they were discussed in the context of developing an annual amount to be used in the TPP model to describe end-of-year need. At no time have BPA's rate cases attempted to model month-to-month variations in cash in setting its rates.

### **Decision**

*It is not necessary to model monthly cash management.*

## **5.0 RATE CASE MARKET PRICE FORECAST FOR INVESTOR-OWNED UTILITIES' RESIDENTIAL EXCHANGE PROGRAM SETTLEMENTS**

### **5.1 Introduction**

In BPA's "Residential Exchange Program (REP) Settlement Agreements With Pacific Northwest Investor-Owned Utilities (IOUs), Administrator's Record of Decision (ROD), October 2000" (REP Settlement ROD), the Administrator decided to offer REP Settlement Agreements to regional IOUs. These Agreements were subsequently executed by BPA and the regional IOUs. BPA's REP Settlement Agreements with regional IOUs provide two types of benefits to the IOUs' residential and small farm consumers: (1) actual power sales at the Residential Load (RL) rate or Priority Firm Power (PF) Exchange Subscription rate; and (2) monetary benefits based on the difference between the RL (or PF Exchange Subscription) rate and BPA's rate case five-year flat block price forecast. The establishment of BPA's five-year flat block market forecast is therefore an issue in BPA's WP-02 rate case.

### **5.2 Rate Case Market Price Forecast for Investor-Owned Utilities' Residential Exchange Program Settlements**

#### **Issue**

*Whether BPA has established an appropriate price for its rate case market price forecast for the calculation of monetary benefits under the IOUs' REP Settlement Agreements.*

#### **Parties' Positions**

The IOUs (Avista Corporation, Idaho Power Company, PacifiCorp, Portland General Electric, and Puget Sound Energy, Inc.) argue that \$38/megawatthour (MWh) is an appropriate price to use as the rate case market price forecast for the calculation of monetary benefits under the IOUs' REP Settlements. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 2-5.

Springfield Utility Board (SUB) argues that BPA proposes to increase the IOUs' financial REP Settlement Agreement benefits by using a \$38/MWh forecast instead of the \$28.10/MWh forecast used in BPA's May 2000 Final Power Rate Proposal (May Proposal), *citing* Doubleday, *et al.*, WP-02-E-BPA-74, at 6-7. SUB Brief, WP-02-B-SP-02; SUB Ex. Brief, WP-02-R-SP-02, at 5-7. SUB argues that this change is inconsistent with BPA's prior May ROD. *Id.*

#### **BPA Staff Position**

BPA staff state that \$38/MWh is an appropriate price to use as the rate case market price forecast for the calculation of monetary benefits under the IOUs' REP Settlements. Doubleday, *et al.*, WP-02-E-BPA-78, at 9.

## Evaluation of Positions

To thoroughly understand this issue, it is helpful to review the record that documents the development of the rate case market price forecast that is used in the calculation of monetary benefits under the IOUs' REP Settlements. These REP settlements are described in greater detail in BPA's "Power Subscription Strategy" and in the REP Settlement ROD.

For the purposes of the WP-02 rate case, BPA 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; (4) estimating the cost of augmenting the Federal Base System (FBS) with five-year flat-block purchases; and (5) developing BPA's Cost Recovery Adjustment Clause (CRAC) analyses. Doubleday, *et al.*, WP-02-E-BPA-65. BPA's initial five-year flat block price forecast was used for two purposes. *Id.* The first purpose was 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. *See* Oliver, *et al.*, WP-02-E-BPA-20, at 3-4. 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. . . .

BPA staff stated that it was necessary to develop a separate forecast for this purpose. *See* Oliver, *et al.*, WP-02-E-BPA-20. The second purpose of BPA's initial forecast was 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 flat block purchases. *See* Oliver, *et al.*, WP-02-E-BPA-20, at 3. 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 Marginal Cost Analysis (MCA), market quotes for forward transactions in the five-year period, and a reasonable extrapolation of current market prices. *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 determined that a price of \$28.10/MWh reasonably reflected the average long-term purchase price for five-year flat block energy. *Id.* at 7.

In BPA's 2002 Amended Power Rate Proposal (Amended Proposal), BPA staff again noted that BPA's REP Settlement Agreements provide two types of benefits to the residential and small farm consumers of regional IOUs: (1) actual power sales at the RL rate or PF Exchange Subscription rate; and (2) monetary benefits based on the difference between the RL (or PF Exchange Subscription) rate and BPA's rate case five-year flat block price forecast. Doubleday, *et al.*, WP-02-E-BPA-65, at 4. BPA proposed that its RL and PF Exchange Subscription rates for power sales to IOUs should be subject to CRACs. *Id.* BPA's proposed CRACs would affect the effective level of the RL and PF Exchange Subscription rates and, therefore, the cost of the power sale portion of the REP Settlements. *Id.* In addition, the monetary portion of the REP Settlement benefits would be calculated using the difference between the RL (or PF Exchange Subscription) rate and BPA's Amended Proposal for a five-year flat block price forecast, which differed from the five-year flat block price forecast used in BPA's May Proposal. *Id.* In BPA's Amended Proposal, BPA staff proposed to use the risk-adjusted average market price forecast for the Fiscal Year (FY) 2002-2006 rate period that was developed in BPA's May Proposal. *Id.* The risk-adjusted average market price forecast is the average spot market price for all hours of the year estimated by AURORA to quantify BPA's operating risk in Risk Analysis Model (RiskMod) for the Risk Analysis Study. *Id.* The risk-adjusted average market price forecast in BPA's May Proposal was \$34.1/MWh. *Id.*, citing Conger, *et al.*, WP-02-E-BPA-63.

BPA staff proposed this change in the Amended Proposal for some of the same reasons it proposed to amend the May Proposal. Doubleday, *et al.*, WP-02-E-BPA-65, at 5. First, BPA's load obligations had increased substantially over earlier rate case forecasts on which BPA's May Proposal market price forecast, in part, was based. *Id.* The increase in load obligations would make it difficult for BPA to meet all its augmentation needs with five-year flat block purchases made prior to the start of the rate period. *Id.* Since a substantial portion of BPA's purchase requirements may be met with spot market or short-term forward purchases, it was more reasonable to use BPA's rate case risk-adjusted average price forecast as the five-year forward flat block forecast of market prices for calculating monetary settlement benefits. *Id.* In addition, there was a realistic expectation that market prices could be higher than anticipated in the May Proposal. *Id.* Therefore, changing from the prior market price forecast of \$28.10/MWh to BPA's proposed \$34.1/MWh rate case market forecast was a reasonable step to meet the original intent of the Power Subscription Strategy. *Id.* The \$34.1/MWh rate also would have more accurately reflected BPA's purchase power costs for its entire amount of five-year flat blocks of power for the rate period. *Id.*

The five-year flat block forecast was designed: (1) to capture the costs of making purchases prior to the rate period for terms longer than one year to augment the FBS; and (2) to estimate the cost of advance purchases of five-year flat block energy by the IOUs. *Id.*, citing Oliver, *et al.*, WP-02-E-BPA-20, at 3. BPA anticipated that actual purchases of power would be made above and below the forecast price and that a portion of the energy would be provided from surplus energy and not energy purchased in advance of the rate period. Doubleday, *et al.*, WP-02-E-BPA-65, at 5; Doubleday, *et al.*, WP-02-E-BPA-65(E2).

At the time of the Amended Proposal, BPA staff felt that the risk-adjusted average market price forecast of \$34.1/MWh was reasonable for three reasons. *Id.* at 6. First, while then-current forecasts of the average price of the marginal MWh for the five-year rate period, purchased during the five-year rate period, might average in the \$40 to \$50/MWh range, BPA had already purchased over 700 average megawatts (aMW) of power at prices at or below \$28.10/MWh. *Id.* The then-current estimate of the amount of power BPA would purchase during the five-year rate period was 3,305 aMW (1,745 aMW of BPA purchases for forecasted loads plus 1,560 aMW of additional purchases for non-forecasted loads). *Id.* BPA expected to purchase the 3,305 aMW per year at an average cost that is below the marginal cost indicated by the then-current market price forecasts used in establishing BPA's new proposed CRACs. *Id.* Second, the monetary benefits are provided for 900 aMW of IOU RL service under the REP Settlements. *Id.* BPA staff stated that the IOUs must make purchases to serve these 900 aMW of RL service during the five-year rate period. *Id.* BPA staff argued that the IOUs had known about the need to purchase additional resources to serve these loads since December 1998 and had likely made some or all of those purchases. *Id.* BPA staff argued that since the five-year forward flat block forecast was designed to forecast the market price of these forward purchases, it was reasonable to conclude that some or all of the IOU purchases were made prior to the recent increase in market prices. *Id.*

Third, current estimates of the market price would not be an appropriate forecast to use for purchases that cover a range of market conditions and purchases. *Id.* As discussed in the policy testimony of Burns and Berwager, WP-02-E-BPA-62, BPA had addressed the impact of the current price volatility for the REP Settlements by proposing to exempt the RL and PF Exchange Subscription rates from the application of the proposed CRACs when such rates were used for calculating monetary benefits. *Id.* at 6-7. BPA staff noted that it was more appropriate to eliminate the cost impacts of current price volatility from the rates used to calculate the monetary benefits rather than redoing a forecast at the end of the forecast period, citing Burns and Berwager, WP-02-E-BPA-62. *Id.* at 7. BPA's Amended Proposal proposed the use of a forecast made during its rate case as BPA's five-year forward flat block forecast. *Id.*

In its 2002 Supplemental Power Rate Proposal (Supplemental Proposal) direct testimony, BPA staff built upon their Amended Proposal. BPA staff noted that BPA had made a policy decision to adjust its forward flat block forecast from \$34.1/MWh to \$38/MWh. Doubleday, *et al.*, WP-02-E-BPA-74. This issue is addressed in the policy testimony of Burns and Berwager, WP-02-E-BPA-70. This adjustment was made for a number of reasons. Doubleday, *et al.*, WP-02-E-BPA-74. In summary, BPA staff recently conducted settlement discussions with all interested parties in BPA's WP-02 rate case. *Id.*, citing Burns and Berwager, WP-02-E-BPA-70. A large number of those parties proposed a partial settlement of many rate case issues. *Id.* One element of that proposal was that the forecast used to calculate the financial benefits under the REP Settlements should be \$38/MWh. *Id.* When viewed in the context of the Partial Stipulation and Settlement Agreement, BPA staff elected to make this adjustment, also noting that prices had increased since the time of BPA's Amended Proposal. *Id.* While BPA staff did not expect current prices to continue for the five-year period of the forward flat block forecast, BPA staff believed, viewed in the context of the total settlement proposal, that current high market prices lasting through the first 6 to 18 months of the forecast period justified an increase in the forecast price to \$38/MWh. *Id.*



In addition to the issue of the rate case market price forecast, there is another issue that affects prospective REP Settlement benefits. As originally proposed in BPA's Amended Proposal in the policy testimony of Burns and Berwager, WP-02-E-BPA-62, BPA staff proposed that the RL and PF Exchange Subscription rates, only when used for the calculation of monetary benefits for the 900 aMW designated as monetary benefits in the REP Settlements, should be exempt from the proposed Load-Based (LB) and Financial-Based (FB) CRACs. *Id.* BPA staff argued that REP Settlement Power (1,000 aMW) that is converted into monetary benefits under the REP Settlement, however, should be subject to the LB CRAC and FB CRAC, in the calculation of such new monetary benefits. *Id.* The LB CRAC is designed to recover the cost of serving load not forecasted in the May Proposal. *Id.* The FB CRAC is designed to recover higher than expected costs, including increased market price purchases of power. *Id.* BPA chose to protect the 900 aMW designated as monetary benefits from current price volatility by exempting the RL and PF Exchange Subscription rates from the proposed LB and FB CRACs instead of changing the forecast of five-year forward flat block purchases. *Id.* Since the amount of the monetary portion is fixed, it was reasonable to exclude the load served by the monetary benefits from the possible rate volatility introduced by application of the proposed LB and FB CRACs. *Id.* BPA staff's proposal provides a greater amount of certainty to the monetary benefit calculation. *Id.*

The foregoing summarizes BPA staff's positions in this proceeding. The IOUs agreed with BPA staff on certain issues, but disagreed with BPA staff on other issues, as noted below. In their initial brief, the IOUs note that within months of issuing the May ROD, BPA recognized that unpredicted events had resulted in an extremely volatile market with prices far higher (particularly in the first two years) than its five-year flat block forecast and increased demand. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 2. This recognition led to the reopening of this proceeding in order to redesign BPA's risk mitigation tools to handle unforeseen costs and make other appropriate adjustments to its rate proposal. *Id.* The IOUs also note that because of the extreme volatility of the current wholesale electricity market, BPA identified and revised its estimated five-year flat prices several times during this phase of the proceeding. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 2-3, citing Conger, *et al.*, WP-02-E-BPA-63, at 14; BPA's Supplemental Proposal Study Documentation, WP-02-E-BPA-69, at 5-18; Lefler, *et al.*, WP-02-E-BPA-73, at 38; and Doubleday, *et al.*, WP-02-E-BPA-74, at 7. The IOUs note that this extreme volatility led the Joint Customers Group (JCG) to propose cost-recovery adjustments every six-months with twice yearly true-ups to the actual cost of purchasing augmentation power. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 3. This proposal was incorporated into the Partial Stipulation and Settlement Agreement. *Id.*, citing Burns and Berwager, WP-02-E-BPA-70, at 4-14.

The IOUs argue that whether the \$38/MWh price used to calculate the financial portion of benefits for the IOUs' residential customers constitutes a reasonable five-year flat block forecast as contemplated by the Subscription Strategy is not a rate case issue subject to Federal Energy Regulatory Commission (FERC) review. *Id.* at 4. The IOUs argue that the decision BPA must make is whether using the stipulated \$38/MWh price is arbitrary or capricious based on the rate case record. *Id.* It is not arbitrary or capricious to select \$38/MWh where the vast majority of BPA's customers, the four state commissions, and BPA staff have agreed (only as part of a broader settlement) that it is an acceptable proxy for a five-year flat block forecast. *Id.*, citing Brattebo, *et al.*, WP-02-E-JCG-02, at 16-18.

The IOUs argue that BPA and the IOUs recognize that the 28.10 mill forecast is not an accurate five-year flat block forecast for 900 aMW of power to be delivered commencing October 1, 2001, citing BPA's Supplemental Study, WP-02-BPA-69, at 5-18, and Brattebo, *et al.*, WP-02-E-JCG-02, at 21. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 3. The IOUs note that BPA staff, mindful of the Administrator's commitment to deliver the financial equivalent of 900 aMW of power to the IOUs' residential customers, yet desirous of lowering BPA's costs in the face of a massive rate increase, argued that the five-year flat block forecast need not be adjusted to reflect today's prices in order to provide the companies with the financial equivalent of 900 aMW. *Id.* Rather, according to BPA staff, the Administrator should exempt these financial benefits from the LB and FB CRACs and assume that the IOUs purchased some portion of the 900 aMW between December 1998 (when BPA began purchasing some portion of its anticipated augmentation needs) and December 2000 (when BPA filed its Amended Proposal). *Id.* The IOUs agree that exempting their residential customers' financial benefits from the LB and FB CRACs is necessary because the Partial Stipulation and Settlement Agreement, in the IOUs' view, will not provide these customers with the financial equivalent of 900 aMW at the proposed \$38/MWh price, citing Brattebo, *et al.*, WP-02-E-JCG-02, at 11. *Id.* The IOUs argue, however, that the Administrator need not, and should not, assume that the IOUs had purchased some portion of the 900 aMW of power before the end of 2000 in order to justify the reasonableness of the \$38/MWh price for the purpose of calculating the financial benefits for the IOUs' residential customers. *Id.* The IOUs argue that, as the JCG explained, BPA staff's assumption is wrong, citing Brattebo, *et al.*, WP-02-E-JCG-02, at 16-17. *Id.* at 3. Also, the IOUs argue that it is unnecessary for the Administrator to make such a finding. IOU Brief, WP-02-B-AC/GE/IP/PL/PS-02, at 4.

BPA agrees with the IOUs that BPA must determine whether using the stipulated \$38/MWh price is arbitrary or capricious based on the rate case record. BPA agrees that it is not arbitrary or capricious to select \$38/MWh where the vast majority of BPA's customers, the four state commissions, and BPA staff have agreed (only as part of a broader settlement) that it is an acceptable proxy for a five-year flat block forecast. After review of the record, BPA agrees with the IOUs in finding that it is unnecessary to assume that the IOUs had purchased some portion of the 900 aMW of power before the end of 2000 in order to justify the reasonableness of the \$38/MWh price for the purpose of calculating the financial benefits for the IOUs' residential customers. The record shows that the members of the JCG and BPA staff support the adoption of \$38/MWh as the price forecast to be used in calculating financial benefits under the REP settlements. *See* Doubleday, *et al.*, WP-02-E-BPA-74. The record shows that BPA staff also agree with the JCG that there is currently a broad range of market forecasts in a volatile and changing market and that \$38/MWh, which is reflected in the Partial Stipulation and Settlement Agreement, represents a reasonable forecast to be used in the determination of financial benefits under the REP settlements. Doubleday, *et al.*, WP-02-E-BPA-78, at 9. While the record shows support for the \$38/MWh forecast in a volatile and changing market, the record lacks any evidence demonstrating that the \$38/MWh forecast is inappropriate for any substantive reason. While some parties do not appear to like the result of the adoption of a \$38/MWh forecast, which increases the amount of monetary benefits provided to IOUs under the REP Settlement Agreements, this does not show any substantive deficiency in the forecast itself. Doubleday, *et al.*, WP-02-E-BPA-78, at 4-5. The forecast is simply an element that is developed in BPA's rate case and inserted into current REP Settlement Agreements, which were previously

established in separate public processes. As discussed in greater detail below, BPA does not determine the reasonableness of the REP Settlement Agreements in the rate case. *Id.* at 4-8.

SUB argues that BPA proposes to increase the IOUs' financial REP Settlement Agreement benefits by using a \$38/MWh forecast instead of the \$28.10/MWh forecast used in BPA's May Proposal, citing Doubleday, *et al.*, WP-02-E-BPA-74, at 6-7. SUB Brief, WP-02-B-SP-02. SUB argues that this change is inconsistent with BPA's prior May ROD. *Id.* While BPA's forecast is different from that in BPA's May Proposal, BPA is not precluded from revising the rate case market price forecast used to calculate monetary benefits under the IOUs' REP Settlement Agreements. It should be recalled that the purpose of the forecast is for the calculation of monetary settlement benefits, that is, the forecast is part of a formula to determine the proper amount of benefits that should be provided to the IOUs for a settlement of their participation in the REP. This is a discrete purpose that was originally envisioned in BPA's Power Subscription Strategy and for which BPA must develop an appropriate rate case market price forecast. BPA's revision to the forecast is being conducted in accordance with section 7(i) of the Northwest Power Act, also as provided in BPA's Power Subscription Strategy. 16 U.S.C. § 839e(i). BPA staff previously explained why the \$28.10/MWh forecast was changed. *See, e.g.*, Burns and Berwager, WP-02-E-BPA-62, at 14; Doubleday, *et al.*, WP-02-E-BPA-65; Burns and Berwager, WP-02-E-BPA-70, at 11; Doubleday, *et al.*, WP-02-E-BPA-78, at 9. BPA therefore properly changed its rate case market price forecast to \$38/MWh from BPA's May Proposal.

In its brief on exceptions, SUB states that in one section of the 2002 Draft Supplemental Record of Decision (Draft Supplemental ROD), BPA bases its arguments regarding the Industrial Firm Power Targeted Adjustment Charge (IPTAC) rate on a limited scope of issues in this proceeding, while in another section of the WP-02 Draft Supplemental ROD, BPA states that it is not precluded from modifying the market price forecast for IOU benefits. SUB Ex. Brief, WP-02-R-SP-02, at 5. SUB argues that this alleged inconsistency should be corrected and the price used to determine IOU financial benefits should not be increased. *Id.* First, it must be noted that while BPA's own proposal may be limited to certain issues, BPA did not limit the scope of issues that could be raised by other parties in this proceeding any differently than BPA did in its May Proposal. BPA's testimony expressly notes that:

BPA's Amended Proposal does not require that every issue that was debated and decided in the May Proposal be reexamined. Many of those issues are not germane to the cost recovery problem that this amended proceeding has been initiated to address. By the same token, BPA recognizes that the parties may have different views on the issues that are germane or may wish to sponsor their own solution. Accordingly, the scope of this proceeding is limited only to the scope of the first phase of this rate case. *See* 64 Fed. Reg. 44318 (August 13, 1999) and the 2002 Final Power Rate Proposal Administrator's Record of Decision, WP-02-A-02 (May ROD).

Burns and Berwager, WP-02-E-BPA-62, at 3-4. Thus, the scope of this rate proceeding clearly encompasses the rate case market price forecast for the calculation of the IOUs' monetary benefits under the REP Settlement Agreements. The forecast also was expressly raised as an issue at the outset of BPA's Amended and Supplemental Proposals. *See* Doubleday, *et al.*,

WP-02-E-BPA-65; Doubleday, *et al.*, WP-02-E-BPA-74. As noted above, BPA staff previously explained why the \$28.10/MWh forecast in BPA's May Proposal was changed and why BPA's proposed \$38/MWh forecast is appropriate.

In addition, BPA staff did not base their arguments regarding the IPTAC rate on a "limitation of the scope of changes in this proceeding to CRAC redesign and Slice product adjustments." Instead, BPA staff reviewed the issue of proposed changes to the IPTAC rate and concluded, in their opinion, that such changes were inappropriate and that BPA could best address its risk problems through rate mitigation measures and without having to completely develop new rates. BPA did not reject the parties' IPTAC arguments on the basis that they were outside the scope of the rate case.

### **Decision**

*BPA has established an appropriate price for its rate case market price forecast for the calculation of monetary benefits under the IOUs' REP Settlement Agreements.*

## **5.3 Residential Exchange Program Settlement Agreements with Regional Investor-Owned Utilities**

### **Issue**

*Whether the benefits provided under the REP settlements with regional IOUs are reasonable.*

### **Parties' Positions**

The JCG argues that certain parties' allegations that the REP settlement benefits are unreasonable are based on faulty premises and are beyond the scope of the WP-02 rate proceeding. JCG Brief, WP-02-B-JCG-02, at 17-19.

### **BPA Staff Position**

BPA staff note that BPA's wholesale power rate cases do not establish settlement agreements or determine the reasonableness of BPA's settlements. Doubleday, *et al.*, WP-02-E-BPA-78, at 4.

### **Evaluation of Positions**

The JCG notes that, during the hearing, certain parties argued that the benefits obtained by the IOUs under the REP settlements are, due to changed circumstances, far greater than was intended at the time the settlement was entered into, and that the level of benefits is now unreasonable, citing Schoenbeck and Bliven, WP-02-E-DS-06, at 8-10. JCG Brief, WP-02-B-JCG-02, at 17. The JCG notes that these parties urge BPA to alter the terms of REP settlements, and to reduce the level of benefits being provided. *Id.* The JCG argues that these arguments are based on faulty premises, and should be rejected by the Administrator. *Id.* The predicate for these arguments is a faulty comparison between the benefits that the IOUs might have received under the REP and those being provided under the REP settlements. *Id.* In making this comparison, these parties fail to take into account two salient factors. *Id.*

First, these parties materially underestimate the level of benefits that might have been available to the IOUs under the REP. *Id.* They fail to consider the financial impact of the IOUs being potentially allowed to include such items as income taxes in average system cost (ASC), and the effect of market power purchases on ASC, in their benefit calculations. *Id.*, citing Brattebo, *et al.*, WP-02-E-JCG-03, at 20-23. BPA staff also noted that there are many variables that could substantially increase the value of the traditional REP. Doubleday, *et al.*, WP-02-E-BPA-78, at 2-3. This issue is discussed at great length in BPA's REP Settlement ROD. *Id.*

Second, the parties' arguments fail to recognize that while the escalating price of power on the wholesale market increases the value of the power available to the IOUs under the REP settlements, it also effectively decreases the value of the financial portion of the REP settlements at the same time. JCG Brief, WP-02-B-JCG-02, at 17-18. And since the power deliveries (1,000 aMW) and the financial benefits (900 aMW) are essentially of equal magnitude, the increasing value of the power deliveries is essentially negated by the decreasing value of the financial benefits. *Id.* at 18. These arguments also overlook the benefit of certainty that BPA achieved by entering into the REP settlements. *Id.*

The JCG correctly notes that the remedy sought by these parties, revision of the benefits available under the REP settlements, is beyond the scope of this WP-02 proceeding. JCG Brief, WP-02-B-JCG-02, at 18. BPA's wholesale power rate cases do not establish settlement agreements or determine the reasonableness of BPA's settlements. Doubleday, *et al.*, WP-02-E-BPA-78, at 4. BPA conducted a separate public involvement process regarding the development and offer of the REP settlements. *Id.*, citing the REP Settlement ROD. The DSIs were among the parties commenting on the proposed settlements in that forum. *Id.* After issuance of the REP Settlement ROD, the REP settlements were executed by BPA and the IOUs in October 2000. *Id.* BPA will not determine the reasonableness of the REP settlements in this forum.

Finally, the JCG correctly notes that issues regarding BPA's Power Subscription Strategy were excluded from the scope of this proceeding in the Federal Register Notice that initiated the WP-02 proceeding. JCG Brief, WP-02-B-JCG-02, at 18, citing 64 Fed. Reg. 44,318-44,323 (1999). These exclusions were reiterated in the Federal Register Notice that commenced the amended phase of the WP-02 rate proceeding. *Id.* This notice stated in part:

The second area of exclusion concerns decisions made in the Subscription Strategy. 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 ...

*Id.*, citing 65 Fed. Reg 75,275 (2000).

### **Decision**

*Parties' allegations regarding the appropriateness of benefits provided under the REP settlements are misplaced. BPA's wholesale power rate cases do not establish settlement agreements or determine the reasonableness of BPA's settlements.*

## 6.0 RATE DIRECTIVES

### 6.1 Introduction

Section 7 of the Northwest Power Planning and Conservation Act (Northwest Power Act) contains directives for the development of BPA's wholesale power rates. 16 U.S.C. § 839e. Among these directives is section 7(b)(2). 16 U.S.C. § 839e(b)(2). 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 ("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.

Other rate directives include those governing the development of rates for the DSIs, which are found in section 7(c) of the 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). 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. 16 U.S.C. § 839e(c)(2). Section 7(c)(2) also establishes the so-called DSI "floor rate," which requires that the DSIs' rates shall be no less than the rates in effect for the contract year ending June 30, 1985. *Id.*

### 6.2 Rate Directives

#### Issue

*Whether BPA's proposed wholesale power rates comply with the Northwest Power Act's rate directives.*

#### Parties' Positions

The DSIs argue that BPA's 2002 Final Power Rate Proposal (May Proposal) under-forecasted section 7(b) loads and the costs of purchased power. DSI Brief, WP-02-B-DS/AL-02, at 36-37; DSI Ex. Brief, WP-02-R-DS/AL-02, at 2-4. The DSIs argue that incorporating corrections to these items will result in a large rate increase. *Id.* The DSIs argue that BPA has failed to determine if the rates resulting from its current Supplemental Proposal meet the statutorily-required rate directives. *Id.* The DSIs and Springfield Utility Board (SUB) argue that BPA should rerun BPA's section 7(b)(2) rate test. *Id.*; SUB Brief, WP-02-B-SP-02, at 7; SUB Ex. Brief, WP-02-R-SP-02, at 5-7.

## **BPA Staff Position**

BPA staff state that the administrative record demonstrates that BPA's proposed rates are consistent with the Northwest Power Act's ratemaking directives. Ebberts, *et al.*, WP-02-E-BPA-79.

## **Evaluation of Positions**

The DSIs argue that BPA's development of rates must comply with the rate directives of the Northwest Power Act, and in particular sections 7(b) and section 7(c) of the Act. 16 U.S.C. § 839e(b); 16 U.S.C. § 839e(c). *See* DSI Brief, WP-02-B-DS/AL-02, at 36-37. After citing section 7(b) of the Northwest Power Act, the DSIs argue that this provision requires BPA to identify the amount of sales to the loads specified in section 7(b) and the cost of resources used to serve such loads. *Id.* at 37. The DSIs note that in the May Proposal, BPA forecasted that it would sell 5,783 average megawatts (aMW) of energy to section 7(b) loads on average over the five-year rate period, citing the Documentation to the Wholesale Power Rate Development Study, WP-02-FS-BPA-05A, at 36. *Id.* The DSIs note that BPA subsequently determined that it would serve an additional 1,472 aMW of public agency load that BPA had not included in the May Proposal, citing the 2002 Amended Power Rate Proposal Study, WP-02-E-BPA-58, at 2-5. *Id.* The DSIs state that BPA also concluded that the cost of meeting this additional load and a 46 aMW increase in DSI load would far exceed the costs reflected in the base rates adopted in the May Proposal. *Id.* The DSIs note that BPA concluded that the costs of purchased power included in the rates developed in BPA's May Proposal were too low, citing "BPA's Proposed Amendments to 2002 Wholesale Power Rate Adjustment Proposal, 65 Fed. Reg. at 75,274." *Id.* The DSIs note, Tr. 38, that BPA expects the total rate increase needed to cover these costs it failed to anticipate in the May Proposal to be in the range of 50 percent to 300 percent. *Id.*

The DSIs argue that these are large changes that dwarf the 1.7 percent increase in the Priority Firm (PF) rate adopted in May, including the 1 percent additional increase represented by the expected value of the Cost Recovery Adjustment Clause (CRAC) adopted in May. DSI Brief, WP-02-B-DS/AL-02, at 37. The DSIs allege that the lower range of the expected increase, 50 percent, is 10 times the largest rate increase BPA's head of rates can ever recall BPA adopting. *See* Tr. 139-140; *Id.* The DSIs argue that BPA simply failed to determine if the rates resulting from its current Supplemental Proposal meet the statutorily-required rate directives. *Id.* at 37-38. The DSIs make similar arguments in their brief on exceptions. DSI Ex. Brief, WP-02-R-DS/AL-02, at 2-4.

First, BPA acknowledges that BPA's customers may pay significantly higher prices under BPA's final WP-02 rate proposal than under BPA's May Proposal. However, the DSIs' implication that a 50 percent increase would be BPA's largest rate increase is mistaken. For example, BPA's previous rate decisions show that in 1979, BPA implemented a wholesale power rate increase of 107 percent. Similarly, a 61 percent wholesale power rate increase occurred in 1981. Also, a 54 percent rate increase occurred in 1982. BPA does not know the exact level of BPA's proposed rates because BPA has not yet implemented the CRAC provisions, which are risk mitigation measures added to BPA's base rates. In addition, BPA is taking actions outside of the

rate case that might reduce the ultimate level of any proposed rate increase. Burns and Berwager, WP-02-E-BPA-75, at 15.

The DSIs' central argument is that BPA has failed to determine if the rates that result from applying risk mitigation measures to BPA's base rates, as provided in BPA's Supplemental Proposal, meet the statutorily-required rate directives. This argument is not well-founded. BPA's base rates developed in its May Proposal are not changing and are not higher than they were when proposed in May. As discussed in greater detail below, the studies conducted in the development of BPA's base rates are therefore still applicable. Also, BPA's Supplemental Proposal is comprised of risk mitigation measures to be applied to BPA's base rates. This provides BPA flexibility to respond to volatile market conditions during the rate period, which could not be accomplished through fixed rates. BPA therefore did not develop new wholesale power rate schedules in its Supplemental Proposal for which new studies were required.

While BPA agrees that BPA's rates must comply with the Northwest Power Act's rate directives, the DSIs ignore the existing record of this proceeding. Ebberts, *et al.*, WP-02-E-BPA-79, at 4-5. In the initial phase of this proceeding, BPA's May Proposal clearly implemented all of BPA's rate directives, including the three rate directives noted by the DSIs: the section 7(b)(2) rate test, the section 7(c)(2) floor rate test, and the section 7(c)(2) Industrial Firm Power (IP)-PF link. Some of the record evidence documenting the section 7(b)(2) rate test includes BPA's direct and rebuttal testimony. *See* Kaptur, *et al.*, WP-02-E-BPA-34; Kaptur, *et al.*, WP-02-E-BPA-56. Additional evidence includes BPA's 2002 Section 7(b)(2) Rate Test Study, WP-02-FS-BPA-06, and Documentation, WP-02-FS-BPA-06A, and the Wholesale Power Rate Development Study, WP-02-FS-BPA-05. *Id.* Some of the record evidence documenting the section 7(c)(2) floor rate and the IP-PF link similarly includes BPA's direct and rebuttal testimony. *See* Ebberts, WP-02-E-BPA-22; Ebberts, WP-02-E-BPA-47. Additional evidence includes BPA's 2002 Wholesale Power Rate Development Study, WP-02-FS-BPA-05, at 65-66, and 61-63, respectively. In addition to the foregoing evidence, the record also contains evidence on these issues such as the parties' direct and rebuttal testimonies, parties' initial briefs, parties' briefs on exceptions, etc. The record shows that there is no question that BPA has implemented the Northwest Power Act's rate directives in the WP-02 rate proceeding.

Furthermore, BPA's Amended and Supplemental Proposals must be viewed in conjunction with the foundation of BPA's May Proposal. Ebberts, *et al.*, WP-02-E-BPA-79, at 4-5. The latter stages of BPA's rate proceeding have dealt specifically with addressing unprecedented market conditions, characterized by enormous volatility and extremely high prices. *Id.* From a ratemaking perspective, it is prudent to deal with these problems through flexible risk mitigation tools, rather than subjecting consumers to cost allocations and rate increases that are predicated, in large part, on future events that are extremely volatile. *Id.* This is addressed in greater detail below.

It is helpful to recount BPA's policy testimony in the Amended and Supplemental Proposals, which explains how BPA identified a risk mitigation problem in BPA's May Proposal that could best be addressed through the revision of BPA's risk mitigation tools. *See* Burns and Berwager, WP-02-E-BPA-62; Burns and Berwager, WP-02-E-BPA-70. In July 2000, BPA filed proposed rate adjustments for its wholesale power rates (May Proposal) with the Federal Energy



Regulatory Commission (FERC). Burns and Berwager, WP-02-E-BPA-62, at 2-6. Subsequent to that time, however, during the late spring and summer months, the West Coast power markets suffered price increases and volatility that had not been seen before. *Id.* By August, it was clear that these market prices were not a short-term phenomenon. *Id.* This meant that BPA's cost-based rates, which were already below the original market forecast, were even more attractive. *Id.* Thus, BPA assumed that additional load would be placed on BPA, and BPA would need to purchase additional power to augment the Federal Columbia River Power System (FCRPS) supply. *Id.* BPA determined that the implications for cost recovery were so serious that a stay of the rate proceeding at FERC was requested. *Id.* This enabled BPA to review the events that had occurred during the summer months and to determine whether the escalating prices and increased volatility would require remedial action. *Id.*

Escalating and more volatile market prices had two related effects. *Id.* First, the specter of higher prices and continued unpredictability caused customers to place as much load as possible on BPA. *Id.* Second, to meet this increased load obligation, BPA would need to make substantially greater power purchases at substantially higher and more uncertain prices than anticipated in the May Proposal. *Id.* BPA concluded that the May Proposal, as filed with FERC, was not adequate to deal with the added costs and financial risks that the high and volatile market prices created for BPA. *Id.*

During the initial phase of the rate case, BPA's load forecast exceeded BPA's forecast of generation resources, requiring BPA to purchase up to 1,745 aMW of system augmentation. *Id.* BPA then expected that loads would exceed the original rate case forecast by an additional 1,518 aMW, requiring BPA to purchase up to an additional 1,560 aMW of system augmentation. *Id.*; see Conger, *et al.*, WP-02-E-BPA-63. Inasmuch as the generating capability of the FCRPS was already inadequate to meet the earlier load forecast, BPA would be required to purchase to further augment its inventory to serve these additional loads. Burns and Berwager, WP-02-E-BPA-62, at 2-6. The cost of power to serve these unanticipated loads was not included in revenue requirements. *Id.*

The combination of an unanticipated increase in loads and purchase requirements, with higher and more uncertain market prices, greatly diminished the probability that rates proposed in the May Proposal will fully recover generation function costs. *Id.* Absent a change to the May Proposal, Treasury Payment Probability (TPP) would be reduced to below 70 percent, a level which falls well short of specific goals and targets. *Id.* In BPA's judgment, BPA had a serious cost recovery problem that it was obliged to address by reason of statute and Administration policy. *Id.*

BPA's Amended and Supplemental Proposals were a continuation of the WP-02 Rate Proceeding. *Id.* They were limited in purpose but not in scope of issues. *Id.* The Amended and Supplemental Proposals were being conducted for the discrete purpose of resolving a cost recovery problem brought about by market price trends and load placement changes occurring since the record was closed in the first phase of the proceeding. *Id.* BPA's Amended and Supplemental Proposals did not require that every issue that was debated and decided in the May Proposal be reexamined. *Id.* Many of those issues are not germane to the cost recovery problem that the Amended and Supplemental Proposals were initiated to address. *Id.*

In BPA's August 31, 2000, letter to customers and interested parties, the BPA Administrator described the criteria BPA used to determine the appropriate approach to solving this cost-recovery problem. *Id.* The criteria for the proposed solution were:

1. It should be as simple as possible;
2. It should allow Subscription contract signing to proceed to completion as soon as possible;
3. It should not require review or revision of the overall Subscription Strategy;
4. Specifically, reallocation of Subscription power among customer groups, or a change in the basic balance of interests in Subscription should not be required;
5. It should require limited revisions, if any, to the 2002 rate proposal currently before FERC, and limited revisions, if any, to the Subscription contract; and
6. It must achieve the goal of leaving BPA's probability of repaying the U.S. Treasury, in full and on time, within an acceptable range over the 2002-2006 rate period.

*Id.*; Burns and Berwager, WP-02-E-BPA-70, at 6. Once the decision had been made to pursue adjustments to BPA's CRAC and to make corresponding changes in the Slice methodology, BPA developed the Amended and Supplemental Proposals, which met the foregoing criteria. Burns and Berwager, WP-02-E-BPA-62, at 2-6. These criteria formed the basis of the policy objectives to be implemented in the rate proceeding. *Id.* Another objective was that the solution needed to be in place when current rates and contracts expire on September 30, 2001. *Id.* Notably, the DSIs have made no effort to demonstrate that their proposal would accomplish the policy objectives that BPA has consistently advocated, or to explain why those policy goals are no longer valid. *Id.* Indeed, the DSI proposal appears inconsistent with some of these goals.

During the rate hearing, the DSIs argued that the fact that BPA was somewhat uncertain on the precise level of its previously unanticipated costs provided no basis for ignoring the costs in connection with the rate directives and that all of BPA's revenue requirement is based on forecasts and there is always some uncertainty in the accuracy of forecasts. Schoenbeck and Bliven, WP-02-E-DS-06, at 4. First, it should be noted that the DSIs thus acknowledged that BPA is uncertain of the precise level of the previously unanticipated costs that have appeared since BPA's May Proposal. Ebberts, *et al.*, WP-02-E-BPA-79, at 3-4. More importantly, although it is true that BPA's revenue requirement is based on forecasts which always contain some uncertainty in their accuracy, the uncertainty BPA has encountered historically in developing its prior wholesale power rates is dramatically different from the uncertainty BPA faces in developing its current rates. *Id.* For example, in BPA's 1996 rate case, BPA forecasted that it could serve loads with existing resources plus a small amount of balancing purchases that could be purchased in a relatively stable power market. *Id.* In contrast, BPA's load obligation for the Fiscal Year 2002-2006 rate period far exceeds existing resources and BPA now faces the likelihood of purchasing as much as 3,305 aMW of system augmentation in addition to balancing purchases. *Id.* In a volatile power market, the cost of these purchases could be subject to extreme variations. *Id.* These dramatic differences support BPA's current risk mitigation approach which deals with the problem in a flexible manner. *Id.* The flexibility inherent in the design of the risk mitigation package avoids a great deal of the risk of under-recovery or over-recovery that could result from locking in highly uncertain and variable augmentation costs based on a forecast developed prior to the rate period. *Id.*

BPA's proposed approach provides an appropriate degree of flexibility in dealing with a cost-recovery problem that involves a very high degree of uncertainty. Burns and Berwager, WP-02-E-BPA-62, at 5-6. Current price volatility resulted in forward market prices exceeding the forecasts used to develop the May Proposal. *Id.* BPA does not believe redoing all of the forecasts is the best policy choice to address current market volatility. *Id.* BPA's proposed approach, which does not involve revision of revenue requirements, base rates, or other measures, is a fairer and more prudent approach than resetting rates in a time of uncertain markets. *Id.* These reasons are also reflected in BPA's supplemental policy testimony. Burns and Berwager, WP-02-E-BPA-70, at 6. To the extent the DSIs argue that the record of BPA's Supplemental Proposal alone does not demonstrate compliance with BPA's rate directives, the portion of the rate case record that relates only to BPA's Supplemental Proposal is merely one part of the entire administrative record. Ebberts, WP-02-E-BPA-79, at 3. Any suggestion that the limited record of the Supplemental Proposal should be the only part of the record to be reviewed in determining BPA's compliance with rate directives clearly lacks merit. *Id.*

The DSIs argue that BPA attempts to excuse its failure to implement the rate directives by pointing to the studies it did during hearings on the May Proposal as adequately demonstrating compliance with the rate directives. *See* Ebberts, *et al.*, WP-02-E- BPA-79, at 4. DSI Brief, WP-02-B-DS/AL-02, at 38; DSI Ex. Brief, WP-02-R-DS/AL-02, at 2-4. The DSIs argue that there were serious flaws with those studies identified by the DSIs in testimony and briefs filed during the May Proposal phase of this proceeding. DSI Brief, WP-02-B-DS/AL-02, at 38. In response, however, these alleged "flaws" are thoroughly reviewed in the record of BPA's May Proposal, which is part of the record of BPA's WP-02 rate proceeding, and are expressly addressed in BPA's May Proposal Record of Decision, WP-02-A-02. The DSIs also argue that BPA's May Proposal studies are not based on the costs and loads that form the basis of the Supplemental Proposal. *Id.* In response, it is important to note that BPA's Supplemental Proposal does not propose to develop new rate schedules from square one. BPA's Supplemental Proposal advocates adopting risk mitigation measures that will help ensure that BPA's existing base rates will recover BPA's costs in a time of volatile energy markets. It is appropriate that such rate mitigation measures be based upon the most current forecasts available. This does not, however, require that BPA return to square one and incorporate later forecasts in conducting a complete redevelopment of BPA's base rates. BPA's development of rate mitigation measures is a reasonable approach that is consistent with the requirements of the Northwest Power Act. BPA's forecasts of loads and costs are constantly changing. Normally, despite these inevitable changes, rates can be developed using point forecasts that are expected to provide a reasonable basis for rate development. As noted previously, however, the uncertainty BPA has encountered historically in developing its prior wholesale power rates is dramatically different from the uncertainty BPA faces in developing its current rates. Ebberts, *et al.*, WP-02-E-BPA-79, at 3-4. The flexibility inherent in the design of the risk mitigation package avoids a great deal of the risk of under-recovery or over-recovery that could result from locking in highly uncertain and variable augmentation costs based on a forecast developed prior to the rate period, *id.*, or even later forecasts. This is consistent with an important rate directive in the Northwest Power Act. Section 7(a)(1) of the Northwest Power Act provides that:

The Administrator shall 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. Such rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the [Administrator's costs] . . .

16 U.S.C. § 839e(a)(1). Similarly, section 7(a)(2) of the Northwest Power Act provides that FERC shall confirm and approve BPA's wholesale power rates based on a finding that such rates "are sufficient to assure repayment of the federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs, [and] are based upon the Administrator's total system costs . . ." 16 U.S.C. § 839e(a)(2). Thus, one of the most important rate directives is to ensure that the proposed rates recover BPA's costs. The addition of rate mitigation measures to BPA's base rates helps greatly in meeting this requirement.

BPA's rate mitigation proposal is also consistent with another important rate directive. Section 9 of the Federal Columbia River Transmission System Act, 16 U.S.C. § 838g, provides that "[s]uch [BPA] rate schedules shall be fixed and established (1) with a view to encouraging the widest possible diversified use of electric power *at the lowest possible rates to consumers consistent with sound business principles . . .*" (Emphasis added.) See 16 U.S.C. § 825s. BPA's proposed rate mitigation measures, in conjunction with BPA's base rates, allow BPA to more accurately recover its true costs from customers by using the CRACs to determine BPA's actual costs during an extremely volatile period in the electric power industry. Because BPA is required to recover its costs, the recovery of costs through adjustment clauses helps to keep BPA's rates as low as possible consistent with sound business principles.

The DSIs argue that BPA also attempts to excuse its failure to implement the rate directives by choosing, as a matter of policy, to rely on adjustment clauses to assure cost recovery and choosing not to conduct a new rate case. DSI Brief, WP-02-B-DS/AL-02, at 38; DSI Ex. Brief, WP-02-R-DS/AL-02, at 2-4. The DSIs acknowledge that they do not contend that the rate directives preclude BPA from developing adjustment clauses, such as the various CRAC proposals in this case, to assure cost recovery. *Id.* The DSIs note that these are simply different rate designs, and section 7(e) of the Northwest Power Act gives BPA broad authority to adopt various rate forms and rate designs. *Id.* However, the DSIs argue that section 7(e) does not give BPA authority to avoid the other rate directives. *Id.* The DSIs cite the legislative history of section 7(e):

This subsection [7(e)] also clarifies that the rate directives contained in this bill only govern the amount of money BPA is to collect from each class of customer and not the form of the rate used to collect that sum of money. For example, time-of-day rates, seasonal rates, rate structures designed to give BPA customers particular price signals, and other rate forms would be permissible.

H. Rep. No. 976, 96<sup>th</sup> Congress, 2d Sess., Pt. 2 at 53 (1980). DSI Brief, WP-02-B-DS/AL-02, at 38. BPA, however, has never claimed that section 7(e) provides BPA with the authority to avoid BPA's other rate directives. Section 7(e) simply provides BPA with broad discretion in the design of BPA's rates. BPA has satisfied the Northwest Power Act's rate directives by following each such directive in developing its proposed base rates. As discussed previously,

these are documented in the administrative record, primarily in the record supporting BPA's May Proposal. *See also* 16 U.S.C. § 839e(i)(4).

The DSIs argue that with respect to the rate directive that received by far the most attention by Congress during deliberations over the Northwest Power Act, the section 7(b)(2) rate test, BPA stated as follows:

While the DSIs propose only a limited number of changes, performing the section 7(b)(2) rate test again would require BPA to review all of its inputs as well as policy, technical, and legal issues. *Given these variables, one cannot accurately predict the results of the section 7(b)(2) rate test in the event the test were conducted anew.*

Ebberts, *et al.*, WP-02-E-BPA-79, at 9 (emphasis added). DSI Brief, WP-02-B-DS/AL-02, at 38. The DSIs argue that this is precisely their point and it is equally true with respect to the section 7(c) rate directives. *Id.* The DSIs argue that BPA has no idea whether its Supplemental Proposal is consistent with the law because it did not bother to check. *Id.* The DSIs, however, have quoted the passage from BPA staff's testimony out of context. The BPA testimony was addressing what would result from BPA staff's understanding of the DSIs' proposal if BPA were to make only the adjustments desired by the DSIs and were only to rerun the studies that might affect the DSI rate, instead of conducting an entirely new rate case. *See* Ebberts, *et al.*, WP-02-E-BPA-79, at 9. BPA was pointing out that such a proposal was unfair to BPA's other customers as it precluded other customers from revisiting issues that might bear directly on their rates and the DSIs' rates. *Id.* BPA staff noted that BPA cannot simply pick and choose issues and studies that favor the DSIs when developing rates. *Id.* BPA staff pointed out that, given that all issues would be open for determination in a completely new rate case, there would be myriad variables that would preclude predicting the outcome of the 7(b)(2) rate test. *Id.* This situation would only occur, however, if BPA conducted an entirely new rate case, which BPA staff did not believe was being advocated by the DSIs, as noted below, nor was it being advocated by BPA. *Id.* The fact that BPA cannot predict the result of the section 7(b)(2) rate test in the event that the rate test was conducted with new, unknown inputs, is intuitively obvious, but it does not demonstrate that BPA has ignored whether its rate proposal complies with BPA's rate directives.

As noted above, BPA staff's understanding of the DSIs' position was that the DSIs argued that the only manner in which BPA can address the unprecedented volatility of market prices and loads in its ratemaking is through making the limited adjustments advocated by the DSIs and rerunning certain determinations such as the section 7(b)(2) rate test, the IP-PF link and the section 7(c)(2) floor rate test. Schoenbeck and Bliven, WP-02-E-DS-06, at 5. The DSIs, however, did not appear to BPA staff to argue that BPA should conduct an entirely new rate case. *Id.* BPA staff understood the DSIs' suggestion to be that BPA should "redo" only the ratemaking elements that might contribute to the development of a more favorable IP rate. Ebberts, *et al.*, WP-02-E-BPA-79, at 5-6. If BPA were to accept this proposal, BPA's studies would not be the only elements of rate development reviewed by BPA. *Id.* There are hundreds of issues in every BPA rate case that must be decided by the agency, including policy, technical, and legal issues. *Id.* If BPA were to revise studies as proposed by the DSIs, BPA would also properly review other issues that could significantly affect the results of those studies. *Id.* For example, BPA would likely review the issue of the DSI margin. *Id.* Similarly, BPA would

review the manner in which the costs of the section 7(b)(2) rate test are allocated to other power rates, including the DSIs. *Id.* BPA would likely review the manner in which market costs are reflected in the Industrial Firm Power Targeted Adjustment Charge rate, and so on. *Id.* BPA staff's understanding of the DSIs' limited approach would not be a proper way to develop rates. Instead, rates would need to be developed from the ground up. *Id.* BPA's approach of developing flexible risk mitigation tools avoids this complication. *Id.* The base rates are not changed, and the risk mitigation package is designed to make sure that customers are assigned an appropriate share of actual augmentation costs. *Id.* This concept is reflected in BPA's policy testimony, which concludes that the most appropriate method for addressing existing market uncertainties is through BPA's risk mitigation approach. *Id.*

In their brief on exceptions, the DSIs argue that BPA incorrectly claims that the DSIs have recommended that, in developing new rates, BPA should only address selected rate directives that benefit the DSIs. DSI Ex. Brief, WP-02-R-DS/AL-02, at 3. BPA did not intend to mischaracterize the DSIs' position. In BPA's supplemental rebuttal testimony, BPA staff stated their understanding that the DSIs were advocating only limited changes to a new BPA rate case. Ebberts, *et al.*, WP-02-E-BPA-79, at 5-6. During cross-examination, the DSIs did not question BPA's characterization. Nevertheless, BPA accepts the DSIs' characterization of its claims. In any event, however, the DSIs' proposal would make its adoption highly problematic from a practical standpoint. *Id.* In developing an initial rate proposal, more time is needed by BPA staff to develop the proposal prior to beginning the formal hearing portion itself. *Id.* For example, BPA staff's work on BPA's initial WP-02 rate proposal took approximately 10 months. *Id.* After preliminary staff work had been completed, BPA conducted informal workshops with interested parties. *Id.* These informal workshops provided BPA with input from customers and others to shape BPA's initial proposal. *Id.* The formal hearing portion of the WP-02 rate development took approximately nine months. *Id.* Thus, it would not be surprising if a new general wholesale power rate case to consider the DSIs' proposal took as long as 19 months. *Id.* In order to implement new power sales contracts, however, BPA must file its current proposed rates with FERC no later than the end of June 2001. *Id.* BPA cannot simply extend its current rates because those rates do not contain some of the new rate schedules needed to implement BPA's new subscription contracts (*e.g.*, the Residential Load (RL) and PF Exchange Subscription rates). *Id.* Moreover, there has been no demonstration that BPA's current rates would fully recover BPA's costs given current market conditions. *Id.* Under the DSIs' proposal, BPA would not have sufficient opportunity to develop an acceptable proposal along the lines envisioned by the DSIs. *Id.*

In their brief on exceptions, the DSIs argue that in all prior rate proceedings conducted under section 7(i) of the Northwest Power Act, BPA has incorporated into its final studies all of the changed circumstances that developed before the record closed, citing BPA's WP-96 rate proceeding. DSI Ex. Brief, WP-02-R-DS/AL-02, at 4. In response to this argument, it should be noted that none of BPA's previous rate proceedings under section 7(i) of the Northwest Power Act involved circumstances like those presented in the current rate case. *See* Burns and Berwager, WP-02-E-BPA-62; Burns and Berwager, WP-02-E-BPA-70; Tr. 147. BPA has previously documented the unique circumstances that confronted BPA during its current rate development. In short, subsequent to filing BPA's May Proposal with FERC in July 2000, during the late spring and summer months, the West Coast power markets suffered price increases and volatility that had not been seen before. Burns and Berwager, WP-02-E-BPA-62,

at 2. By August, it was clear that these market prices were not a short-term phenomenon. *Id.* Escalating and more volatile market prices had two related effects. *Id.* First, the specter of higher prices and continued unpredictability caused customers to place as much load as possible on BPA. *Id.* Second, to meet this increased load obligation, BPA needed to make substantially greater power purchases at substantially higher and more uncertain prices than anticipated in the May Proposal. *Id.* BPA concluded that the May Proposal, as filed with the FERC, was not adequate to deal with the added costs and financial risks that the high and volatile market prices created for BPA. *Id.* This caused BPA to file an Amended Proposal incorporating more recent price and load forecasts. The increasing and volatile market prices that prompted the Amended Proposal, however, did not stop there. Shortly thereafter, market prices available for power during the first two years of the rate period were significantly higher than BPA had forecast in the Amended Proposal. Burns and Berwager, WP-02-E-BPA-70, at 2. Market prices during the first years of the rate period ranged from \$200/megawatthour (MWh) to \$240/MWh for FY 2002, and then dropped during the last years of the rate period to a range between \$40/MWh and \$60/MWh in FY 2006. *Id.* at 4. This compared with a risk-adjusted expected price forecast in the Amended Proposal for the five-year rate period around \$48/MWh, where expected prices for individual years did not vary by more than \$5/MWh from the \$48/MWh average. *Id.* These dramatic changes required BPA to develop a Supplemental Proposal. In prior rate cases, BPA was reasonably confident about its rate case forecasts. *See* Administrator's Final Record of Decision, WP-96-A-02, *e.g.*, Chapter 3.0. In the WP-02 rate proceeding, however, loads and market prices are extremely volatile and cannot be accurately captured by point forecasts for purposes of rate development. BPA needed to address this circumstance in a manner that was consistent with law, including the critical requirement that BPA's rates recover its costs, and in a timely manner. This is what BPA did through the development of rate mitigation measures included in BPA's Supplemental Proposal.

The DSIs argue that in BPA's WP-96 rate proceeding, BPA completely revised many of its major assumptions in December of 1995 and reflected new data in studies that were issued on June 17, 1996. DSI Ex. Brief, WP-02-R-DS/AL-02, at 4. The DSIs have provided no citation to authority to support this claim. Regardless, however, the "complete revisions" of major assumptions cited by the DSIs simply refers to BPA's 1996 supplemental proposal. The "reflection of new data in studies" simply refers to the final studies that BPA prepares at the end of every rate case. Unfortunately, the DSIs have failed to elaborate further on the nature of BPA's WP-96 rate proceeding, which clearly differentiates it from BPA's WP-02 proceeding. At a prehearing conference held on March 22, 1995, the hearing officers issued a procedural schedule for both BPA's 1995 rate case and BPA's 1996 rate case. *See* Order Establishing Schedules, WP-95-O-05 and WP-96-O-05. The schedule provided that BPA would file its initial proposal in the WP-95 rate case, including all studies, on May 1, 1995. The schedule also noted that BPA would file its initial WP-96 rate proposal, including all studies, on July 10, 1995. More importantly, while BPA filed its initial WP-96 rate proposal on July 10, 1995, the schedule for that proceeding *already* provided that a later supplemental proposal would be filed on October 25, 1995. The October 25, 1995, date was later extended to December 8, 1995. *See* Order Amending Schedule, WP-96-O-25. Thus, because BPA's initial WP-95 studies were so similar to BPA's WP-96 studies, BPA essentially had from May 1, 1995, until December 8, 1995, to prepare revised studies that supported BPA's WP-96 supplemental proposal, which had already been planned for approximately eight months. In the WP-96 rate case, BPA's supplemental proposal, from the beginning, was simply incorporated into the existing procedural

schedule. The remainder of the procedural schedule that followed the filing of the supplemental proposal continued from December 8, 1995, through June 20, 1996, a period of approximately six additional months, in addition to the five previous months of the evidentiary hearing.

The foregoing schedule contrasts sharply with the circumstances in BPA's WP-02 rate case. First, BPA's WP-02 rate case was conducted and completed in its entirety before BPA was aware that it needed to revise its rate proposal. BPA had already established base wholesale power rates in its May Proposal, and had issued a final ROD. BPA, however, did not determine whether to file an Amended Proposal until August 31, 2000, when BPA announced its intent to do so. BPA filed its Amended Proposal, which contained risk mitigation measures, on December 12, 2001. Due to the tremendous volatility and upward direction of market prices, however, BPA's Amended Proposal soon was insufficient to meet BPA's cost recovery needs. Thus, on February 15, 2001, BPA published its Supplemental Proposal, with revised risk mitigation measures. If, instead of proceeding with risk mitigation measures in BPA's Amended Proposal, BPA had prepared a completely new initial proposal instead (which would have been substantially different than BPA's Amended Proposal), BPA's initial proposal could not have been completed by December 12, 2001. If, as proposed by the DSIs, BPA had gone back to square one and developed new data, forecasts, studies, testimony, etc., then there would have been significant preparatory time required prior to filing the new initial proposal. As noted in BPA staff's testimony, BPA spent approximately 10 months preparing BPA's WP-02 initial proposal. Ebberts, *et al.*, WP-02-E-BPA-79, at 6. Furthermore, BPA's work on a new initial proposal would have been interrupted by the need to develop new forecasts to reflect the changes in the market that required BPA to file its Supplemental Proposal, extending the time even further for the preparation of BPA's new initial proposal. In addition, contrary to the WP-96 rate case where BPA, from the beginning, had incorporated a supplemental proposal into the procedural schedule, BPA would have had to conduct a full evidentiary hearing from start to finish. BPA staff's testimony noted that it took approximately nine months to conduct the evidentiary hearing for BPA's May Proposal. *Id.* Also, in order to implement new power sales contracts, BPA has to file its proposed WP-02 rates with FERC no later than the end of June 2001. *Id.*

In summary, if, as suggested by the DSIs, BPA had attempted to conduct a completely new rate case starting with a decision to do so on August 31, 2000 (the date when BPA decided to file an Amended Proposal), BPA would have required approximately ten months for preparation of the technical work supporting a new initial proposal, including the development of new data, forecasts, studies, testimony, etc. (This ignores the additional work and subsequent delay of the initial proposal that would have occurred when BPA's preparation of the new initial proposal would have had to be redone to reflect the additional market changes that were the cause of BPA's Supplemental Proposal.) This 10-month period beginning September 1, 2000, would have ended on July 1, 2001. This date, however, is when BPA must have filed its final WP-02 rates with FERC. This date also does not even include the additional nine months that would be required to conduct a completely new evidentiary hearing on the new initial proposal. Adding the time required for the evidentiary hearing phase of the new WP-02 rate proceeding, BPA would not be able to issue its final ROD until April 1, 2002. This would be long after BPA's rates had to be in effect for the implementation of BPA's subscription contracts with its customers, which begin on October 1, 2001. Even if BPA were able to prepare a completely new initial proposal in less than ten months, there would still be insufficient time in which to conduct



a full evidentiary hearing. Thus, contrary to the DSIs' argument, it is not simply "BPA's own choice" that prevented it from conducting a completely new rate case and updating BPA's final studies with new forecasts and assumptions.

Furthermore, even assuming for the sake of argument that BPA had enough time to begin a new rate case from square one, this would not mean that BPA's current proposed risk mitigation approach is wrong. There may be a number of ways in which BPA could have proceeded to revise its rates to address the problems of uncertainty and volatility in the power market. BPA determined, after a thorough review, that it is appropriate to deal with a problem of uncertainty with risk mitigation tools. This allowed BPA to comply with its rate directives and use its base rates, which are supplemented by risk mitigation measures, to ensure that BPA's rates recover BPA's costs. The development of these risk mitigation measures is clearly consistent with the Northwest Power Act's direction that nothing in the statutory chapter of the 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.*" (Emphasis added.) BPA's rate mitigation measures are such "other rate forms."

Finally, the rate development process must take into account the fact that BPA cannot continually revise a rate proposal to reflect new conditions. *Id.* This does not imply that the DSIs advocate revising studies after this docket closes. Instead, the DSIs' proposal argues that BPA should incorporate certain specific assumptions regarding loads and market prices. If this approach had been taken at the time BPA filed its Amended Proposal, the market price forecast used for the development of rates would have been woefully wrong. As noted in BPA's testimony, market prices increased dramatically, from approximately \$48/MWh to over \$200/MWh for the first years of the rate period. Burns and Berwager, WP-02-E-BPA-70, at 2. The point is that, in a volatile market environment, BPA's forecasts could change drastically within a few months and thereby undermine the basis for BPA's rates. *Id.* The DSIs' approach would virtually ensure that BPA's rates would be developed on incorrect assumptions.

The DSIs and SUB argue that BPA should redo the section 7(b)(2) rate test. Schoenbeck and Bliven, WP-02-E-DS-06, at 5; SUB Brief, WP-02-B-SP-02, at 7; SUB Ex. Brief, WP-02-R-SP-02, at 5-7. The DSIs state that the public agency loads to be placed on BPA exceeded BPA's May estimate by 1,472 aMW and that this change in public agency load, combined with the additional resource augmentation required to serve this load, necessitates recomputing load and resource balances and performing the section 7(b)(2) rate test to ensure compliance with the Northwest Power Act's rate directives. Schoenbeck and Bliven, WP-02-E-DS-06, at 5. The DSIs' and SUB's argument has been addressed in BPA's policy testimony, which explains why BPA is proceeding with changes in its risk mitigation strategy instead of conducting a completely new rate case. *See* Burns and Berwager, WP-02-E-BPA-62; Burns and Berwager, WP-02-E-BPA-70. Ebberts, *et al.*, WP-02-E-BPA-79, at 7. In addition, as noted above, BPA's proposed rates comport with BPA's rate directives; BPA has developed an appropriate policy approach to address the unprecedented volatility in the electric power market (*see* Burns and Berwager, WP-02-E-BPA-62; Burns and Berwager, WP-02-E-BPA-70); BPA is facing unprecedented uncertainty in the development of its rates; BPA has properly performed all of its rate studies; assuming that BPA were to revise its rate studies, BPA would also review all other policy, technical, and legal issues regarding the development of rates; BPA lacks the time necessary to conduct a completely new rate case; and there must be some end to the

incorporation of changed conditions in rates in order to conclude the rate development process and such a solution must work in a volatile market. *Id.* These reasons militate against conducting a second section 7(b)(2) study, or other studies, which essentially would require BPA to conduct a completely new rate case. *Id.*

The DSIs argue that given the steep increases in BPA's resource costs, it is unlikely that the rate test would trigger, in which case net exchange benefits would be at least \$350 million. Schoenbeck and Bliven, WP-02-E-DS-06, at 6-7. The DSIs alternatively argue that if the rate test continued to trigger, all REP benefits and costs could be eliminated entirely. *Id.* There are many variables and inputs into the section 7(b)(2) rate test. Ebberts, *et al.*, WP-02-E-BPA-79, at 9. The DSIs argue that this single matter, the section 7(b)(2) rate test, could change BPA's costs by hundreds of millions of dollars and BPA has failed to comply with the rate directives. Schoenbeck and Bliven, WP-02-E-DS-06, at 7. In response, however, BPA has conducted the section 7(b)(2) rate test and has incorporated the results of the rate test into BPA's proposed rates. *See, e.g.*, 2002 Final Power Rate Proposal, Administrator's Record of Decision, WP-02-A-02, at 13-1 to 13-63, and materials cited therein. Ebberts, *et al.*, WP-02-E-BPA-79, at 9.

In their initial brief, the DSIs claim that BPA has mischaracterized their position as somehow suggesting that the 7(b)(2) rate test (or any other statutory rate directive) must be constantly rerun. DSI Brief, WP-02-B-DS/AL-02, at 39. The DSIs argue that they contend only that compliance with both the 7(b) and 7(c) rate directives must be measured using the facts that constitute the basis for BPA's final rate determination. *Id.* BPA's rate proposal in this Final Supplemental ROD, however, would not establish simple, fixed rates. This rate proposal will use BPA's base rates from its May Proposal and the risk mitigation measures developed in the supplemental rate proceeding. BPA did not use new forecasts in developing new fixed rates, but rather in the development of risk mitigation measures for purposes of ensuring cost recovery in a volatile market environment. In addition, the DSIs propose that BPA should use forecasted load and power cost numbers that are different than those used in BPA's May Proposal. While the DSIs claim that BPA should use numbers from BPA's Supplemental Proposal, these numbers would still be point estimates that would likely change quickly in the current volatile market. This is what raises the question of where these changes should stop. In a very short time, BPA's forecasted load and power cost numbers used in the development of risk mitigation measures, given the volatility and high nature of market prices, may be dramatically different. As noted above, the DSIs' position thus would likely result in rates developed on what would almost certainly be incorrect loads and power costs. BPA's approach, which uses CRAC risk mitigation tools, avoids this significant shortcoming.

SUB argues that BPA is statutorily required to conduct a section 7(b)(2) rate test which reflects the cost of increasing the IOUs' financial benefits by using \$38/MWh instead of \$28.1/MWh. SUB Brief, WP-02-B-SP-02, at 7; SUB Ex. Brief, WP-02-R-SP-02, at 5-7. This argument is not persuasive for many of the reasons previously stated. Also, BPA is not precluded from conducting a section 7(i) hearing in order to develop risk mitigation measures that supplement BPA's base rates. 16 U.S.C. §§ 839e(i); 839e(i)(4). Furthermore, SUB's argument is inconsistent with the manner in which BPA developed its wholesale power rates in its May Proposal. *See* 2002 Final Power Rate Proposal, Administrator's Record of Decision, WP-02-A-02, at 12-12 to 12-14, and materials cited therein.

In its brief on exceptions, SUB argues that BPA incorrectly linked SUB's argument regarding section 7(b)(2) with the DSIs' argument regarding section 7(b)(2). SUB Ex. Brief, WP-02-R-SP-02, at 5-7. BPA did not intend to do so. BPA noted that there were similar responsive arguments that applied to the arguments of both SUB and the DSIs regarding section 7(b)(2). This does not mean that all such arguments apply equally to both parties' arguments. The following discussion will hopefully clarify BPA's previous response to SUB's arguments. SUB's basic argument is that BPA proposes to deviate from the May Proposal and increase IOU financial benefits, resulting in increased costs to preference utilities, and that BPA therefore must perform another section 7(b)(2) rate test. SUB Ex. Brief, WP-02-R-SP-02, at 7. First, while SUB argues that BPA's previous citation to Chapter 12 of the May Proposal ROD addresses only load and resource decisions in the Rate Design Step, Chapter 12 also addresses BPA's use of the Rate Design Step and the Subscription Step in BPA's May Proposal. In order to establish rates that reflected BPA's Subscription Strategy, changes and additions were made to the Rate Analysis Model (RAM) in BPA's May Proposal. 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 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. 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, including the section 7(b)(2) rate test. *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.* The NR-02 rate and the PF Exchange Program rate are established in the Rate Design Step of the RAM. *Id.* at 16.

The second step, the Subscription Step, takes the results of the Rate Design Step and adjusts them by the added credits and costs associated with BPA's Subscription Strategy policies, thereby producing rates for Subscription sales. Doubleday, *et al.*, WP-02-E-BPA-18, at 16. BPA's Subscription Strategy contains alternative ways in which BPA may sell power to its customers. *Id.* 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.* However, regional utilities may continue participation in the REP, and BPA must have a rate to apply to the REP. *Id.* That rate is the PF Exchange Program rate. *Id.*

SUB fails to distinguish between REP benefits under the Residential Purchase and Sale Agreement (RPSA) and the IOUs' monetary benefits under the REP Settlement Agreements. As noted above, the section 7(b)(2) rate test is performed in the Rate Design Step of the RAM, and is a key step in determining the levels of the PF Preference and PF Exchange Program rates. The PF Exchange Program rate applies to the calculation of REP benefits for public agencies and IOUs. In the May Proposal, BPA calculated a PF Exchange Program rate to be used for any utility that may participate in the REP. At the time of the May Proposal, BPA also was uncertain as to whether the IOUs would execute the REP Settlement Agreements or stay with the REP. Even now, while the IOUs have elected to participate in the REP settlements, BPA notes that parties from all three of BPA's customer groups have filed challenges to these agreements. *See*

*Portland General Electric Co. et al., v. Administrator, Bonneville Power Administration*, Ninth Circuit Case No. 01-70003. In the event that the REP Settlement Agreements were successfully challenged, the IOUs may again participate in the REP, in which case they would pay the PF Exchange Program rate. Also, BPA recognizes that, given the dramatic changes in the electric industry, some public agency customers may be eligible to participate in the REP. In order to determine the utilities' REP benefits, BPA must establish and use the PF Exchange Program rate.

The REP settlement benefits are calculated in the Subscription Step of the RAM and are not a factor in the level of the PF Exchange Program rate, which, as stated above, is calculated in the Rate Design Step of the RAM using the section 7(b)(2) rate test. It would be illogical for the cost of the REP settlement benefits to be included in the section 7(b)(2) rate test in the RAM's Rate Design Step since that part of the RAM assumes a world without the REP settlements. Further, in the event the REP Settlement Agreements were overturned by a successful legal challenge, it is illogical that the then-reestablished REP benefits should be calculated using a PF Exchange Program rate that included the costs of those same overturned REP Settlement Agreements. Because of the clear differences between the REP benefits and the REP settlement benefits, BPA has been careful to maintain a bright line between the two.

In summary, an increase in the IOUs' financial settlement benefits from a higher rate case market price forecast would have no effect on the section 7(b)(2) rate test as performed in BPA's May Proposal. Because the section 7(b)(2) rate test is conducted in the Rate Design Step, where it is necessary to establish the PF Exchange Program rate for utilities participating in the REP, and in such step the IOUs' REP settlements do not exist, increased costs from a higher rate case market price forecast are not applicable. Therefore, it is not necessary to conduct a second section 7(b)(2) rate test.

The DSIs also argued that BPA should conduct a second section 7(c)(2) floor rate test and a second IP-PF rate link. Schoenbeck and Bliven, WP-02-E-DS-06, at 5. BPA properly conducted the section 7(c)(2) floor rate test and the IP-PF link in BPA's May Proposal as part of the ratemaking process that established the IP-02 rate. The May Proposal's base rates have not changed in BPA's Amended and Supplemental Proposals. Therefore, there is no reason to revisit the 7(c)(2) floor rate test or IP-PF link. In order to accommodate possible increased costs to serve additional loads, BPA is proceeding with changes in its risk mitigation strategy instead of conducting a completely new rate case. See Burns and Berwager, WP-02-E-BPA-62; Burns and Berwager, WP-02-E-BPA-70. BPA's policy testimony describes BPA's rate mitigation approach at length, concluding that "BPA does not believe redoing all of the forecasts is the best policy choice to address current market volatility." Burns and Berwager, WP-02-E-BPA-62(E1). See also Burns and Berwager, WP-02-E-BPA-70. BPA also has previously described the many reasons why it would be inappropriate to rerun all of BPA's studies or to conduct a completely new rate case. These reasons are also applicable here.

### **Decision**

*BPA's proposed rate mitigation measures, in conjunction with BPA's base wholesale power rates, comply with the Northwest Power Act's rate directives.*

## 7.0 WHOLESALE POWER RATE DESIGN

### 7.1 Introduction

The DSIs propose a two-tier rate structure that would make available to each customer, on a take-or-pay basis, a percentage of such customer's Subscription load priced at the base rates adopted in BPA's May 2000 Final Power Rate Proposal (May Proposal). Schoenbeck and Bliven, WP-02-E-DS/AL-01, at 6. This "Base Tier" rate purchase amount would be based upon the percent of BPA's forecasted Subscription load subject to a Cost Recovery Adjustment Clause (CRAC) that BPA can serve out of its critical water inventory plus the already purchased augmentation. *Id.* The DSIs estimate that the average size of the Base Tier would be in the range of 72.6 percent to 76.7 percent of BPA's forecasted Subscription load subject to CRAC. *Id.* at 7-9. The size range is a function of whether or not each year's May and June loads and augmentation amounts are used in the calculation and how much pre-purchased augmentation to include in the calculation. *Id.* at 7-9. The DSIs argue that the augmentation amount purchased by BPA from August 1, 2000, to January 1, 2001, should be included to increase the size of the Base Tier, even though the cost of that augmentation exceeds the cost forecasted by BPA in the May Proposal. *Id.* at 10. The DSIs argue that the small extra cost should be recovered by adjusting the parameters of the Financial-Based (FB) CRAC. *Id.* at 10.

The DSIs propose that customer purchases beyond their Base Tier allocation be made at a "Marginal Tier" rate that would be set to recover the cost of augmentation purchases needed to serve the load. *Id.* at 7. The rates charged for Marginal Tier purchases would be the monthly base rates plus a per-kilowatthour Load-Based (LB) CRAC adder such that the resultant rates would be sufficient to recover the cost of BPA's augmentation purchases for service to Marginal Tier loads in that month. *Id.* at 11. In addition, the DSIs have made provisions in their LB CRAC Tiered Rates design to accommodate the Slice product. *Id.* at 12-13.

The DSIs propose different take-or-pay treatment for the Base Tier load and the Marginal Tier load. *Id.* at 13. Each customer's Base Tier load entitlement would be take-or-pay, while their Marginal Tier load entitlement amount would not be take-or-pay unless the customer notified BPA of its intention to take some or all of its Marginal Tier power entitlement. *Id.* at 14. The DSIs argue that their tiered rate design would help BPA to shift some of the market risk to its customers for them to manage. *Id.*

### 7.2 Tiered Rates

#### Issue

*Whether the DSIs marginal-cost, tiered rates CRAC proposal should be adopted.*

#### Parties' Positions

The DSIs contend that their proposal will allow customers to get the full benefits of their own efforts to conserve power. DSI Brief, WP-02-B-DS/AL-02, at 12. They also argue that tiered

rates will reduce the long-term damage to the economy of the Pacific Northwest related to the current energy markets. *Id.* at 14. The DSIs argue that the parties' objections to tiered rates lack merit. *Id.* at 15.

The Joint Customer Group (JCG) argues that tiered rates should not be adopted in this proceeding, maintaining that implementation of the DSIs tiered rate proposal would require material revisions of the base rates adopted in the May Record of Decision (ROD). JCG Brief, WP-02-B-JCG-01, at 15.

The Northwest Requirements Utilities (NRU) argues that BPA should reject the DSI proposal for tiered rates. NRU Brief, WP-02-B-NI-03, at 12. NRU Ex. Brief, WP-02-R-NI-02, at 4. NRU calls the DSI proposal a thinly disguised effort to shift billions of dollars of cost to preference customers by a customer group that has no statutory right to service after 2001. *Id.*

The Western Public Agencies Group (WPAG) argues that the DSI tiered rate proposal is inequitable and cannot be properly implemented in this proceeding. WPAG Brief, WP-02-B-WA-01, at 12. WPAG maintains that the DSI tiered rate proposal would cause cost shifts. *Id.* Moreover, according to WPAG, the DSI tiered rate proposal presents a myriad of implementation issues that are simply impossible to deal with adequately if BPA is to have in place by October 1, 2001, rates that have been approved by FERC. *Id.* at 13. WPAG argues that implementing tiered rates now is bad public policy. *Id.* at 15. Finally, WPAG argues that tiered rates are not needed to send a price signal. *Id.* at 16.

Avista Corp (Avista), Idaho Power Company (IPC), PacifiCorp, Portland General Electric (PGE), and Puget Sound Energy (PSE) argue that the DSI tiered rate proposal should not be adopted in this rate proceeding. Brief of Avista, IPC, PacifiCorp, PGE, and PSE, WP-02-B-AC/GE/IP/PL/PS-02, at 5.

The Canby Utility Board argues that the DSI proposal is not an appropriate way to deal with the problems facing BPA. Canby Ex. Brief, WP-02-R-CA-2, at 31.

The Market Access Coalition (MAC) argues that the Administrator should reject the DSI's tiered rate proposal. MAC Ex. Brief, WP-02-R-MA-02, at 11. MAC argues that adopting the DSI tiered rate proposal would be a legally gratuitous act for which there is no basis in BPA's organic statutes. *Id.* at 1.

### **BPA Staff Position**

The tiered rate design proposed by the DSIs is predicated on a flawed first tier allocation methodology and is an inappropriate change to BPA's rate design at this time. Keep, *et al.*, WP-02-E-BPA-80, at 11. Further, the DSI tiered rates proposal is such a fundamental departure from BPA's historical rate design that BPA would be unlikely to initiate it unilaterally without the support of a regional consensus on the question of the allocations of low-cost power and other key elements. *Id.* at 15. Burns and Berwager, WP-02-E-BPA-75 at 3.

## **Evaluation of Positions**

MAC argues that the Antideficiency Act prohibits the Administrator from adopting the DSIs tiered rate proposal without prior congressional authorization. MAC Ex. Brief, WP-02-R-MA-02, at 1. MAC maintains that the Administrator cannot lawfully commit the Federal Government to the legally gratuitous action of undertaking the indefinite financial obligations inherent in the DSI rate proposal without congressional authorization, either by statute or appropriations. *Id.* at 5. MAC also argues that it is simply not possible to justify adoption of the DSI tiered rate proposal on the basis of BPA's existing ratemaking authority in the Northwest Power Act. *Id.* at 6.

MAC claims that the Administrator would be in violation of the Antideficiency Act (31 U.S.C. § 1341) were he to adopt the tiered rate proposal sponsored by the DSIs. *Id.* at 4. This defect, according to MAC, is "fatal":

... [T]he DSI's Tiered-Rate proposal subjects BPA to unknown and unascertainable risk and, therefore, violates the Antideficiency Act. If the Administrator were to adopt the DSI's Tiered-Rate proposal, the Administrator would commit to paying an indefinite sum of money to serve the DSI's for which full recovery would be even more uncertain because [full recovery is] dependent upon the contingency of other rate payers being able to pay higher energy prices to subsidize the DSI's service. Such an arrangement possesses [an] unknowable future financial obligation that is prohibited under the Antideficiency Act."

*Id.* at 8. Thus, according to MAC, the only recourse for adoption of the DSI tiered rate proposal would be to request Congressional authorization. *Id.* at 10.

Because the Administrator is rejecting the DSI tiered rate proposal for the other reasons set forth below, the issues raised by MAC are moot and need not be addressed. However, the Administrator does wish to respond, to a limited extent, to MAC's arguments regarding the Antideficiency Act. BPA's activities typically involve future risks of one kind or another, all which are to some degree, in MAC's words, "unknown and unascertainable." Nor is it particularly unusual for BPA to be committed to "paying an indefinite sum of money" which is based on the "contingency" of collecting that sum from rate payers in the future. In this regard, any doubt about the Administrator's ability to incur obligations in advance of appropriations was removed by a 1988 amendment to the Transmission Act, which states: "Without fiscal year limitation, the Bonneville Power Administration continues to be authorized to incur obligations for authorized purposes and may do so in excess of borrowing authority and cash in the Bonneville Power Administration Fund." 16 U.S.C. § 838(i). This provision provides the Administrator with far more flexibility than MAC recognizes in the context of incurring obligations as a result of the ratemaking process.

The DSIs argue that their tiered rate proposal is superior from the standpoint of economic efficiency because it forces customers to face marginal-cost prices for their marginal use of electricity. DSI Brief, WP-02-B-DS/AL-02, at 12-13, citing WP-02-E-DS/AL-02, at 4. According to the DSIs, when consumers face marginal costs, they will adjust their consumption

to the point where the value to them of such consumption is equal to the price they pay. *Id.* at 13. The DSIs go on to argue that because the customer facing marginal costs will reap the full benefit of conservation and/or pay the full cost of waste, this promotes cost-effective conservation efforts and discourages wasteful uses of energy. *Id.*

The JCG argues that the DSI testimony concerning the superior economic efficiency of the DSI tiered rate proposal applies economic theory in a highly selective manner that results in two flaws. Brattebo, *et al.*, WP-02-E-JCG-03, at 8. The JCG argues that the DSI proposal only addresses allocative efficiency and does not address the implications for productive efficiency. *Id.* The JCG argues that marginal-cost pricing is a method to achieve both forms of efficiency, by ensuring that consumers use the appropriate amount of a good relative to their use of other goods (allocative efficiency) and that producers use the appropriate amount of an input relative to their use of other inputs (productive efficiency). *Id.* at 8-9. In addition, the JCG argues that the DSI proposal omits any discussion of the “theory of second best.” *Id.* at 11.

The JCG argues that while the DSI proposal discusses in very broad terms the efficiency implications of marginal-cost pricing, it omits any discussion of the implications for the efficiency of electricity use by smelters in the Northwest relative to other uses. Brattebo, *et al.*, WP-02-E-JCG-03, at 9. The JCG states that productive efficiency dictates that the value added by using electricity in the production of a good or service should equal or exceed its marginal cost, which is the price in the market. *Id.* The JCG goes on to state that if the value added at any point is less than the market price or marginal cost, then society is worse off by the use of electricity at that point. *Id.* at 9 and 10. The JCG calculates that at current aluminum market prices and electricity market prices it would take \$2,900 worth of electricity to produce \$1,400 to \$1,650 worth of aluminum. *Id.* The JCG concludes that from a purely economic perspective, under current market conditions, society as a whole will be better off if the limited supplies of electricity are allocated to higher-value uses than aluminum production. *Id.* at 11.

The JCG argues that while the DSIs offer economic arguments in favor of their tiered rate proposal, it has been clearly shown that economic theory (the theory of second best) supports an opposite conclusion. JCG Brief, WP-02-B-JCG-01, at 16. The JCG states that economic theory concludes that if prices are set at marginal costs, “optimal” consumption will occur; conversely, if prices deviate from marginal cost, “suboptimal” consumption will occur. Brattebo, *et al.*, WP-02-E-JCG-03, at 11. The JCG states that BPA power is sold to recover cost rather than at market. *Id.* at 12. The JCG argues that economic theory suggests that BPA power should be sold at a level where it causes the least change in consumption patterns from those which would occur if the power were priced at market levels. JCG Brief, WP-02-B-JCG-01, at 16. The JCG discusses Ramsey pricing theory as a way to achieve second best pricing when pure marginal cost pricing would over-collect the revenue requirement. Brattebo, *et al.*, WP-02-E-JCG-03, at 13. The JCG argues that Ramsey pricing theory would indicate that BPA power prices for aluminum smelters should deviate from marginal cost very little, while BPA power prices for residential customers should deviate from marginal costs much more. *Id.* The JCG argues that under the DSI tiered rate proposal DSIs would continue to operate. *Id.* at 17. The JCG argues that since it is clear that no DSIs would operate at current market prices, economic theory would argue strongly against the DSI tiered rate proposal. *Id.*



In response, the DSIs argue that so long as BPA is directed by statute to sell power at cost, and market prices are higher than BPA's cost-based prices, those receiving allocations of cost-based power may use it in ways that, viewed in the abstract, are not optimally efficient. DSI Brief, WP-02-B-DS/AL-02, at 17. The DSIs argue that there is nothing in the record to suggest that the uses that all other end-users will make of the power are more or less valuable than the market price of power, and that there is no basis to single out DSIs. *Id.*

The DSIs acknowledge that BPA uses marginal costs to shape rates for seasonality and time-of-use pricing. However, they argue that it is simply not credible to suggest that a modest variation in on-peak and off-peak prices set well below marginal cost (and generally not passed through to consumers) comes close to sending the efficient price signals that occur when rates are set to marginal costs. DSI Brief, WP-02-B-DS/AL-02, at 13. The JCG disagrees with the DSIs and argues that BPA's expected rates coming out of this proceeding will be sufficient to deliver a very robust price signal to all customers about the cost of using electricity and the benefits of conserving it. JCG Brief, WP-02-B-JCG-01, at 16.

The DSIs argue that their tiered rate proposal reduces BPA's need to purchase augmentation power by providing additional incentives for customers to conserve or to elect to meet power needs above Base Tier loads through owned generation or purchases from third parties. DSI Brief, WP-02-B-DS/AL-02, at 13. The JCG argues that the DSIs proposal unfairly advantages the DSIs because they can easily reduce power consumption by idling potlines. JCG Brief, WP-02-B-JCG-01, at 16. The JCG argues that other types of BPA customer groups have no such similar flexibility, and that these customers would need to purchase power on the wholesale market, resulting in significant rate increases. *Id.* WPAG argues that while the DSI tiered rate proposal has been variously described as tiered rates, marginal cost pricing, and a conservation rate; in fact, it is a cost shift rate designed with the sole purpose of benefiting the DSIs. WPAG Brief, WP-02-B-WA-01, at 12.

The DSIs acknowledge that generally higher prices may lead to some increased conservation. However, they argue that a non-tiered wholesale rate design offers many utilities a financial disincentive to pass through market price signals to consumers.

If a utility [with requirements service] were to price some loads at market price instead of what they pay in a rolled-in BPA rate, every kWh of load reduction by the utility's customers would reduce the utility's energy-related *revenue* by about 20 cents and reduce its *bill* from BPA by about 9 cents, leaving a *financial loss* of about 11 cents.

DSI Brief, WP-02-B-DS/AL-02, at 14, citing WP-02-E-DS/AL-02, at 9.

The disincentive mentioned by the DSIs above only occurs when a tiered marginal cost retail rate design is coupled with a non-tiered wholesale rate. BPA believes that its customers will conserve power given BPA's expected non-tiered wholesale rates and non-marginal-cost-tiered retail rates. The JCG argues that the DSIs' attempt to camouflage the impact of their tiered rate proposal on other customers by calling it a "conservation rate" is disingenuous. JCG Brief, WP-02-B-JCG-01, at 16. The JCG argues that the DSI tiered rate proposal, which results in a

massive cost shift between BPA's customers, is not needed to induce the thoughtful use of electricity. *Id.*

BPA agrees that sending the appropriate price signals is a valid method for efficiently allocating a scarce resource. Keep, *et al.*, WP-02-E-BPA-80, at 11. However, the DSIs' tiered rate proposal, as described in the testimony of Schoenbeck and Bliven, WP-02-E-DS/AL-01, is an inappropriate rate design for this rate case because it would overlay a fundamentally different rate design on an existing power allocation methodology. Keep, *et al.*, WP-02-E-BPA-80, at 11. The allocation of federal power in the May Proposal was determined, in part, by the Investor-Owned Utilities (IOU) Residential Exchange Program (REP) Settlement Agreement and the DSI Compromise Approach. *Id.* Under the IOU REP Settlement, the IOUs are allocated at least 1,000 average megawatts (aMW) of federal power. *See* Burns and Elizalde, WP-02-E-BPA-08. Under the DSI Compromise Approach, the DSIs are allocated 1,486 aMW of federal power. *See* Berwager, *et al.*, WP-02-E-BPA-09. Neither of these agreements contemplated BPA's adoption of a tiered rate design with a second tier priced at market. Keep, *et al.*, WP-02-E-BPA-80, at 11. One can speculate that had the power market conditions that now prompt the DSIs to propose tiered rates existed during the IOU REP Settlement and the Compromise Approach negotiations, the current 1,000 aMW IOU allocation and the 1,486 aMW DSI allocation might have changed. *Id.*

Parties that were willing to accept this allocation under a regime that envisioned imposition of a non-tiered, average rate might not have had the same perspective, if they had believed that any allocation received would ultimately be subject to tiering on the margin. Clearly, the negotiations would have been greatly influenced by this possibility, not to mention the specter of impending power shortages and very high power market and natural gas prices. *Id.* Thus, it is highly probable that the prospect of marginal-cost tiering would have created a much different initial resource allocation scheme than the one presently proposed. It would not be equitable, therefore, to superimpose on the current allocation a tiered rate design that is not simply indifferent, but antithetical, to the original expectations of some customer groups with respect to the rate that would attach to their allocation of federal power.

The JCG makes a similar argument, maintaining that the DSI tiered rate proposal should not be adopted in this proceeding because its implementation would require a power allocation that differs from that contained in the Subscription Strategy and the ROD. JCG Brief, WP-02-B-JCG-01, at 15. The JCG argues that the implementation of tiered rates and reallocation of power are such major changes in policy, BPA would be required to conduct an extensive consultation process to elicit the views of the region. *Id.* The JCG argues that such a consultation process would need to deal with a number of significant issues and would be neither short nor harmonious. *Id.*

The JCG cites a number of reasons why implementing tiered rates in this proceeding is not appropriate. JCG Brief, WP-02-B-JCG-01, at 15. The JCG argues that implementation of the DSI tiered rate proposal would require reopening the base rates to remove the included augmentation costs, which would itself require revisiting a variety of rate design and cost allocation issues. *Id.* The JCG argues that while the modification of contingent rate adjustment clauses does not require the performance of the section 7(b)(2) rate test nor the section 7(c) floor

calculation, revising the May Proposal base rates, as would be necessitated by the implementation of the DSI tiered rate proposal, would require that both of these statutory exercises be performed. *Id.* The JCG argues that there is simply no time available to do all of this and have rates in effect by October 1, 2001. *Id.*

The DSIs argue that their tiered rate proposal will reduce the long-term damage to the economy of the Pacific Northwest. DSI Brief, WP-02-B-DS/AL-02, at 14. The DSI witness, Dr. Parmesano, believes that denying major industries in the region any low-cost power and causing them to shut down completely will delay their recovery when the supply problem is solved and this delay will have negative effects on the economy. *Id.* The DSIs argue that by permitting some level of continued operation, the tiered rate proposal would reduce significantly the likelihood that facilities are closed permanently in the Pacific Northwest. *Id.* The DSIs argue that permanently closing electricity-intensive industry in the Pacific Northwest on account of temporary price problems is not sound public policy; whereas, their tiered rate proposal gives every customer access to some low-cost power, thus allowing for some continued level of operation. *Id.* at 15.

WPAG argues that establishing public policy requires public involvement in order to gain a complete understanding of the policy to be implemented and the confidence that it will be implemented fairly. WPAG Brief, WP-02-B-WA-01, at 15. WPAG argues that before BPA could seriously consider such a major change in the manner that it prices power, principles of sound public policy require that a thorough regional dialogue be conducted to explore the benefits and detriments of such a change. *Id.* WPAG argues that such a dialogue would have to resolve, at a minimum, what constitutes a fair allocation of the existing FBS resources, whether the Northwest Power Act permits BPA to sell requirements power to preference customers under a tiered rate when there is sufficient FBS resources to serve all of their loads, and whether the DSIs and the IOUs are entitled to any FBS power at cost under a tiered rate proposal. *Id.*

The DSIs argue that the parties' objections to tiered rates lack merit. DSI Brief, WP-02-B-DS/AL-02, at 15. The DSIs state that the principal objection to the tiered rate proposal is that the Base Tier of DSI load could continue to operate. *Id.* The DSIs argue that attributing BPA's augmentation costs to the DSIs is simply self-serving rhetoric. *Id.* According to the DSIs, there is nothing unique about DSI load; a reduction in sales to the IOUs or public agencies prompted by proper rate design would have the same effect on BPA's augmentation costs as a reduction in DSI loads. *Id.* The DSIs argue that it is reasonable to infer that most if not all farms and energy-intensive businesses can curtail production to avoid the Marginal Tier, and would in fact prefer to do so rather than pay much higher prices for their entire loads so as to threaten their economic survival. *Id.* at 16.

WPAG disagrees, maintaining that the DSIs are the only BPA customer group that has the ability to reduce their loads by 25 percent. WPAG Brief, WP-02-B-WA-01, at 12. WPAG argues that as a consequence of this ability, the DSIs are the only BPA customer group that could completely avoid the costs BPA will incur to augment the FBS. *Id.* WPAG argues that under the DSI tiered rate proposal the approximately \$1.8 billion in augmentation costs that BPA will incur to serve the 1,000 aMW of DSI load will be paid entirely by BPA's public and IOU

customers. *Id.* at 13. WPAG argues that over the course of the rate period, this subsidy to the DSIs will cost BPA's other customers about \$3.4 billion. *Id.*

The DSIs argue that from the standpoint of causation, it was the unplanned-for shift of public agency load that has created the majority of BPA's cost problem. DSI Brief, WP-02-B-DS/AL-02, at 15, citing WP-02-E-DS/AL-03, at 6-7; 65 FR 75274; WP-02-E-BPA-58, at 2-5; WP-02-E-BPA-62, at 2; WP-02-E-BPA-63, at 10. The DSIs argue that their load, unlike the last-minute public load, was planned for and resulted in augmentation purchases made long before market prices reached their present levels. *Id.*

The DSIs further argue that the JCG argument that the DSI load should receive no allocation of low-cost Base Tier power, because the DSIs do not have statutory rights to low-cost BPA power, is without merit because BPA has already allocated its power by entering into Subscription contracts. DSI Brief, WP-02-B-DS/AL-02, at 16. The DSIs go on to argue that BPA allocated its costs to base rates at an earlier stage of this proceeding and the JCG proposal does nothing to change that allocation. *Id.*

The DSIs arguments in this regard ultimately work against them. While it is true that BPA has entered into contracts to provide power to the DSIs, the contracts do not speak to any kind of rate guarantee. The issues raised by the DSIs concerning issues such as statutory entitlement to power and causation with respect to augmentation costs, merely highlight the complexity of determining how any tiering of rates should be accomplished. BPA cannot simply ignore such considerations and arbitrarily impose a marginal cost tier based on no more than the DSIs' assessment of these legal and policy issues. Instead, BPA agrees with WPAG that such issues deserve careful deliberation in a public process.

The DSIs maintain further that BPA's claim that the region considered and rejected the concept of tiered rates during the Subscription Strategy process is without merit. DSI Brief, WP-02-B-DS/AL-02, at 17. The DSIs argue that the tiered rates proposal advanced by the DSIs in this proceeding was neither considered nor rejected in the Subscription Strategy process. *Id.* In BPA Rebuttal testimony, Keep, *et al.*, WP-02-E-BPA-80, BPA states "BPA has some experience in trying to reach a regional consensus on tiered rates in general and the allocation of low-cost first-tier power in particular. That experience indicates to BPA that Montana Power's optimism about a quick regional resolution may be misplaced." The rebuttal testimony refers to discussions in the mid-1990s, not during the Subscription Strategy process. However, a fair reading of the initial briefs from the JCG, WPAG, the IOU Companies, and NRU indicates to BPA that the probability of a regional consensus in favor of the DSI tiered rate proposal is quite low. *See also* the following excerpts of the Transcript of Oral Argument for statements from a wide variety of groups opposing the DSI tiered rate proposal: 27-28 and 38-39 (JCG); 45-47 (NRU); 57 (PGP); 72-73 (PPC); 77-80 (WPAG); and 84-85 (MAC).

The JCG argues that the DSIs' tiered rate proposal raises serious cost shift issues. JCG Brief, WP-02-B-JCG-01, at 16. The JCG argues that allowing the DSIs to purchase 1,000 aMW of Base Tier power at about \$23/MWh would require BPA's public and IOU customers to provide the DSIs with an annual power cost subsidy of over \$1.6 billion per year. *Id.*

WPAG argues that the DSI tiered rate proposal presents a myriad of implementation issues that are simply impossible to deal with adequately if BPA is to have in place by October 1, 2001, rates that have been approved by the FERC. WPAG Brief, WP-02-B-WA-01, at 13. WPAG argues that the DSI tiered rate proposal conflicts with the provision of the Subscription Strategy and the ROD that power sales to BPA's public utility and IOU customers would be made at the same melded rate. *Id.* WPAG argues that such a change would require the reopening of the Subscription ROD to evaluate the new approach. *Id.* WPAG argues that such a proposal would destroy any remaining support among BPA's public utility customers for the REP Settlement, and would also generate strong opposition to the sale of any power to the DSIs. *Id.*

WPAG argues that the DSI tiered rate proposal would conflict with provisions of the Subscription contracts, and that crafting the necessary amendments to accommodate a tiered rate would be both difficult and time consuming. WPAG Brief, WP-02-B-WA-01, at 14. WPAG goes on to argue that since BPA's customers signed their Subscription contracts based on the Subscription ROD that envisioned melded cost rates, there would be a demand to reopen these contracts to allow customers to reconsider their product choices. *Id.*

WPAG argues that the implementation of the DSI tiered rate proposal would require the reopening of the base rates. WPAG Brief, WP-02-B-WA-01, at 14. WPAG argues that BPA would have to rerun its forecasting models to demonstrate to FERC that this new rate design would satisfy the statutory cost recovery standard as required by Section 7(a) of the Northwest Power Act. *Id.* WPAG argues that there is little likelihood that BPA could avoid revisiting the cost allocation, classification and rate design issues decided in the first phase of this proceeding if the DSI rate proposal were adopted. *Id.* WPAG goes on to argue that there is simply not enough time available to do the work needed to put such rates into place. *Id.*

Irrespective of the merits of WPAG's arguments, they do point to the difficulties inherent in the DSI plan. Once again, BPA is led back to the inescapable conclusion that a tiered rate design like the one offered by the DSIs is impractical at this time. A great many material and procedural issues would need to be addressed with far more deliberation in order to insure the fairness and practicability of any alternative.

The JCG argues that the DSI tiered rate proposal is not a conservation proposal; it is a cost shift proposal of massive proportions. JCG Brief, WP-02-B-JCG-01, at 17. The JCG further argues that the DSIs' attempt to obtain an unprecedented rate subsidy from BPA's public and IOU customers under the guise of a conservation rate should be rejected. *Id.* Avista, IPC, PacifiCorp, PGE, and PSE (IOU Companies) argue that the DSI tiered rate proposal should not be adopted in this rate proceeding. Initial brief of Avista, IPC, PacifiCorp, PGE, and PSE, WP-02-B-AC/GE/IP/PL/PS-02, at 5. The IOU Companies support and adopt the argument of the JCG on this issue. *Id.* at 6. WPAG argues that the only clear beneficiaries of the DSI tiered rate proposal are the DSIs, who are the only group that has no statutory right whatsoever to any power from BPA at any price, and who are unwilling to step up and pay their fair share of BPA's costs in this time of need. WPAG Brief, WP-02-B-WA-01, at 17. WPAG argues that the DSI tiered rate proposal should be soundly rejected. *Id.* NRU argues that BPA should reject the DSI proposal for tiered rates. NRU Brief, WP-02-B-NI-03, at 12. NRU argues that the DSI proposal is a thinly disguised effort to shift billions of dollars of cost to preference customers by a

customer group that has no statutory right to service after 2001. *Id.* NRU argues that the DSI proposal would amount to a massive transfer of dollars to the DSIs and would be a gross violation of the “preference” clause and the rate directives in the Bonneville Project Act and the Northwest Power Act. *Id.* at 13.

Again, the concerns raised about cost shifts, regardless of their merit, and the obviously divisive nature of the issue point clearly to its rejection. BPA is not prepared to accept the DSI tiered rate proposal at this time.

**Decision**

*BPA will not adopt the DSI marginal-cost tiered rate proposal.*

## 8.0 SLICE OF THE SYSTEM PRODUCT

### 8.1 Introduction

Slice is a requirements power product that sells a fixed percentage of the energy generated by the Federal Columbia River Power System (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, the Slice product combines both the sale of requirements and surplus power.

Rather than paying a set price per megawatt (MW) and megawatthour (MWh) for the power, Slice purchasers will assume the obligation to pay a percentage of BPA's costs proportional to the percentage of the FCRPS that the Slice purchaser elects to purchase. Wholesale Power Rate Development Study, WP-02-FS-BPA-05, at 41. The costs considered for the Slice product in the Block and Slice Power Sales Agreement (Block/Slice Contract) are referred to collectively as the Slice Revenue Requirement. *Id.* The Slice Revenue Requirement is displayed in Table D, 2002 Wholesale Power Rate Schedules, WP-02-A-02, at 105-106, and is the basis for the Slice Rate. *Id.* at 7. The Slice base rate has not changed since the May 2000 Final Power Rate Proposal (May Proposal).

### 8.2 Supplemental Proposal with Respect to Slice

BPA's final proposal for a Slice Rate includes the decisions made and stated in the May ROD previously filed, including any tables referred to in that ROD. The Slice Methodology as found in that ROD is modified (*see* Attachment to this Chapter 8) in accordance with the changes explained in this 2002 Final Supplemental ROD.

#### 8.2.1 Application of Load-Based Cost Recovery Adjustment Clause to Slice

In the May Proposal, BPA forecasted the need to increase or supplement the capability of the FCRPS, which was referred to as the Inventory Solution. Wholesale Power Rate Development Study, Appendix C, WP-02-FS-BPA-05, at C-3. The Inventory Solution also is referred to as "inventory augmentation" in BPA's 2002 Amended Power Rate Proposal (Amended Proposal) and Supplemental Proposal. Procter, *et al.*, WP-02-E-BPA-64, at 3. The May Proposal specified that the net costs associated with the Inventory Solution will be included in the Slice Revenue Requirement, and will become an obligation of the Slice purchaser. Mesa, *et al.*, WP-02-E-BPA-32, at 13. The Slice purchaser was responsible for a proportionate share of the net costs associated with the Inventory Solution. *Id.*

In the May Proposal, the net cost of the Inventory Solution was estimated and was not to be adjusted for actual expenses incurred for augmenting the system. *Id.* at 15. However, there was to be a one-time 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 would have been responsible for their proportionate share of those costs. *Id.* at 12. This one-time adjustment to the Inventory Solution has been replaced by the Load-Based Cost Recovery Adjustment Clause (LB CRAC) adjustment proposed by BPA in its Supplemental Proposal. Because this one-time adjustment to the Inventory Solution has been replaced by the LB CRAC adjustment, Table E in the General Rate Schedule Provisions is no longer applicable and will be removed. May ROD, Appendix 1: 2002 Wholesale Power Rate Schedules, WP-02-A-02, at 127. The Slice Methodology will also be changed to reflect changes associated with the application of the LB CRAC to the Slice product. The Inventory Solution True-Up Adjustment is no longer applicable. The Attachment to this Chapter 8 contains the red-lined changes to the Slice Methodology.

Refer to Chapter 4.3.1, Load-Based Cost Recovery Adjustment Clause, for the discussion of issues raised by parties and BPA's decisions with respect to the LB CRAC and its application to the Slice product.

### **8.2.2 Allocation to Slice of Proportionate Share of Monetary Benefits of Investor-Owned Utilities Settlement**

The Investor-Owned Utilities (IOU) Residential Exchange Program Settlements (REP Settlements) with regional IOUs provide benefits in the form of both power and cash. The monetary portion of the benefits is calculated, based on the difference between the Residential Load or Priority Firm Power-Exchange Subscription rate and BPA's rate case market price forecast. Originally, in the May Proposal, BPA adopted \$28.10/MWh as the five-year flat block price forecast for the monetary benefit component of REP Settlements. BPA is now proposing to calculate the financial aspect of the settlements using \$38/MWh for the monetary benefits component of the REP Settlement. 2002 Supplemental Power Rate Proposal Study, WP-02-E-BPA-67, at 1-10. In its May Proposal, BPA proposed that Slice purchasers be responsible for paying their proportionate share of these costs through the annual Slice true-up process. Mesa, *et al.*, WP-02-E-BPA-54, at 9. In its Amended Proposal, BPA proposed that the Slice portion of these increased costs be included as a separate line item in the monthly adjustment to the Slice bill, instead of including all of this difference in the annual true-up to actual costs. Procter, *et al.*, WP-02-E-BPA-64, at 14. BPA's Supplemental Proposal contains no change from the Amended Proposal with respect to including this difference in a monthly adjustment to the Slice bills. The monthly adjustment to Slice bills will equal \$65,043 per month per one-percent Slice. The table in Schedule PF-02 Section IV.G.2 of the 2002 Wholesale Power Rate Schedules will be changed to add this adjustment to the Slice bill. May ROD, Appendix 1: 2002 Wholesale Power Rate Schedules, WP-02-A-02, at 24.

### **8.2.3 Change to the Low Density Discount Application to Slice**

In the May Proposal, the Low Density Discount (LDD) benefit for Slice purchasers did not increase or decrease in accordance with increases or decreases in the PF rate for heavy load hour (HLH) and light load hour (LLH) billing determinants, due to the Targeted Adjustment Clause (TAC), CRAC, or the Dividend Distribution Clause (DDC). May ROD, Appendix 1, WP-02-A-02, at 103. This was because TAC, CRAC, and DDC did not apply to the Slice Rate.



In its Supplemental Proposal, BPA will apply the LB CRAC to the Slice Rate. Therefore, LDD benefits will increase in accordance with the increases or decreases in the PF rate for HLH and LLH billing determinants due to the LB CRAC.

**8.2.4        Changes to the Block/Slice Contract to Reflect Decisions in the Final Supplemental Record of Decision**

Section 18 in the Block/Slice Contract provides BPA the right to amend the contract to incorporate changes from decisions in the Final Supplemental Record of Decision (ROD). Refer to Chapter 4.3.1, Load-Based Cost Recovery Adjustment Clause, for the discussion of issues raised by parties and BPA's decisions with respect to amending the Block/Slice Contract to reflect decisions in the Final Supplemental ROD.

## ATTACHMENT TO CHAPTER 8

### 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. The monthly rate for the Slice product will be adjusted by the application of the Load-Based Cost Recovery Adjustment Clause (LB CRAC). -The LB CRAC is applicable for the FY 2002-2006 rate period, as defined in the 2002 Final Supplemental Proposal for Wholesale Power Rates.

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 **Financial-Based Cost Recovery Adjustment Clause (FB CRAC)**, **the Safety Net Cost Recovery Adjustment Clause (SN CRAC)**, **the Targeted Adjustment Clause (TAC)**, and **the Dividend Distribution Clause (DDC)**

Neither the Slice Rate nor the Slice True-up Adjustment Charge paid by Slice purchasers will be subject to the **FB CRAC**, **the SN CRAC**, **the TAC**, -or the DDC identified in the GRSPs or any successor thereto.

## 7. Applicability of the Load-Based CRAC

For the FY 2002- 2006 period, the LB CRAC will apply to the Slice Rate.

### 7.8. 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:

$$STUAC_M = (\del{ISTU_R} + ASTU_M)$$

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:~~

$$\text{ISTU}_R = (\text{CL}_R - \text{FL}_R) / \text{ISMW}_R * \text{NCIS}_R / 12$$

~~Where:~~

~~ISTU<sub>R</sub> is the Inventory Solution True-Up Adjustment for the rate period R.~~

~~CL<sub>R</sub> is the annual average Contracted Loads for the rate period R.~~

~~FL<sub>R</sub> is the annual average Forecasted Loads for the rate period R.~~

~~(CL<sub>R</sub> - FL<sub>R</sub>) cannot be a value less than zero.~~

~~ISMW<sub>R</sub> is the annual average MW associated with the Inventory Solution for the rate period R.~~

~~NCIS<sub>R</sub> is the annual average net cost of the Inventory Solution for the rate period R.~~

## **D. IOU Settlement Charge**

Each monthly Slice bill will include a line item to account for the proposed increment in the IOU cash settlement above the cash settlement amount included in the Slice Revenue Requirement in the May Proposal. The revenues from this incremental amount will not be included in any calculation of the LB CRAC.

The monthly adjustment per one-percent Slice will be:  
[Incremental amount of IOU Settlement costs in the Supplemental Rate Case  
ROD/12/100] = \$ per month per one-percent Slice.

## **TABLE 1**





Table 1 (continued)

		A	B	C	D	E	F
	<b>PBL Costs (\$000)</b>	2002	2003	2004	2005	2006	TOTAL
		2002-2006	2002	2003	2004	2005	2006
		Audited	Projected				
		Actuals					
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	<b>REVENUE REQUIREMENT CHECK</b>	<b>\$ 1,743,482</b>	<b>\$ 1,783,243</b>	<b>\$ 1,782,414</b>	<b>\$ 1,743,692</b>	<b>\$ 1,780,003</b>	<b>\$ 8,832,833</b>
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	<b>Non-COSA Table Subtotal</b>						<b>\$ 238,540</b>
95							
96	<b>Total PBL Revenue Requirement</b>						<b>\$ 9,071,373</b>
97							
98	<b>Revenue Credits (\$000)</b>						
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	<b>Total Revenue Credits</b>						<b>\$ 1,147,249</b>
112							
113	<b>Power Revenues Needed</b>						<b>\$ 7,924,124</b>
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	<b>Total Cost of Inventory Solution</b>	<b>\$ 441,522</b>	<b>\$ 461,485</b>	<b>\$ 419,294</b>	<b>\$ 459,294</b>	<b>\$ 447,036</b>	<b>\$ 2,228,632</b>
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	<b>Net Cost of Inventory Solution</b>	<b>\$ 114,287</b>	<b>\$ 134,250</b>	<b>\$ 92,059</b>	<b>\$ 132,060</b>	<b>\$ 119,801</b>	<b>\$ 592,457</b>
123							
124		(\$000)					
125	<b>Annual Slice Revenue Requirement</b>	<b>\$ 1,703,316</b>					
126	<b>Monthly Slice Revenue Requirement</b>	<b>\$ 141,943</b>			<b>Five Year Total</b>		<b>\$ 8,516,581</b>
127	<b>One Percent of Monthly Requirement</b>	<b>\$ 1,419.43</b>					
128							

## 9.0 PROCEDURAL MATTERS

### 9.1 Ex Parte Communications

#### Issue 1

*Whether BPA and the Joint Customer Group (JCG) repeatedly violated the rule against ex parte communications.*

#### Parties' Positions

The Direct Service Industrial Customers (DSIs) state in their initial brief that the Administrator's decision must be made on the basis of the record developed in the proceeding and not as the result of *ex parte* communications. DSI Brief, WP-02-B-DS/AL-02, at 18-19. The DSIs contend that the section 7(i) rate proceeding is subject to the *ex parte* limitations of not only BPA's own Rules of Procedure (1010.7) but also the Administrative Procedures Act (APA). The DSIs contend that BPA and its counsel "have engaged in knowing violations of Rule 1010.7 and the APA, by not merely declining to listen to proffered oral communications, but by initiating such improper communications. Instead of advising parties that BPA would 'not consider' *ex parte* communications BPA initiated the communications and agreed to alter BPA's Supplemental Proposal in the rate case based upon the communications." (emphasis in the original). *Id.* at 20-21.

In its brief on exceptions, the DSIs allege that there was an acknowledged failure on the part of BPA and the JCG to make incomplete and inconsistent responses to the DSI data requests. DSI Ex. Brief, WP-02-R-DS/AL-02, at 7. They go on to contend that the Hearing Officer's rulings on the *ex parte* issue denied them all reasonable factual inquiry into the full extent of the *ex parte* communications. *Id.*

Western Public Agencies Groups (WPAG) states that the record developed in cross-examination reveals a lack of evidence that the case involved improper attempts to influence the Administrator. WPAG Brief, WP-02-B-WA-01, at 10; WPAG Response WP-02-E-WA-05. WPAG states that the cross-examination testimony reveals that the decisions related to the Partial Stipulation and Settlement Agreement did not involve the Administrator, but rather, were decisions made by BPA staff independent of the Administrator. *Id.* at 10-11.

Northwest Requirement Utilities (NRU) states that DSI claims of wholesale violations of *ex parte* violations are not supported by the evidence. NRU Brief, WP-02-B-NI-02, at 14-15.

The JCG claim that the record demonstrates that the Partial Stipulation and Settlement Agreement was negotiated and developed through an open and public process. JCG Brief, WP-02-B-JCG-01, at 22. While there were contacts between representatives of the JCG and BPA staff during the course of the negotiations, almost all of these contacts were of the type expressly excepted under the *ex parte* rule. *Id.* at 23.

## **BPA Staff Position**

The Partial Stipulation and Settlement Agreement, which formed the basis for BPA's 2002 Supplemental Power Rate Proposal (Supplemental Proposal) provides the foundation for the DSI allegations. The Partial Stipulation and Settlement Agreement was negotiated during a series of publicly noticed meetings where the DSI representatives were generally present and participated in the discussions. BPA Response, WP-02-E-BPA-81. Throughout the course of nine noticed meetings before BPA filed its Supplemental Proposal, the substance of a BPA/JCG proposal was clarified, refined, and negotiated. *Id.* The meetings were well attended by representatives for every customer group, tribal interests, and public interest organizations. *Id.* At these meetings, materials for discussion were distributed to those in attendance and faxed to those participating by telephone. *Id.* As the discussions progressed, BPA and the sponsors of the JCG proposal were able to develop various aspects of the proposal in a manner that was acceptable both to the JCG and to BPA.<sup>1</sup> In those instances where agreement was reached, additional drafting was generally coordinated by the JCG representatives. *Id.* The proposals would occasionally be sent to BPA prior to an upcoming public meeting, but more often these written documents were presented to BPA in hard copy at the next public meeting with electronic copies of the documents forwarded later. *Id.*

The DSI allegations generally fall into one of two categories: (1) communications that occurred, but do not violate the rule; or (2) unsubstantiated assertions of secret meetings or discussions that never occurred. BPA provided a detailed allegation-by-allegation response to each of the matters raised by the DSIs in its Response to the DSI Motion. *Id.* There are several instances where the DSIs complain that BPA and the JCG knowingly discussed the substance of the Supplemental Proposal outside of the noticed meetings. DSI Motion, WP-02-E-DS/AL-06. However, the evidence shows that with each of these allegations the discussions fell within the scope of one of the exceptions to the rule. BPA Response, WP-02-E-BPA-81. With regard to the allegations of secret meetings or discussions, there is no evidence in the record substantiating the factual allegations made by the DSIs. *Id.* In particular, the contention that BPA attended meetings with the JCG is rebutted by the declarations of BPA staff. The balance of the allegations fall under one or more of the exceptions to the rule. *Id.*

## **Evaluation of Positions**

In the DSI Motion for an Evidentiary Hearing, the DSIs argue that BPA repeatedly violated the rule against *ex parte* communications and conclude that as a result of these repeated violations, the process has been tainted. DSI Motion, WP-02-E-DS/AL-06. In its brief on exceptions, the DSIs also allege that there was an acknowledged failure on the part of BPA and the JCG to make complete and consistent responses to the DSI data requests. DSI Ex. Brief, WP-02-R-DS/AL-02, at 7. They go on to contend that the Hearing Officer's rulings on the *ex parte* issue denied them all reasonable factual inquiry into the full extent of the *ex parte* communications. *Id.* The DSIs outline 10 specific instances of alleged *ex parte* communications in their Motion which they contend evidence wholesale violations of the rule. DSI Motion, WP-02-E-DS/AL-06. BPA's

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<sup>1</sup> The DSIs indicated from the outset that they found the proposal unacceptable. Public and tribal interest groups were fairly supportive of the effort to develop a proposal but noncommittal with respect to whether they could agree to support any proposal.

Response to the DSI Motion gives a detailed explanation of each of the specific allegations with an explanation why none of the allegations constitutes actual violations of the *ex parte* rule. BPA Response, WP-02-E-BPA-81.

Through a series of unfounded allegations and mischaracterizations of certain matters, the DSIs have attempted to weave an argument that there were wholesale violations of the rule against *ex parte* communications. DSI Motion, WP-02-E-DS/AL-06. The facts, however, do not support these assertions by the DSIs. BPA Response, WP-02-E-BPA-81.

The DSI specific allegations of *ex parte* violations either do not constitute a violation of rule or are allegations of events that never transpired. In BPA's, as well as WPAG's Responses to the DSI motion, the factual background to each of the allegations is provided. These explanations demonstrate that there is no factual basis to argue that the rule was violated. BPA Response, WP-02-E-BPA-81; WPAG Response WP-02-E-WA-05. The DSIs have provided little in the way of factual development to support these serious allegations. BPA and WPAG have provided a contextual background which demonstrates that each allegation falls under a specified exception to the rule. Even if the allegations did have some merit, the DSIs have not shown that the alleged contacts influenced the Administrator, nor were they denied the opportunity to rebut the substance of the Partial Stipulation and Settlement Agreement in their direct and rebuttal cases.

The DSIs claim that there was a failure on the part of BPA and the JCG to provide a full and complete response to the data request. DSI Ex. Brief, WP-02-R-DS/AL-02, at 7. The DSIs' concern appears to be based upon answers by BPA's policy panel during cross-examination that they were not approached about whether they had materials responsive to the DSI data request. *Id.* The evidence does not support the DSI contentions. While these witnesses may not have been approached, there is no indication from the record, despite cross-examination by DSI counsel on the issue, that they had any documents that would have been responsive to the request. Tr. 53. Rather, the testimony demonstrates that the witnesses in question did not receive any of the documents in question that form the basis for the DSI allegations of *ex parte* contacts. *Id.* Furthermore, despite BPA and the JCG producing hundreds of pages of documents responsive to the data request, the DSIs have failed to produce any that demonstrate the witnesses in question had any involvement in discussions with the JCG or were involved in drafting the Partial Stipulation and Settlement Agreement. Additionally, the testimony of Mr. Keep demonstrates that there was a concerted effort by BPA staff to negotiate the settlement with the JCG outside of the involvement of senior BPA management and the Administrator. Tr. at 105-107.

### **Decision**

*BPA and the JCG did not violate the rule against ex parte communications.*

### **Issue 2**

*Whether BPA and the Administrator violated the rule against ex parte communications by negotiating with the DSIs to buy down their load for the upcoming rate period.*

## **Parties' Positions**

Canby Utility Board argues that communications between BPA and the DSIs have violated the rule against *ex parte* communications and have “potentially jeopardized and tainted this entire proceeding.” Canby Brief, WP-02-B-CA-2, at 10. Canby points out ongoing discussions between BPA and the DSIs to amend the DSI contracts to buy down some or all of their Subscription load as the basis for this allegation. *Id.* Canby acknowledges that negotiations between BPA and the DSIs to amend their contracts are not rate case issues and do not violate the *ex parte* rule. *Id.* However, they contend that the amount paid by BPA to the DSIs to buy down the load is a rate case issue because it impacts the calculation of the Load-Based Cost Recovery Adjustment Clause (LB CRAC). *Id.* As a consequence, Canby requests that the communications related to the buydown of DSI load be halted. *Id.* at 11.

In its brief on exceptions, Canby modifies its argument somewhat by contending for the first time that the price paid by BPA to the DSIs and others to buy down load is a “rate” that must be set in this proceeding. Canby Ex. Brief, WP-02-R-CA-02 at 12. They believe that the “secret” negotiations with the DSIs related to the price paid for the buydown are taking place outside of the rate setting process in violation of the *ex parte* rules. *Id.* at 17. Canby contends that BPA must develop “curtailment rates” for the DSIs and other customers under the procedural requirements under the Northwest Power Act. *Id.*

## **BPA Staff Position**

BPA believes that the negotiations between BPA and the DSIs, as well as between BPA and its other customers, including Canby, to change terms and conditions of their Subscription Contracts are not discussions that violate the rule against *ex parte* communications. Furthermore, the price paid to BPA’s customer for the load reduction buydown is not a “rate.” Under BPA’s Rules of Procedure, there are exceptions to the *ex parte* rule. One of those exceptions is for communications that occur as part of the regular course of business. The discussions with the DSIs and others to reduce or alter the amount of load BPA is obligated to serve under Subscription contracts fall under this exception. *Rules of Procedures*, § 1010.7(b)(7). Neither the amount of load nor the amount BPA pays to buy back that load is a rate case issue. These are matters, which are part of BPA’s regular business dealings and are not communications that violates this *ex parte* rule.

## **Evaluation of Positions**

In its initial brief, Canby argued that if an activity in any way impacts the calculation of the LB CRAC, it is a rate case issue. Canby Brief, WP-02-B-CA-2, at 10. In particular, Canby argues that the negotiations related to the buy down of DSI load must stop because the reduction in load and the amount paid to buy down the load will impact the calculation of the LB CRAC. This argument is flawed because the mere fact that a reduction in load will impact the LB CRAC calculation does not make it a rate case issue and subject to the rule against *ex parte* communications.

Regarding Canby's new argument that the price being paid to the DSIs and others to buydown load is a rate and must be developed through a 7(i) proceeding, Canby Ex. Brief, WP-02-R-CA-02, at 17, Canby has provided no legal or evidentiary support of this interpretation of what constitutes a rate. Additionally, Canby did not attempt to raise this concern while the record was open, but instead waited until its brief on exceptions to address the issue. Even though Canby has waited until now to raise this question, the negotiations over the price paid to the DSIs and others to modify the delivery of power under their contracts is not a "rate" subject to the section 7(i) requirements. The term "rate" applies to the per unit charges related to sale or disposition of power, capacity, or transmission. In this case, BPA is not selling or disposing of power, capacity, or transmission, but rather is reducing its contractual load obligation to the particular customer through a modification to contracts. To that extent, the transactions are more akin to power purchase rather than a sale. Thus, these buydown costs will be reflected in the LB CRAC.

Canby uses a very broad interpretation of what constitutes an *ex parte* violation to argue that BPA must cease all communications with the DSIs and others related to the modifications to their Subscription load. If BPA were to adopt Canby's expansive interpretation of the *ex parte* rule, it would virtually stop all contract negotiations with any party during a rate case. Canby's interpretation of the *ex parte* rule would also prohibit BPA from taking any steps to address its augmentation need. Under Canby's interpretation of the rule, BPA would be prohibited from purchasing power on the open market since these transactions would have a similar impact on the calculation of the LB CRAC. While BPA must avoid communications that address the merits of issues in the rate proceeding, the rules against *ex parte* communications do not require BPA to isolate itself from all communication (outside of noticed meetings) with rate case parties. The *Rules of Procedures*, § 1010.7(b)(1)-(7) specifically provide exceptions that allow BPA to have contact with rate case parties during the course of the proceeding.

There are seven identified exceptions to the rule. Two of the exceptions apply to the negotiations with the DSIs that are the subject of Canby's complaint.

\*\*\*\*\*

(5) Relating to exchanges of data in the ordinary course of business, data required to be exchanged pursuant to contracts, or data which would be available pursuant to Freedom of Information Act requests.

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(7) Which relates to a topic that is only secondarily the object of a hearing, for which BPA is statutorily responsible under provisions other than Northwest Power Act section 7, or which is eventually decided other than through a section 7(i) hearing.

Rules of Procedure, 1010.7(b)(5) and (7).

Canby contends that these exceptions do not apply to the current negotiations. Canby contends that the first exception only applies to data exchanged in the ordinary course of business. Canby Ex. Brief, WP-02-R-CA-02, at 15. Canby states that “the issue here does not involve data (*i.e.*, loads or forecasts) but the development of new *rates* for the DSIs and others.” (*Emphasis in original*) *Id.* Canby also contends that the second exception does not apply because the “rates” (the amounts paid to the DSIs and others) are not secondary to this proceeding and as a result the exception does not apply. *Id.* at 16.

Canby’s rejection of the first exception is premised on the idea that only “data” exchanged in the ordinary course of business qualifies under this exception. This narrow interpretation would effectively prohibit BPA from negotiating contracts with its customers during the course of a rate case. In order to operate effectively during any rate case, BPA must be able to negotiate new contracts with its customers during the course of a rate proceeding, and it must be able to acquire power on the market to cover power obligations. It is not reasonable to read the word “data” in so narrowly so as to limit the exception to loads forecasts or other similar materials as Canby suggests. While contract negotiations are not specifically identified in the exceptions, they are considered to be an exception to the rule. *Central Lincoln People’s Utility District v. Johnson*, 735 F.2d 1101, 1119 (9<sup>th</sup> Circuit 1984).

Canby’s other argument that the exception under 1010.7(b)(7) does not apply is equally without merit. By claiming that the negotiations involve a “rate,” Canby contends that the discussions cannot be secondary to the rate case. Canby Ex. Brief, WP-02-R-CA-02, at 15. These load reduction discussions with customers do not involve the development of rates or rate design issues in this proceeding. Canby simply stating, without evidence, that the discussions are rate issues does not make them so. As noted in Issue 1, these negotiations are not related to the establishment of a rate.

Canby’s complaint also involves the contention that the current negotiations with the DSIs to amend their contracts will impact the calculation of the LB CRAC. While it is true that BPA’s efforts to buydown customer load are intended to reduce the level of augmentation purchases, such an effort does not influence or pre-decide any given rate proposal or design. In today’s market, the buydown of the DSI and other contracted loads are not issues in the rate case, but are one aspect of BPA’s augmentation mitigation strategy. These discussions are part of the ordinary course of BPA’s dealings with the DSIs and have only a secondary impact on the rate proceeding.

### **Decision**

*BPA negotiations with the DSIs and with BPA’s other customers regarding amendments to Subscription contracts to buy down load do not violate the rate case rule against ex parte communications.*

### **Issue 3**

*Whether the Administrator should appoint a special administrative law judge (ALJ) to hold an evidentiary hearing into the alleged BPA/DSI ex parte communications.*



## **Parties' Positions**

Canby argues in its initial brief and in its brief on exceptions that there were a number of documented *ex parte* communications between BPA and the DSIs that create the basis for the appointment of a special ALJ to conduct a hearing to look into the impact of these contacts on this proceeding. Canby Brief, WP-02-B-CA-02, at 14; Canby Ex. Brief, WP-02-R-CA-02, at 5 and 22. While Canby notes the cross-examination of BPA and non-DSI parties produced an adequate record on the allegations of *ex parte* communications between BPA and the JCG, Canby contends that there remain a number of open questions regarding BPA and DSI communications. Canby Brief, WP-02-B-CA-02, at 14. Specifically, Canby points to a breakfast meeting between the Administrator and DSI representatives in February 2001 and a series of meetings between Mr. Norman and DSI representatives to discuss the DSI Subscription Contracts. *Id.* at 15-16. Canby believes that further inquiry is needed to determine the impact of these discussion on the rate proceeding.

In the Canby brief on exceptions, Canby contends that it did not waive its right to raise *ex parte* issues. Canby Ex. Brief, WP-02-R-CA-02, at 20. It believes that its the decision not to cross-examine any witnesses regarding the alleged *ex parte* contacts with the DSIs was not an error because it had already developed a record on the issue through its motions. *Id.* Canby states that cross-examining BPA witnesses would not accomplish anything, because the witnesses had “limited information about the matters Canby wished to probe.” *Id.* at 21-22.

Canby also reiterates its argument regarding the need for the appointment of an ALJ to conduct an evidentiary hearing. Canby believes that the Hearing Officer erred in failing to disqualify herself from ruling on Canby’s Motion for an Evidentiary Hearing. Canby Ex. Brief, WP-02-R-CA-02, at 5. Canby argues that because the Hearing Officer had a provision in her contract with BPA that stated, in part, that a “confidential, fiduciary relationship exists with respect to the subject matter of the services provided,” she no longer could serve as an impartial decision maker. *Id.* at 5-6. Canby believes this contractual provision gives BPA the right to communicate privately with the Hearing Officer about the subject matter of the case, thereby undermining the decisionmaking process. *Id.* at 7.

## **BPA Staff Position**

At cross-examination, the Hearing Officer properly ruled on the motions related to *ex parte* violations that were brought by Canby and the DSIs as well as Canby’s related motion to disqualify the Hearing Officer. In particular, the Hearing Officer denied Canby’s request to disqualify her and have an ALJ appointed to conduct an inquiry into the alleged *ex parte* violations that occurred between BPA and representatives of the DSIs. Tr. at 5-15. The Hearing Officer correctly noted that: Canby’s interpretation of the contract with BPA was flawed. *Id.* As the Hearing Officer noted, she “does not have authority to order a separate hearing to appoint another hearing officer to order depositions, issue subpoenas, or impose sanctions.” Tr. at 13. The Hearing Officer recognized she is not an ALJ, but rather her obligation and the scope of her authority extended only to the development of a full and complete record. Tr. at 6. To that end, the Hearing Officer allowed the motions and responses on the *ex parte* issues to be put into evidence and allowed parties to conduct cross-examination on the issue. Tr. at 6 and 96.

Additionally, to the extent that the confidentiality provision in the Hearing Officer's contract has any applicability, it runs to her obligation to conduct a hearing in compliance with section 7(i) of the Northwest Power Act. Finally, the Hearing Officer gave parties an opportunity to develop a record on the subject. Canby failed to avail itself of the opportunity provided by the Hearing Officer. In particular, Canby declined to cross-examine Mr. Keep or other panels on the alleged contacts and did not raise any objection when asked if additional cross-examination was needed on the *ex parte* issues. Tr. at 96 and 258.

### **Evaluation of Positions**

Canby argues that the Administrator should appoint a special ALJ to conduct a hearing into the alleged *ex parte* violations that occurred between BPA and representatives of the DSIs. Canby Brief, WP-02-B-CA-02, at 14. Canby believes that, while there is a sufficient record developed regarding alleged *ex parte* contacts between BPA and representatives of the JCG, additional information is necessary to complete the record on the contacts with the DSIs. *Id.* It contends, however, that there was no purpose in cross-examining BPA witnesses about these contacts with the DSIs, because they had "limited information about the matters Canby wished to probe." Canby Ex. Brief, WP-02-R-CA-02, at 22. Canby also combines this argument with a separate contention that the Hearing Officer erred in failing to recuse herself from ruling on Canby's Motion for an Evidentiary Hearing. Canby Ex. Brief WP-02-R-CA-02, at 5-11.

Canby believes that the confidentiality provision in the Hearing Officer's contract with BPA undermines the "constitutional right to an impartial decision-maker in administrative proceedings." *Id.* at 7. Canby's concern with regard to the Hearing Officer is misplaced. As the Hearing Officer states in her ruling on Canby's motion no fiduciary relationship exists between herself and BPA. Tr. at 8-9. She went on to state:

Now, if a fiduciary interest can even be said to exist, it is merely that I provide a service which is mandated by statute and for which Bonneville is obligated to pay. The day that Bonneville attempts to oversee the service I provide in any way or to control the process to its own advantage is the day I would recuse myself.

Tr. at 8-9.

The Hearing Officer's duties are dictated by the section 7(i) rate directives. *See* 16 U.S.C. § 839e(i)(2). As such, her obligation runs, not to some fiduciary relationship between herself and BPA or its Office of General Counsel, but rather to her statutory duty to develop a full and complete record from which the Administrator can make a decision. Furthermore, even if Canby were correct in its reading of the contract, the Hearing Officer explained in her ruling that she had never been privy to any confidential information, nor was she consultant to BPA's Office of General Counsel, nor did she communicate with BPA except through formal pleadings, nor did she discuss the merits of the case with BPA counsel. *Id.* at 7-8.

Ultimately however, whether the Hearing Officer erred in failing to recuse herself is irrelevant because the more fundamental question is whether an ALJ should have been appointed to conduct an evidentiary hearing into the alleged *ex parte* contacts with the DSIs. While Canby argues that a special ALJ is necessary to develop the record, Canby fails to explain why the

procedures established by the Hearing Officer were adequate to develop the record on the *ex parte* contacts with the JCG, but were not sufficient to develop the record with the DSIs. *Id.*

During cross-examination the Hearing Officer denied Canby's motion for recusal of the Hearing Officer and the appointment of a special ALJ. *Id.* at 10. At the hearing it was determined that parties would be allowed to conduct a special cross-examination of Mr. Keep on *ex parte* issues, and after this cross-examination, the Hearing Officer would try and determine if parties felt there was any basis for further cross-examination on the subject. *Id.* at 12 and 96. Canby did not participate in the cross-examination of Mr. Keep or any other witness. When asked if further cross-examination was necessary, Canby did not ask for additional or alternative measures to supplement the record nor did it object to the ones employed. *Id.* at 258. As the excerpt of the transcript notes, during cross-examination Canby specifically stated that they had no other witness they wanted to call to develop the *ex parte* issue after the cross-examination of Mr. Keep.

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MR. BURGER: When we left last night, Mr. Murphy was going to consider over the evening how he wanted to continue to pursue the *ex parte* issue. I thought now that we're between panels and we're close to lunch, we might try and address that issue if it can be addressed quickly.

HEARING OFFICER EDWARDS: Mr. Murphy?

MR. MURPHY: Well, as I previously indicated, we've taken exception to some of the rulings of the Hearing Examiner, and we've had an opportunity to ask questions of Mr. Keep. I wouldn't propose at this time, given the rulings that have occurred, I'm not proposing to call any other witnesses on that particular issue.

MR. BURGER: We can't hear you.

MR. MURPHY: I may have some questions of remaining panels when they are up for cross-examination, although I kind of doubt it.

HEARING OFFICER EDWARDS: Okay.

MR. BURGER: One other thing. Canby Utility was (257) also somewhat involved in that issue, as well. I'd like to know, too, for the record, whether they are of the same mind, I guess?

HEARING OFFICER EDWARDS: Is there someone here from Canby Utility this morning?

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HEARING OFFICER EDWARDS: Yes, okay. Mr. Seligman, we're here discussing what was proposed yesterday as testimony on *ex parte*. Mr. Murphy has now said he has no other witnesses he intends to call. How does Canby stand on this issue?

MR. SELIGMAN: I have no other witnesses I'd like to call on this issue.

HEARING OFFICER EDWARDS: Thank you.

MR. SELIGMAN: Thank you.

Canby elected not to cross-examine any BPA or other witness regarding the alleged *ex parte* contacts. Canby now claims that BPA and other party witnesses had limited knowledge of the

subjects that Canby wished to probe. Canby Ex. Brief, WP-02-R-CA-02 at 22. However, Canby made no effort to confirm this fact during cross-examination. These witnesses may or may not have had the information that would have confirmed or refuted the alleged problems. By failing to cross-examine witnesses to determine this fact, Canby cannot now complain that the procedures were inadequate or that the witnesses had no information, when no effort was made to confirm this fact. It cannot, as it has in this instance, make no effort to develop a record and then complain that the record or procedure is inadequate.

Canby asserts that BPA witnesses on the panels are “technical experts rather than managers or executives who decide final rates” making the need to cross-examine them unnecessary given the issues it has raised. *Id.* This allegation by Canby displays a level of confusion regarding both the make-up of BPA’s panels and the rate setting process. Under BPA’s rate directives, the Administrator, not any of the managers or executives, decides final rates. 16 U.S.C. § 839e(i)(4). Canby’s assertion that there were no executives and managers on panels is not supported by the record. For example, Allen Burns, Syd Berwager, and Byron Keep are executives and managers at BPA in addition to being witnesses on panels. WP-02-Q-BPA-08; WP-02-Q-BPA-03; WP-02-Q-BPA-34.

Additionally, the Hearing Officer does not have the authority to appoint a special ALJ to conduct an evidentiary hearing. BPA’s Hearing Officer is appointed by the BPA Administrator pursuant to section 7(i) of the Northwest Power Act. BPA has published its procedural rules, and no such power to order an evidentiary hearing is granted to the Hearing Officer. *Procedures Governing Bonneville Power Administration Rate Hearings, 51 Fed. Reg. 7611 (1986)*. The Hearing Officer’s defined role is “to develop a full and complete record and to receive public comment in the form of written and oral presentation of views, data, questions, and argument related to such proposed rates.” 16 U.S.C. § 839e(i)(2). During the hearings, the Hearing Officer is required to provide participants with an adequate opportunity “to offer refutation or rebuttal of any material submitted,” 16 U.S.C. § 839e(i)(2)(A), and to “allow a reasonable opportunity for cross examination . . . in order to develop information and material relevant to any such proposed rate” (16 U.S.C. § 838(i)(2)(B)). Decisions on the merits of all substantive issues are specifically reserved to the Administrator. 16 U.S.C. § 839e(i)(5) (quoted above).

### **Decision**

*The Administrator need not appoint a special ALJ to develop a record regarding the alleged DSI ex parte communications with BPA because every opportunity to develop a record was offered during this rate proceeding.*

### **Issue 4**

*Whether BPA violated the rule against ex parte communications by negotiating the Partial Stipulation and Settlement Agreement with rate case parties.*

## **Parties' Positions**

The DSIs contend that there were numerous and intentional violations of the rule against *ex parte* communications by BPA staff and its counsel during the course of the negotiations and development of BPA's Supplemental Proposal. DSI Brief, WP-02-B-DS/AL-02, at 20. The DSIs believe that BPA not only listened to oral communications but also initiated such improper contacts and agreed as a consequence to make the results of these communications part of BPA's Supplemental Proposal. *Id.* at 20-21. The DSIs contend that there are dozens of oral and written contacts that violated the rule against *ex parte* communications, and of these, BPA only complied with the disclosure once and that effort failed to fully comply with the rules. *Id.* at 21-22. Additionally, the DSIs contend that BPA also violated the procedural requirements by failing to place memoranda memorializing noticed meetings in the agency *ex parte* file. *Id.* at 21.

WPAG states that the DSI allegations of *ex parte* violations are an attempt to derail the process rather than a legitimate concern about procedural defects. WPAG Brief, WP-02-B-WA-01, at 10. WPAG states that the record shows that the Partial Stipulation and Settlement Agreement, which formed the basis for BPA's Supplemental Proposal, was negotiated in publicly noticed meetings, which were attended by the DSIs. *Id.* Any contacts between BPA and rate case parties outside of these noticed meetings were for the purpose of gathering an understanding of the proposal. *Id.* These contacts are expressly permitted under the rules. *See* section 1010.7(b). WPAG also notes that the DSIs' cross-examination of BPA witnesses did not establish that the efforts to negotiate a settlement improperly involved the Administrator. *Id.* at 20-21.

## **BPA Staff Position**

BPA conducted the discussions regarding the Partial Stipulation and Settlement Agreement in conformance with the rule against *ex parte* communications. BPA Response, WP-02-E-BPA-81. Throughout the course of seven noticed meetings that took place before BPA filed its Supplemental Proposal, the substance of a BPA staff/JCG proposal was clarified, refined and negotiated. The meetings were well attended by representatives for every customer group (including the DSIs), tribal interests, and public interest organizations. *Id.* At these meetings, materials for discussion were distributed to those in attendance and faxed to those participating by telephone. As the discussions progressed, BPA staff and the sponsors of the JCG proposal were able to develop various aspects of the proposal in a manner that was acceptable both to the JCG and to BPA staff. In those instances where agreement was reached, the JCG representatives generally coordinated additional drafting among rate case parties. *Id.* The proposals would occasionally be sent to BPA staff prior to an upcoming public meeting, but more often these written documents were presented to BPA in hard copy at the next public meeting with electronic copies of the documents forwarded later. *Id.*

With one exception, which was memorialized by a memorandum to the *ex parte* file, there were no instances when BPA and the JCG had *ex parte* discussions involving any substantive matter related to the proposal. All other substantive discussions occurred during the noticed meetings. BPA and the customers made every effort to provide all parties with the latest version of the Partial Stipulation and Settlement Agreement for discussion at the next public meeting. The draft documents developed through the public meetings ultimately formed the basis for BPA's

Supplemental Proposal, which reflected many, but not all, of the features originally proposed by the JCG.

Thus, the seven noticed meetings held before BPA filed its Supplemental Proposal protected the integrity of the section 7(i) process. At the same time the noticed meetings allowed BPA to work with customers, and other interested groups, toward the end of finding a regional solution to a cost recovery problem whose consequences could be quite severe.

The evidence relied upon by the DSIs to support their claim of *ex parte* violations is not in alignment with the facts. BPA's response and the accompanying declarations demonstrate that allegations of improper *ex parte* contacts are not supported by the facts. *Id.*

### **Evaluation of Positions**

The DSIs believe that there were wholesale violations of the rule against *ex parte* communications during the proceeding. In support of these allegations, the DSIs point to a series of written communications that were produced by the parties pursuant to data requests. DSI Brief, WP-02-B-DS/AL-02, at 20. From these documents the DSIs have attempted to weave a pattern of behavior that is allegedly in willful disregard of the rule against *ex parte* communications. The facts, however, do not support the DSI allegations.

As the responses and declarations of both BPA and WPAG demonstrate, the alleged pattern of *ex parte* violations did not exist. BPA Response, WP-02-E-BPA-81; WPAG Response, WP-02-E-WA-05. To the extent contact cited by the DSIs between BPA and representatives of the JCG actually happened, each contact fell under one of the enumerated exceptions to the rule. *Rules of Procedure*, 1010.7(b)(1)-(7).

The evidence shows that substantive discussions related to the Partial Stipulation and Settlement Agreement occurred during the seven noticed meetings, except for the one occasion. BPA Response, WP-02-E-BPA-81, at 13; WPAG Response, WP-02-E-WA-05. That one occasion when the *ex parte* contact occurred and violated the rule, BPA wrote up the discussion and placed it in the *ex parte* file. BPA Response, WP-02-E-BPA-81, at 13. Furthermore, the substance of the discussion involved a limited issue related to manner in which Slice purchasers tried up for augmentation costs. *Id.* Thus, the manner in which this matter was resolved was disclosed to the DSIs at a noticed meeting five days later. Tr. 126. The DSIs' argument relies upon a number of occasions where drafts of documents were shared prior to or after meetings. In each of these instances, as the declarations in BPA's and WPAG's responses show, the documents merely reflected understanding reached at a prior meeting. *Id.* WPAG Response, WP-02-E-WA-05. Furthermore, the testimony of Mr. Keep during cross-examination by the DSIs stated that when documents were exchanged prior to or after noticed meetings, BPA always responded to the substantive proposals at noticed meetings. Tr. at 115. Contrary to the inferences of the DSIs, these documents did not reflect substantive changes, but rather, merely memorialized the agreement reached between the parties at noticed meetings.<sup>2</sup> This type of

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<sup>2</sup> One of the primary examples relied upon by the DSIs in their Motion is a draft of the Partial Stipulation and Settlement Agreement exchanged between BPA and representatives of the JCG. The DSIs claim that the document showed extensive revision marks that in their opinion supported their claim that BPA and the JCG were negotiating

dissemination of duplicative material, which was distributed at a publicly noticed meeting, provides no basis for *ex parte* concerns. Also, the communication appears to be more grounded in procedure than in the substance of the issues.

The DSIs' other claims of secret meetings between BPA and the JCG are not supported by the facts. As BPA's Response notes, the alleged meetings never occurred. BPA Response, WP-02-E-BPA-81, at 14.

The final type of allegation relates generally to discussion between BPA technical staff and other rate case parties. DSI Motion, WP-02-E-DS/AL-06. The purpose of the discussions was unrelated to the "merits" of any proposal. Instead, the discussions were designed to gain a better understanding of certain aspects of the proposal so it could then be modeled and evaluated. BPA Response, WP-02-E-BPA-81, at 10. There is a specific exception to the *ex parte* rule for these types of clarification questions. *See Rules of Procedure*, 1010.7(b)(1)-(7).<sup>3</sup> In fact, these requests for information and the responses to them exemplify the type of on-going dialogue that occurs between technical staff on both sides during every rate case.

The DSIs also contend that BPA was obligated under the Rules of Procedure to file a memorandum in the *ex parte* file after each of the noticed meetings. DSI Brief, WP-02-B-DS/AL-02, at 21. While BPA is obligated under the Rules of Procedure to file a memorandum outlining the substance of the meeting, the obligation did not extend to the noticed meetings in this case. The Rules of Procedure make a distinction between generally noticed meetings and noticed meetings between BPA and individual customers and customer groups. If BPA is holding a generally noticed meeting for all rate case parties, there is no obligation to draft and file the memorandum referenced by the DSIs. However, as the rule notes, if the meeting is with "individual customers" or "customer groups" then BPA is obligated to file the memorandum. The reason for this distinction is to insure when there is a meeting limited to a select group of customers, that the other customer groups be afforded the opportunity to know and understand the substance of the discussions. Because all of the noticed meetings were general in nature, there was no obligation to file a memorandum.

### **Decision**

*The BPA staff negotiations with rate case parties that resulted in the Partial Stipulation and Settlement Agreement did not violate the ex parte rule.*

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through an exchange of electronic documents. However, as the BPA Response notes, the electronic tags on the revisions demonstrate that the changes were made during a noticed meeting where DSI attorneys attended and participated in the editing of the document. BPA Response, WP-02-E-BPA-81.

<sup>3</sup> The discussion referenced in the DSI motion is very similar to inquiries by the DSI technical consultant, Mr. Bliven, just days before. As Mr. Bliven's e-mails demonstrate, he requested information that would assist in his understanding of the modeling of certain ToolKit runs.

## 9.2 Hearing Officer Rulings

### Issue 1

*Whether the Hearing Officer's rulings on ex parte issues raised by the DSIs during this proceeding should be reversed.*

### Parties' Positions

The DSIs contend that the Hearing Officer's failure to permit the DSIs to demonstrate the scope, nature, and effect of improper *ex parte* communications should be remedied. DSI Brief, WP-02-B-DS/AL-02, at 23. The DSIs argue that the APA provides the Hearing Officer broad authority to allow factual development regarding *ex parte* communications. *Id.* The DSIs believe that Sections 556 and 557 of the APA apply to these proceedings and that it is within the Hearing Officer's authority to order an evidentiary hearing as contemplated under the APA. *Id.* at 25. The DSIs also contend that the Hearing Officer's ruling that limited cross-examination on *ex parte* issues to BPA and the parties designated witnesses was an error. *Id.* at 26. The DSIs assert that limiting cross-examination in this fashion "foreclosed any examination into the adequacy of the disclosures of *ex parte* communications." *Id.* at 26.

WPAG contends that the Hearing Officer did not err in her rulings on the DSI request for an evidentiary hearing. WPAG Brief, WP-02-B-WA-01, at 9. The Hearing Officer's obligation is to develop a full and complete record on the issues and she acted within the scope of her authority when she denied the DSI request for the evidentiary hearing.<sup>4</sup> *Id.* The Hearing Officer developed a full record by moving into evidence the motions and responses on this issue as well as the accompanying declarations and exhibits. *Id.* at 9-10. She also allowed cross-examination of witnesses with first hand knowledge of events. *Id.* The evidentiary record developed not only fails to substantiate the conspiracy theory advanced by the DSIs, but also evidences a settlement negotiated in publicly noticed meetings. *Id.* at 10. The record further demonstrates that the decisions regarding the settlement were made by BPA rate staff and did not involve the Administrator. *Id.* at 10-11.

In their brief on exceptions, the DSIs contend that the Hearing Officer denied them the opportunity to demonstrate how the alleged *ex parte* communications influenced the Administrator's decision. DSI Ex. Brief, WP-02-R-DS/AL-02, at 8. The DSIs contend that it is not credible to believe that the Administrator makes decisions in the rate case isolated from staff who were involved in the *ex parte* communications. *Id.* at 9. In support of this argument the DSIs cite a discussion between the Hearing Officer and DSI counsel during which they claim she foreclosed any questioning of BPA witnesses about their interactions with the Administrator. *Id.*

In the DSI's brief on exceptions, the DSIs also contend that the decision during cross-examination not to extend the *ex parte* questioning was not a waiver of the issue. The DSIs believe the decision not to cross-examine additional witnesses was the result of a prior

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<sup>4</sup> Although WPAG's arguments address only the DSI motion, given the similarity of issues raised by Canby, WPAG's arguments have been interpreted as applying to Canby's issues as well.



decision by the Hearing Officer, that “foreclosed any reasonable factual inquiry in the full extent of *ex parte* communications.” DSI Ex. Brief, WP-02-R-DS/AL-02, at 7.

### **BPA Staff Position**

BPA staff position is that the Hearing Officer rulings on *ex parte* issues raised by the DSIs do not constitute reversible error. The DSIs sought relief in the form of an evidentiary hearing that was beyond the scope of her authority. BPA Response, WP-02-E-BPA-81, at 19. The Hearing Officer properly denied the DSIs motion, but consistent with her obligation to develop a full and complete record, the Hearing Officer allowed all rate case parties to explore in cross-examination the extent to which any *ex parte* contacts occurred. Tr. at 14. The Hearing Officer also noted that parties, including the DSIs, had already listed the potential *ex parte* witnesses in their briefs. Tr. at 16-17. The decision by the Hearing Officer to allow cross-examination permitted a record to be developed on the issue. The record the DSIs developed shows that there were no violations of the *ex parte* rule and that the DSIs did not establish that the entire process has been tainted.

The Hearing Officer did not foreclose any questioning by the DSIs about the interaction between the Administrator and staff, but rather, properly limited the questioning to matters of which the witnesses had direct knowledge. Tr. at 50.

### **Evaluation of Positions**

The DSI Motion requested the Hearing Officer order an evidentiary hearing and grant relief based on provisions of the APA, specifically 5 U.S.C. § 557(d)(1)(D). As authority for this request, the DSIs rely upon *Central Lincoln People’s Utility District v. Johnson*, 735 F.2d 1101, 1119 (9<sup>th</sup> Circuit 1984). The DSIs interpretation of this case expands it far beyond its intended scope. The DSIs argue that *Central Lincoln* provides the BPA Hearing Officer with broad powers to order evidentiary hearings, issue subpoenas, determine the merits of substantive issues, and order relief consistent with her findings on such issues.

However, section 9(e)(2) of the Northwest Power Act makes it clear that the record for final rate determinations is to be compiled in accordance with the Northwest Power Act and that the final rate determinations are to be supported by substantial evidence. Section 9(e)(2) concludes by stating: “Nothing in this section shall be construed to require a hearing pursuant to APA section 554, 556, or 557 of title 5.” 16 U.S.C. § 839f(e)(2). The Report of the House Committee on Interstate and Foreign Commerce supports this exemption from the APA requirements: “The adjudication provisions of 5 U.S.C. 554 and 557 do not apply to hearings under this bill.” H.R. Rept. No. 96-976 (Part I), 96<sup>th</sup> Congress. 2d Session (May 15, 1980), at 71. Thus, the specific language of the statute and its legislative history confirm that Congress’ intent was that the Northwest Power Act, not the APA, would govern hearings conducted by BPA pursuant to statute, including a section 7(i) rate proceeding.

Additionally, BPA’s Hearing Officer is appointed by the BPA Administrator pursuant to section 7(i) of the Northwest Power Act. The Hearing Officer’s defined role is “to develop a full and complete record and to receive public comment in the form of written and oral presentation of views, data, questions, and argument related to such proposed rates.” 16 U.S.C. § 839e(i)(2).

During the hearing, the Hearing Officer is required to provide participants with an adequate opportunity “to offer refutation or rebuttal of any material submitted,” 16 U.S.C. § 839e(i)(2)(A), and to “allow a reasonable opportunity for cross examination . . . in order to develop information and material relevant to any such proposed rate” (16 U.S.C. § 838(i)(2)(B)). Decisions on the merits of all substantive issues are specifically reserved to the Administrator. 16 U.S.C. § 839e(i)(5).

With respect to the DSIs’ request for an evidentiary hearing, the Hearing Officer is not empowered to offer such relief pursuant to the procedural rules. *See* 51 Fed. Reg. 7611(1986). The power to order a hearing is not inherent in the appointment of a Hearing Officer. Instead, the existence of such powers must be “subject to published rules of the agency and within its powers.” 5 U.S.C. § 556(c). BPA has published its procedural rules and no such powers are granted to the Hearing Officer.

The Hearing Officer is charged with the duty to develop a full and complete record for the Administrator’s consideration. To the extent that the Hearing Officer determines that the record should develop evidence regarding possible *ex parte* violations, it is within the Hearing Officer’s discretion to develop that evidence through the tools and powers granted by section 7(i) of the Northwest Power Act.

In her ruling, the Hearing Officer granted the DSIs and Canby the opportunity to cross-examine witnesses on the subject to develop a record. At Oral Argument, the Hearing Officer also allowed the record to be supplemented with additional evidence. Oral Tr. at 7-8. The DSIs were given an opportunity to develop a record on this issue. However, as noted below, the DSIs elected not to continue to explore the subject beyond the limited cross-examination they conducted.

MR. BURGER: When we left last night, Mr. Murphy was going to consider over the evening how he wanted to continue to pursue the *ex parte* issue. I thought now that we’re between panels and we’re close to lunch, we might try and address that issue if it can be addressed quickly.

HEARING OFFICER EDWARDS: Mr. Murphy?

MR. MURPHY: Well, as I previously indicated, we’ve taken exception to some of the rulings of the Hearing Examiner, and we’ve had an opportunity to ask questions of Mr. Keep. I wouldn’t propose at this time, given the rulings that have occurred, I’m not proposing to call any other witnesses on that particular issue.

MR. BURGER: We can’t hear you.

MR. MURPHY: I may have some questions of remaining panels when they are up for cross-examination, although I kind of doubt it.

Tr. 256.

The DSIs contend in their brief on exceptions that the Hearing Officer foreclosed any questioning about the extent to which the alleged *ex parte* communications influenced the Administrator’s decision. DSI Ex. Brief, WP-02-R-DS/AL-02, at 8. The DSIs cite a discussion between DSI counsel and the Hearing Officer during cross-examination in support of the alleged

improper ruling. However, an examination of the discussion reveals that her ruling did not conflict with the scope of cross-examination the DSIs wished to engage.

MR. MURPHY: Your Honor, 7(i) requires that the Administrator make a decision based on the record developed in the 7(i) process. If, in fact, the Administrator makes the decision based upon information provided to the Administrator by staff other than what is in the 7(i) process, I believe that that does not comport with the requirements of 7(i). That's what I want to make my record on. I want to be very clear what I'm trying to do here. And if you're going to prevent me from making (51) the record on that, that certainly you have to rule on the motions before you. But that's what I'm trying to get at is information communicated to the decision-maker that may not have been on the record at all, and what does that information then influence what the decision-maker does.

HEARING OFFICER EDWARDS: The witnesses are only going to know about those things which they, themselves, were actually involved in and have actual knowledge of. You may ask them if they know about a specific instance, and if they do not, you may not question them on it any further. You can't expect these witnesses to know what everybody in the agency is doing with everybody else at any given moment in time, and I think that's reaching too far. You may ask them as to things that are within their actual knowledge and participation, and that's all.

MR. MURPHY: I'll confine myself to that, which I intended to, anyway.  
Tr. at 50.

Rather than supporting their contentions, the above discussion on the record reveals that, at worst, there was a misunderstanding between Mr. Murphy and the Hearing Officer, but in the end, Mr. Murphy acknowledged her ruling did not conflict with or limit the scope of his cross-examination.

### **Decision**

*The Hearing Officer's rulings on the ex parte issues are consistent with her authority under section 7(i) and will not be reversed.*

### **Issue 2**

*Whether the Hearing Officer's ruling on participant comments submitted by Canby should be reversed.*

### **Parties' Positions**

In its brief on exceptions, Canby contends that the Hearing Officer erred when she denied Canby's Motion to Supplement the Record (WP-02-M-134) and refused to allow documents submitted by Canby into the participant comment file. Canby Ex. Brief, WP-02-R-CA-02, at 23. Canby delivered 1,009 petitions that it collected from its customers under a cover letter to Acting Administrator Stephen Wright. *Id.* at 24. These materials were not made part of the participant

comment file, and Canby filed its motion to introduce the materials on the record. Canby believes the Hearing Officer erred when she denied Canby's motion because the materials were not *ex parte* communications and should have been admitted under section 7(i)(3) of the Northwest Power Act. *Id.* at 28.

### **BPA Staff Position**

BPA believes that the Hearing Officer did not err in her ruling. The materials submitted by Canby as participant comments were both *ex parte* violations as well as improper participation by a party in the participant comment process. Canby does not deny that the materials were submitted to BPA under a cover letter to BPA's Acting Administrator. As such they were *ex parte* communications. Canby also does not deny or even address in its brief on exceptions, the fact that the materials in question were submitted by Canby as participant comments. Rate case parties such as Canby are not allowed to participate in the participant comment portion of the rate case. *See* Rules of Procedure, 1010.5.

### **Evaluation of Positions**

Canby believes that the Hearing Officer erred when she denied Canby's Motion to Supplement the Record. Canby Ex. Brief, WP-02-R-CA-02, at 23. In particular, it believes that the materials in question were properly submitted to BPA's Public Involvement Office in compliance with the requirements set out in the Federal Register Notice, 65 Fed. Reg. ¶ 75272 (1999). Canby Ex. Brief, WP-02-R-CA-02, at 23. Along with the 1,009 petitions, Canby submitted a cover letter addressed to BPA's Acting Administrator Stephen Wright. *Id.* at 24. Canby claims that the materials were improperly excluded from the participant comment file as *ex parte* communications because they were submitted in compliance with the requirements in the Federal Register Notice. *Id.* at 23. In addition, Canby alleges that the documents cannot be considered *ex parte* communications even though the comments were sent under a cover letter to the Administrator, because the comments were submitted as part of a noticed public process. *Id.* at 25. Similarly, Canby believes that it has the right, under section 7(i)(3) of the Northwest Power Act, to submit additional comments separate and apart from what it submits in the rate case. *See* 16 U.S.C. § 839e(i)(3). *Id.* at 23.

The Hearings Officer did not err in her rulings on this matter. While the record appears to support the BPA staff's contention that these Canby submissions were *ex parte* communications, that fact is secondary to the undisputed record evidence that these petitions were the result of a coordinated effort by Canby to take part in the participant comment portion of the rate case. Canby does not deny or refute that it gathered the petitions in question through an organized effort and it, not the customers, submitted them to BPA for inclusion in the participant comment file. The *Rules of Procedure* do not allow any party to take part in participant phase of the rate case. *Rules of Procedure*, 1010.5. To allow Canby, or any other party, to become involved in the participant phase of this rate case, effectively dilutes the public's ability to participate in the proceeding.

Canby now contends that petitions were also submitted to BPA under section 7(i)(3) of the Northwest Power Act. 16 U.S.C. § 839e(i)(3). Canby Ex. Brief, WP-02-R-CA, at 23. It is not

clear whether Canby is arguing that the petitions were submitted under section 7(i)(3) when originally presented to BPA in February 2001 or that they should be treated as such now. Regardless of Canby's intent, the petitions cannot be considered for submission under section 7(i)(3). Canby acknowledges that originally, the petitions were clearly intended to be included in the participant comment file. Canby Ex. Brief, WP-02-R-CA-02, at 24. It is clear that Canby did not intend for the materials to be treated as materials submitted under section 7(i)(3) in February 2001. To the extent that Canby now wants the materials to be treated as submittals under section 7(i)(3), Canby has not complied with the requirements of the statute. The statute specifically provides materials must be submitted "prior to, or before the close of, the hearing..." 16 U.S.C. § 839e(i)(3). At best it can be argued that Canby did not make this request until it filed its Motion to Supplement the Record, well after the close of the hearing. Given Canby's failure to pursue this matter, before the close of the hearing, it cannot complain that the Hearing Officer erred in her ruling.<sup>5</sup>

Canby fails to acknowledge the fact that the Hearing Officer did allow a representative sample of the materials submitted into the participant comment file. *See* WP-02-0-36. Given that there were only a few different types of petitions, the use of a representative sample insured that the message contained in the petitions was acknowledged and addressed, but did not allow Canby to violate the spirit and intent of the participant comment phase of this proceeding.

### **Decision**

*The Hearing Officer's order on the participant comments submitted by Canby will stand.*

## **9.3 Determinations of Administrator Based on the Record**

### **Issue 1**

*Whether execution of the Partial Stipulation and Settlement Agreement by BPA staff bound the Administrator to adopt the Supplemental Proposal in this Record of Decision, thereby making this rate proceeding a sham.*

### **Parties' Positions**

The DSIs contend that the Partial Stipulation and Settlement Agreement represents an agreement to "resolve" the issues in the rate case. DSI Brief, WP-02-B-DS/AL-02, at 32. The DSIs argue that the Partial Stipulation and Settlement Agreement, in conjunction with a BPA witness stating that he had "the authority to act for Bonneville," make this entire proceeding a sham. *Id.* Given the apparent authority of the BPA staff to resolve issues and bind the agency, the DSIs contend that the Administrator is not making an independent decision but rather is bound to implement the Partial Stipulation and Settlement Agreement in the ROD. *Id.* at 32-33. As a consequence, the DSIs argue that this proceeding is a sham. *Id.* at 32.

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<sup>5</sup> Canby states in its brief on exceptions that it learned that the petitions were removed to the *ex parte* file on April 5, 2001. Canby Ex. Brief, WP-02-R-CA-02, at 24. The hearing was closed after the end of cross-examination on April 13, 2001. Canby had ample opportunity to ask the Hearing Officer to have the petitions admitted to the record under section 7(i)(3) prior to the close of the hearing.

The DSIs argue that there is no distinction between BPA staff and the Administrator with regard to the settlement in this case. DSI Ex. Brief, WP-02-R-DS/AL-02, at 13. The DSIs allege that because BPA staff is bound by the terms of the settlement agreement, BPA staff could only support the Settlement Agreement in advising the Administrator when he made the decisions in this ROD. *Id.* The DSIs argue that a disinterested party would find that, under these circumstances, the Administrator had prejudged the outcome. *Id.*

### **BPA Staff Position**

It is BPA's position that the existence of a Partial Stipulation and Settlement Agreement as negotiated between BPA staff and the rate case parties does not make this proceeding a sham. BPA went to great lengths to ensure that the Administrator would not be bound by the Partial Stipulation and Settlement. Tr. at 120-123. The Administrator had the discretion to reject the settlement between BPA staff and rate case parties if he decided to elect that course of action. Tr. at 122-123. The settlement in this proceeding was between BPA staff and the JCG and did not represent a binding obligation for the Administrator to follow. Tr. at 123.

Furthermore, the Partial Stipulation and Settlement Agreement has specific provisions dealing with the possibility of the Administrator when he made decisions that are different from the provisions negotiated between BPA staff and the JCG. Burns and Berwager, WP-02-E-BPA-70, Attachment A, at 5. These provisions contradict the DSI position that the Administrator is bound by the Partial Stipulation and Settlement.

### **Evaluation of Positions**

The DSIs argue that the Partial Stipulation and Settlement Agreement represents a binding commitment that requires the Administrator to adopt the proposal in the ROD. DSI Brief, WP-02-B-DS/AL-02, at 32. In support of this, the DSIs point to selected provisions of the Agreement and isolated statements from cross-examination to support this argument. DSI Motion, WP-02-E-DS/AL-06. The DSIs also contend that BPA staff was bound by the Partial Stipulation and Settlement Agreement and thus effectively denied the Administrator objective assistance in crafting this ROD. DSI Ex. Brief, WP-02-R-DS/AL-02, at 13. This fact they contend leads to the conclusion that the case had a predetermined outcome. *Id.* Contrary to the DSI allegations, the Partial Stipulation and Settlement Agreement does not represent an agreement that binds the Administrator to adopt the substance of the proposals contained in the agreement. Burns and Berwager, WP-02-E-BPA-70, Attachment A, at 5. The evidence in the record clearly demonstrates that the Partial Stipulation and Settlement Agreement only represents an agreement on the part of BPA staff to develop a Supplemental Proposal consistent with the terms of the agreement. *Id.* at 5. The Partial Stipulation and Settlement Agreement is not a binding commitment on the part of the Administrator to follow the terms in the ROD, but rather it has specific provisions that contemplate the possibility that the Administrator may adopt an alternative proposal. Burns and Berwager, WP-02-E-BPA-70, Attachment A, at 5.

The DSIs contention that the Partial Stipulation and Settlement Agreement set in place a course of events that practically foreclosed the Administrator from adopting an alternative proposal is without merit. Underlying the DSI argument is a belief that the execution of the Partial

Stipulation and Settlement Agreement put matters on to a set of “predestined groves” that precluded the Administrator from getting objective counsel from his staff due to their obligation to support the agreement. DSI Ex. Brief, WP-02-R-DS/AL-02, at 13. This conclusion is not supported by the facts, and adopting such a limiting standard would render the entire rate setting process moot. Under the DSIs argument, BPA could never settle any issue during a rate case since it would apparently lead down the “predestined grooves” that they believe occurred in this case. According to the DSIs, settling any issue and making that settlement part of BPA’s rate proposal would commit the Administrator to adopting the settlement in the ROD. Under this logic, it could also be said that any aspect of BPA’s rate proposals would lead to these “predestined grooves” committing the Administrator to the BPA proposal. The faulty element in the DSI logic is the premise that BPA staff are apparently unable to render objective counsel to the Administrator due to staff’s commitment to a particular proposal.<sup>6</sup> Under this logic, because staff presumably supports the adoption of BPA’s rate proposal, they would not support alternative proposals when advising the Administrator. Adopting this DSI logic would render the entire rate setting process moot.

Furthermore, the DSIs have not established that the Administrator did not get objective assistance when crafting this ROD. While BPA’s staff was committed to the Supplemental Proposal, there is no evidence to support the leap the DSIs make to binding the Administrator. In support of their argument, the DSI cite the cross-examination of Mr. Keep. The DSIs contend that when Mr. Keep testified that he “had authority to act for Bonneville” and as a consequence bound the agency and the Administrator. DSIs’ Brief, WP-02-B-DS/AL-02, at 32 and Tr. 107. The DSIs take this statement out of context and give it a meaning beyond any reasonable interpretation. As Mr. Keep’s testimony clearly demonstrates, his authority was limited and the signing of the Partial Stipulation and Settlement Agreement was a staff agreement with parties that did not bind the Administrator in any way.

Q. (Mr. Murphy) And during this series of negotiations, did you get guidance from Mr. Allen Burns or other management in BPA, other than what you've described as the negotiating team as to how you should proceed?

A. (Mr. Keep) No.

Q. (Mr. Murphy) So that the negotiating team was totally empowered to work this matter out with the joint customers?

A. (Mr. Keep) Yes.

Q. (Mr. Murphy) After you worked out what you thought was an acceptable proposal through the negotiating team, did you get -- did you check with your superiors in Bonneville on the form that the GRSPs revisions would take in your testimony, in the supplemental proposal?

A. (Mr. Keep) The form that the GRSPs would take was, once again, my responsibility, so I'm not really sure I understand your question. But the way -- once we reached an agreement and we felt that agreement needed to be developed in detail in the GRSPs or to what we call GRSPs level of detail, that it was my responsibility to ensure that that detail got developed and to make the decisions that it was in sufficient detail for our needs.

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<sup>6</sup> Under the Partial Stipulation and Settlement Agreement there is no procedural or financial consequence resulting from BPA staff, or any other party’s, failure to adopt or support the proposal outlined in the agreement.

Q. (Mr. Murphy) I want to try to break it up into two pieces. You got to the point where the parties' proposal, you had worked out some discussions on that, and there was then a subsequent need to get it down to the GRSPs detail. Did you go at any point -- between those two steps, did you go to your superiors and say this is what we think we've got. Is it a go? Shall we move forward? Or was it at that point where you still were operating on the assumption that you were empowered to make those judgments?

A. (Mr. Keep) I was still empowered to make those judgments.

Q. (Mr. Murphy) So you didn't go to your superiors to say this is what we've got now, and I'm going to get it down to GRSPs detail?

A. (Mr. Keep) No. I briefed them on the settlement, on what we had in the settlement. But I didn't ask them, really it didn't occur to me to ask them whether they liked it or not, whether they thought it was good, bad or indifferent. When we -- I assumed they meant it when they said it was my responsibility, and I was carrying it out.

Q. (Mr. Murphy) And who were these superiors that you briefed?

A. (Mr. Keep) I believe it was -- well, I know for sure Allen Burns was there. And I believe it was Paul Norman and Jim Curtis and Randy Roach as the other key individuals. There were other people at the briefing, but those were the four that I was concerned with.

Q. (Mr. Murphy) Based on your work with those individuals, would you have expected them to, if they had serious concerns about whether the negotiating team had come out at that point, they would have so indicated to you?

A. (Mr. Keep) No. And here's the reason why. Back in September when we talked about settling, the issues of whether this could be -- what would happen if it was not a complete, hundred percent settlement and how would we deal with that. And in the period that we were discussing it, if it was in a partial settlement what could Bonneville do. And it was decided that the staff could propose a settlement, and the staff could reach a settlement, but we needed to take extra care to make sure that the Administrator still had his freedom to choose, based on the record, whatever he felt was best. And so I expected that once this became a partial settlement that whether they were happy with the settlement or not, because of the way -- because of the discussions we had earlier, that it was still to be a staff settlement and I was responsible for putting together the staff settlement. And then based on the record, the decision would be made. But by -- by the Administrator. So when I briefed people on what the settlement was, I treated it as a briefing and explained it and I did not expect anybody to say yeah or nay about whether he thought it was good, bad or indifferent.

Q. (Mr. Murphy) Did you also explain at that time the status of the line-up of the parties that were either on board or not on board with respect to that settlement?

A. (Mr. Keep) Yes, as best as I could.

Tr. at 120-123.

The agreement only required BPA staff to file a Supplemental Proposal consistent with the proposal negotiated between BPA staff and the JCG. Burns and Berwager, WP-02-E-BPA-70,



Attachment A, at 2. The agreement also does not have any consequence if BPA staff chose to file a Supplemental Proposal inconsistent with the agreement. *Id.*

The DSIs' argument that both Mr. Keep's signature on the agreement and the representation that he had the authority to execute and perform under the agreement, bound the Administrator is inconsistent with Mr. Keep's testimony. Clearly, he was only committing BPA staff to file a Supplemental Proposal consistent with the terms of the Partial Stipulation and Settlement Agreement. He testified that he kept his superiors informed about the status of the negotiations, but noted that they did not instruct him about how he should proceed. Tr. at 123. He also explained that while he was free to negotiate an agreement, his authority only went to developing the BPA staff/JCG proposal and did not bind the Administrator or agency in general. *Id.* While the DSIs attempt to argue that the Partial Stipulation and Settlement Agreement bound the Administrator, the facts do not support such a finding.

### **Decision**

*The execution of the Partial Stipulation and Settlement Agreement by BPA staff did not bind the Administrator to adopt the Supplemental Proposal in this Record of Decision.*

### **Issue 2**

*Whether public statements by the Administrator encouraging the DSIs to reduce their load on BPA for the first two years of the rate period is evidence of a predetermination by the Administrator of the issues in this proceeding.*

### **Parties' Positions**

The DSIs contend that by publicly requesting the DSIs to shut down for two years to help avoid a large rate increase for all of BPA's customers, before the final decision has been made in this proceeding, the Administrator has indirectly decided to reject the DSI tiered rate proposal and adopt the Supplemental Proposal. DSI Brief, WP-02-B-DS/AL-02, at 34; DSI Ex. Brief, WP-02-R-DS/AL-02, at 14. The DSIs also point to a web-posted BPA memorandum that stated that with a 250 percent rate increase it was unlikely that the DSIs would be able to operate profitably. *Id.* at 34. The DSIs argue that this statement is further evidence of the Administrator's adoption of the Supplemental Proposal. *Id.* at 35. The DSIs seek to have the Administrator disqualify himself from issuing a Final ROD on this matter to avoid denying the DSIs their due process rights. *Id.* at 35-36.

The DSIs contend that the question is whether the Administrator has prejudged the merits of this case given the alleged *ex parte* communications and statements by the Administrator regarding reduction of BPA's load. DSI Ex. Brief, WP-02-R-DS/AL-02, at 11. The DSIs believe that the standards embodied in the Northwest Power Act require that the decision be based upon the record developed by the Hearing Officer citing 16 U.S.C. § 839e(i)(5). *Id.* The DSIs argue that the statements by the Administrator and the "extra record conduct" only lead to a conclusion that a disinterested observer would find that the Administrator had prejudged this case. (*Citing to Cinderella Career and Finishing School, Inc. v. FTC*, 425 F.2d 583, 590 (D.C. Cir. 1970)). *Id.*

## **BPA Staff Position**

The Administrator has an open mind with respect to his decisions in this rate proceeding. The Administrator made this clear during oral argument when he stated:

I would like for everyone to know that the fact that I may have thoughts and opinions on something at any particular time, based on what I then know, should not be taken as indicating that I have a closed mind on any issue.... I look forward to listening to all of the arguments today. They'll be of great assistance to me as I continue to review the case before making any final decisions, all of which will be reflected in the final ROD.

Oral Tr. at 12-13. Clearly, the Administrator's statements reflect an open mind and show that he has not predetermined the issues in this rate case. In addition, the facts do not support the DSI conclusion that the Administrator has prejudged the merits of the issues in this case. The decision to pursue a policy of reducing BPA's Subscription load obligations does not evidence predetermination of any issue in this case. The reduction of load is not inconsistent with either of the two base rate designs at issue in this rate case. Furthermore, there is no evidence that the Partial Stipulation and Settlement Agreement, or the negotiations leading up to the settlement, resulted in the prejudgment of the case, as the DSIs allege.

## **Evaluation of Positions**

The DSIs argue that the Administrator has predetermined the outcome of this rate case. DSI, WP-02-B-DS/AL-02, at 24. In support of this proposition they point to some public statements the Administrator made regarding the need to reduce BPA's load obligations. The DSIs contend that the public statements are inconsistent with the adoption of the DSI tiered rate proposal. *Id.* The DSIs also contend that a memorandum posted on the BPA web site that discusses the impact of a 250 percent rate increase on DSI operations, and the general allegations of *ex parte* contacts with BPA staff during the negotiation of the Partial Stipulation and Settlement Agreement confirm, that the Administrator has predetermined the outcome of the rate case.<sup>7</sup> They believe that given these events, a disinterested observer would conclude that the Administrator had prejudged the issues in this case. *Cinderella Career and Finishing School, Inc. v. FTC*, 425 F.2d 583, 590 (D.C. Cir. 1970).

The limited facts relied upon by the DSIs do not support this conclusion. As noted above, the DSIs point to three different matters, on the record, in support of their argument. The first is a statement by the Administrator regarding BPA's need to reduce its overall load obligation to keep the overall rate impact down. DSI Brief, WP-02-B-DS/AL-02 at 34. This is the only evidence the DSIs discuss that can actually be attributed to the Administrator. All of the other

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<sup>7</sup> In their brief on exceptions the DSIs also reference a statement by BPA's public information officer to a Spokane newspaper as evidence of the Administrator's closed mind. The Hearing Officer denied a DSI motion to have this material added to the record. The DSIs brief on exceptions states in a footnote that the decision by the Hearing Officer to deny the DSI motion to supplement the record was wrong and should be reversed. DSI Ex. Brief, WP-02-R-DS/AL-02, at 15, note 6. The DSIs have presented no factual or legal support for reversal of the ruling. As a consequence it is not possible to respond to the merits of the argument. However, upon review of the order, the legal and factual determinations contained in the order are reasonable and accurate, respectively. WP-02-O-39.

examples cited by the DSIs are not statements or actions by the Administrator. The conclusions the DSIs draw from these statements by the Administrator do not support the conclusion that he prejudged the merits of any issue in this rate case.

One of the two factors that lead to the reopening of the 2002 rate case was the additional demand placed upon BPA that was not forecasted in the May Proposal. To the extent that BPA pursues a policy that attempts to reduce that demand on BPA, it is a matter outside the scope of this rate case. Although never explained, the DSIs imply that pursuing this policy objective is somehow inconsistent with or unnecessary under their tiered rate proposal. The facts simply do not support this conclusion. Reducing the demand on BPA does not preclude the adoption of tiered rates nor is it inconsistent with such a rate design. Under either of the two basic rate proposals, reducing demand on BPA has a positive impact on the overall rate levels for all customer classes either by lowering the rate adjustment or allowing a greater percentage of a customer's load to be served at the base rate. Finally, the statement relied upon by the DSIs was only one part of a four part strategy to deal with the problems faced by BPA and its customers. When read in context of the other points made by the Administrator regarding conservation and other actions, it is not reasonable to conclude that the Administrator was precluding the adoption of tiered rates.

The balance of the allegations by the DSIs are matters which can only be indirectly attributed to the Administrator. The paper posted on BPA's web site is the product of BPA staff and was not intended to be the position of the Administrator in the rate case. Furthermore, the fact that parties could potentially face a 250 percent rate increase under the BPA staff proposal is a factual assertion, not a predecision on the part of the Administrator. The DSI contention, that the Administrator's failure to mention that the DSIs could operate at some level under their proposal evidences his predetermination, is not supported by the facts.

Additionally, the DSIs do not establish any link between to the Administrator and the alleged *ex parte* communications. As the cross-examination of Mr. Keep demonstrated, he negotiated the Partial Stipulation and Settlement Agreement on behalf of BPA's staff. Tr. at 106-107. He testified that he conducted the negotiations with the intent that the Administrator would not be bound or unfairly influenced by the Partial Stipulation and Settlement Agreement. Tr. at 120-123. At the conclusion of the negotiations, it was intended that the Administrator would be free to adopt an alternative approach if he deemed it appropriate. Tr. at 122-123. The allegations by the DSIs that the supposed *ex parte* communications resulted in a prejudgment on the part of the Administrator is based purely on speculation. The DSIs can point to no particular piece of evidence or testimony to support this serious allegation.

BPA staff note that the Administrator stated during oral argument he did not have a closed mind on the major issues and that the facts the DSIs point to in support of their argument do not necessarily reflect a predetermination on the part of the Administrator. The statement by the Administrator demonstrates that he had an open mind about all of the issues in this rate case.

The DSIs correctly point out that the Northwest Power Act requires the decision by the Administrator be based upon the record compiled in the case. DSI Ex. Brief, WP-02-R-DS/AL-02, at 11. But they go on to claim that if the Administrator has pre-existing views, those too must be submitted as evidence. *Id.* In support of this requirement, the DSIs cite

16 U.S.C. § 839f(e)(2). This statutory provision deals with judicial review of final actions and has nothing to do with the manner in which the Administrator make decisions in a rate case. The statute says that judicial review “of such final actions shall be limited to the administrative record...” 16 U.S.C. § 839f(e)(2). The statute makes no reference to any obligation on the part of the Administrator to put his “pre-existing views” into evidence. Furthermore, no part of BPA’s rate directives provides for such a requirement.

Prejudgment does not result merely because the Administrator takes a position, in public, on policy issues. While the DSIs claim that the statements by BPA staff and the Administrator evidence a closed mind on the issues in this rate case, the case law does not support such an interpretation. A previously announced position on policy, does not disqualify him as a decisionmaker. *Skelly Oil Co. v. FPC*, 375 F.2d 6, 18 (10<sup>th</sup> Cir. 1967) (“In our opinion no basis for disqualification arises from the fact or assumption that a member of an administrative agency enters a proceeding with advance views on important economic matters in issue.”) In *FTC v. Cement Institute*, 333 U.S. 683 (1948), before the administrative proceeding was initiated, the Commission had issued an opinion that the particular system of pricing and selling cement that was at issue in the case constituted an illegal restraint of trade. When the Commission subsequently issued a cease and desist order against the use of this pricing and selling system, the *Cement Institute* alleged that the Commission had pre-decided the issue. In finding for the Commission, the Court found that “that fact that the Commission had entertained such views as the result of its prior *ex parte* investigations did not necessarily mean that the minds of its members were irrevocably closed on the subject.” *Id.* at 701. The important point here was that the court did not require the Commission to demonstrate an open mind on the matter, but rather that their collective minds were not “irrevocably closed.” *Id.*

The Administrator clearly stated during oral argument that, while he may have made some prior statements on the merits of buying down DSI load, he had not made up his mind on the rate issues before him and any final rate decisions would be reflected in the ROD. The DSIs have not shown sufficient evidence that the Administrator has a closed mind and cannot be an impartial decisionmaker.

### **Decision**

*The Administrator’s actions during the course of this proceeding do not evidence an irrevocably closed mind or predetermination of the critical rate issues in this proceeding.*

### **Issue 3**

*Whether the “rate lock” provisions in Canby’s contract preclude the application of the LB and SN CRACs.*

### **Parties Position**

Canby contends that the “rate lock” provisions in its Subscription Contract preclude the application of the LB and SN CRACs. Canby Brief, WP-02-B-CA-02, at 3; Canby Ex. Brief,

WP-02-R-CA-02 at 29. In support of this proposition it points to Section 12(b) of the Subscription Contract which provides the following:

BPA may adjust rates for the Contracted Power set forth in the applicable power rate schedule during the term of this Agreement pursuant to the Cost Recovery Adjustment Clause in the 2002 GRSPs.

*Id.*

Canby contends its five-year contract does not contain the language “or successor GRSPs” as contained in the 10-year Subscription contracts; therefore, BPA is precluded from applying the LB and SN CRACs to Canby’s contract. *Id.* Canby believes that application of the LB and SN CRAC would require BPA to revise the GRSPs during the five-year rate period after the GRSPs have been approved by FERC. *Id.* at 30.

Canby further contends that the setting of the LB and SN CRAC levels during the rate period violates the specific rate lock provisions of its contract and requests that the parameters of these CRACs be adjusted so that they are clearly spelled out. *Id.*

### **BPA Staff Position**

The contractual provisions Canby relies upon do not support its argument. The provisions contained in the 2002 GRSPs do not violate the Subscription Contract provision because when the LB and SN CRACs are adjusted during the rate period, the adjustment will be done “pursuant to the Cost Recovery Adjustment Clause in the 2002 GRSPs” as provided for under Canby’s contract.

### **Evaluation of Positions**

Canby contends that its Subscription Contract precludes the application of the LB and SN CRACs. Canby Brief, WP-02-B-CA-02, at 3; Canby Ex. Brief, WP-02-R-CA-02, at 29. Because its five-year contract does not contain the phrase for “successor GRSPs,” as is in the ten-year Subscription Contracts, Canby believes that BPA cannot apply the periodic adjustments of the LB CRAC or trigger the SN CRAC during the 2002-2006 rate period. *Id.* In its brief on exceptions, Canby states: “BPA cannot revise the GRSPs for the 5-year rate period after they have been approved by FERC.” *Id.* at 30. Canby further argues “BPA can—and will—change rates as a result of this proceeding.” *Id.*

Canby’s argument is premised on the faulty assumption that by adjusting the LB CRAC or triggering the SN CRAC during the rate period, BPA is resetting rates in violation of this contract provision. The presence or absence of the “successor GRSPs” language is not relevant. Once submitted and approved by FERC, BPA will have only one set of GRSPs for the upcoming rate period.

Once submitted and approved by FERC, the GRSPs will contain the previously described LB, FB, and SN CRACs. *See* Chapter 4. The CRACs allow BPA to make adjustments to the base rate levels to address specific problems. When each of the CRACs is triggered, the adjustments

to base rates from the application of the CRACs will be the result of implementing the provisions in the 2002 GRSPs. Canby's argument appears to be based upon a faulty understanding of how the proposed GRSPs will work. The resulting adjustments from the application of the various CRACs will all occur pursuant to the provisions contained in the 2002 GRSPs and not, as Canby contends, result from changes to the 2002 GRSPs themselves.

### **Decision**

*LB and SN CRACs do not violate the "rate lock" provisions in the five-year Subscription contracts.*

## **9.4 Environmental Analysis**

This proceeding is a continuation of the WP-02 Rate Proceeding. This phase of the proceeding is being conducted for the discrete purpose of resolving a cost recovery problem brought about by market price trends and load placement changes occurring since the record was closed in the first phase of the proceeding. Burns and Berwager, WP-02-E-BPA-62, at 3. BPA's proposed amendments deal with this cost recovery problem by modifying certain risk mitigation tools contained in the GRSPs, which apply to the base rates. 65 Fed. Reg. 75272 at 75274 (2000). BPA views this approach as a reliable and prudent means of assuring cost recovery while maintaining the basic underpinnings of BPA's Subscription Strategy for marketing power in the coming rate period. *Id.*

In the May ROD, the Administrator determined that the BPA's Final 2002 Power Rate Proposal was 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). May ROD, WP-02-A-02, at 18-51. Consistent with the Business Plan ROD, the Administrator reviewed the BP FEIS to determine whether the actions embodied in proposing the 2002 power rates were adequately covered within the scope of the BP FEIS. *Id.* The Administrator took into account the fact that the BP FEIS evaluated the six business policy direction alternatives and the choice of the Market-Driven alternative. *Id.* at 18-52. As noted in the May ROD, BPA noted that the conditions impacting the agency's successful performance may change over time. *Id.* at 18-53. As stated in the May ROD, the Market-Driven alternative contains preparatory mitigation measures (response strategies) to respond to changing market conditions and allow the agency to balance costs and revenues. *Id.*

In light of the unprecedented price spikes during the 2000 summer months, BPA determined that its cost-based rates for 2002-2006 would be far more attractive to prospective customers than market alternatives. BPA conducted a public process by which input from the region was sought. *See infra* 1.3.1. After regional input, BPA elected to pursue modifications to the CRAC; make adjustments to the Slice methodology; adjust the forecasts used in the Residential Exchange Program Settlements; and address the Subscription contracts signed in the summer of 2000 in order to deal with the issues facing BPA. *Id.* 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.

In adopting the proposed modifications reflected in this ROD, there has been a second review of the BP EIS to determine whether these modifications are also consistent with the Market-Driven alternative. After reviewing the proposed modification in light of the BP EIS, it is clear that the decisions contained in this ROD are consistent with the Market-Driven alternative. As noted in the May ROD:

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.

May ROD, WP-02-A-02, at 18-53. The proposed modifications allow BPA to ensure cost recovery while at the same time allowing it to meet its financial, public service, and environmental obligations. The adjustable LB CRAC provides BPA the additional advantage of being able also to “adapt to changing market conditions.” *Id.*

## **9.5            Participant Comments**

### **9.5.1        Introduction**

This section summarizes and evaluates the comments of participants received by BPA after the publication of the FRN in December 2000 for the 2002 wholesale power rate proceeding. 65 Fed. Reg. 75272 (2000). Participants are persons and organizations who comment on BPA’s rate proposal by attending BPA’s field hearing, or through correspondence or phone calls, but do not take part in the formal rate case hearing. Comments of participants are part of the official record of the rate proceeding and are considered when the Administrator makes his decisions set forth in this Final Supplemental ROD.

The participants’ portion of the Official Record consists of a transcript of BPA’s field hearing held January 22, 2001, in Portland, Oregon. At the field hearing, two individuals presented comments. BPA also received approximately 105 pieces of correspondence and documented telephone calls related to the rate filing during the public comment period which officially ended February 14, 2001. Over several thousand additional pieces of correspondence were received after the conclusion of the official public comment period through April 2001. Comments received after the deadline are not reflected in the tallies below.

BPA reviewed the participants’ portion of the record and identified the concerns expressed by the participants to be addressed in this chapter of the Supplemental ROD. Comments on technical areas addressed by the parties are evaluated in the foregoing Supplemental ROD chapters that address those topics. Following is a tally and summary of the testimony provided at the field hearing and the letters and phone calls that BPA received both during and after the comment period, along with BPA’s responses to 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.

## 9.5.2 Evaluation of Participant Comments

The following summary indicates the total responses for each issue. Many letters contained more than one comment. A total of 253 comments from letters and 6 comments from the field hearing were analyzed.

### Issue: Rate Case Process

<b>Rate Case Process</b>	<b>Letters Comments</b>	<b>Field Hearing Comments</b>
a. Consider other options	4	1
b. Fix deregulation; against deregulation	1	1
c. Take a slow look at the problem		1
d. Tell the truth about the rate increase	1	
e. Let people know what the problem is; thank you for information about the problem	2	
f. Thank you for sending power to California	2	

### Discussion

Several commenters asked BPA to consider options other than the proposal announced in BPA's FRN for dealing with difficult market conditions, such as average increases over time rather than front loading rate increases. Some believe that the deregulation of electricity in California is causing the rate increases, and that the deregulation process in California should be changed to address the Northwest's problems. Likewise, they believe the Northwest should move slowly before embracing deregulation, and that BPA should not sell power to California. Several commenters requested clearer information about the effects on end-users. Two California commenters used the rate process to thank BPA for assisting California during the energy shortages during the Summer of 2000.

BPA was encouraged by the commenters to look at other ways of resolving cash deficiencies, both in the short-term and the long-term, such as incremental short-term increases to deal with the volatile market. One way that BPA's proposal has been adjusted from the 2002 Amended Power Rate Proposal (Amended Proposal) is to adjust the LB CRAC every six months, rather than setting a fixed number for the entire rate period. This adjustment will give the agency more flexibility to deal with short-term deficiencies. This does not yield an "average" increase, as one commenter suggested, but does allow the rates to adjust downward when the price and supply outlook improve over time.

As the commenters correctly note, much of the west coast price and supply situation is not within BPA's control. However, BPA is actively working to reduce the size of the load that will be placed on it in an effort to reduce the costs that must be passed on to the purchasing utilities. BPA is actively involved in public information campaigns to educate consumers about energy conservation, and supports the governors in their call for reduced consumption. In addition,



BPA is working with its utility, irrigation, and industrial customers to find ways to reduce the amount of electricity they will need from BPA.

**Issue: Equity and Fairness**

<b>Equity and Fairness</b>	<b>Letters Comments</b>	<b>Field Hearing Comments</b>
a. Equity among customer classes	1	
b. People who use the most should pay the most	2	1
c. People who have low incomes, senior citizens, and others cannot pay higher rates	16	1
d. Form letter with these issues: keep rates fair; do not subsidize aluminum companies	151	

**Discussion**

Commenters expressed considerable concern over the impact of increased rates on various classes of customers and citizens. These commenters do not want to see small users subsidize large users, and believe that each user should pay its fair share. They suggested schemes that might impose a higher rate for those who use more power. One of BPA’s customer utilities initiated a letter-writing campaign after the close of the official participant comment period, with signatures of their consumers who are concerned about sales to the DSIs.

BPA recognizes that the impacts of rate increases at the wholesale level will be felt at the retail level as well, depending on how the retail utility chooses to pass along the increase. BPA also hopes that rate increases will be short in duration, and that the proposed LB CRAC, which can be adjusted every six months, will be significantly lower in the later years of the five-year rate period when the volatile west coast energy market is expected to moderate. Unfortunately, given that the summer of 2001 is a dry year, BPA has been forced to buy power in the market to serve its customers, making the situation worse for the beginning of the new rate period than it would be under more normal water conditions. The current expectation is that within two years, supplies and loads will be better matched, and the need for high prices will have moderated. In the meantime, BPA and the utilities are committed to helping with conservation programs to assist individuals and businesses to reduce their energy consumption and thus reduce their power bills. For example, consumers will be encouraged to contact their retail utility to participate in programs such as a compact fluorescent bulb subsidy.

BPA’s current proposal works toward equity, because all customer classes will be subject to the same kind of adjustments to their rates. However, to the extent that each customer reduces its load on BPA, all costs will be reduced. BPA has asked the DSIs to consider temporarily shutting down their operations to ease the power situation in the Northwest. Each company is assessing whether it can accept a buyout offer.

**Issue: Resources**

<b>Resources</b>	<b>Letters Comments</b>	<b>Field Hearing Comments</b>
a. Increase generating capacity		1
b. Encourage renewable resources	4	
c. Give public access to generator designs	1	
d. Use pumped storage (Banks Lake)	2	
e. Resume construction of nuclear plants	1	

**Discussion**

Commenters suggest a wide variety of additional resources that BPA should consider to ease the future supply/demand imbalance: solar, geothermal, wind, pumped storage, ocean wave generation, and resumption of construction of Washington Nuclear Plants 1 and 3.

BPA is aware that additional generation will help ease the problem of serving loads, and reduce the amount of power that it must buy on the market. In general, BPA does not develop these new resources itself. However, one of the programs that BPA is actively pursuing is a wind generation program. A recent Request for Proposals (RFP) resulted in 25 applications, proposing 2,600 megawatt (MW) of installed capacity, with expansion potential of over 4,000 MW. Each of those proposals will be evaluated and the promising proposals will be pursued. BPA is also responding to widespread interest in increasing the generating capacity at the federally owned hydroelectric projects in the region by conducting assessments of the costs and feasibility of such additions. BPA must allow market forces to supply the incentive that would lead resource developers to build new generation in the Northwest.

Some interest has been expressed in looking at the old nuclear plants that were begun over 20 years ago. To date, no feasible proposal at reasonable costs embodying current technology has been put forth. If such a proposal is made by a resource developer, BPA would be interested in discussing potential purchases further. BPA does not intend to initiate such development itself. BPA also does not contract for power with individual homeowners. Interested citizens may wish to contact their local utility for assistance in installing alternative and renewable energy resources.

**Issue: Rate Increase**

<b>Rate Increase</b>	<b>Letters Comments</b>	<b>Field Hearing Comments</b>
a. Do not raise rates; do not raise rates to serve Californians; investigate price gouging, antitrust issues	21	
b. Make rate increase variable; temporary	5	

## **Discussion**

Commenters offered opinions on BPA's sales to California during the summer of 2000, and during the power emergencies of winter of 2001. They believe that BPA sales to California have reduced the amount of power that will be available for sale in the Pacific Northwest (PNW), and attribute the proposed 2002 rate increase to those sales to California.

It is true that during the summer of 2000, BPA did make some sales of power to California. As the financial situation worsened there, BPA switched to an exchange rather than an outright sale of power. Under the exchange, for each unit of power that BPA shipped to California over the Intertie, California was obligated to return two units – one of those within 24 hours, and the other at some mutually agreeable time. This exchange actually resulted in BPA having more power for sale in the Northwest than it would have had without the exchange. The additional power returned here during periods when California did not need the power was stored in BPA's reservoirs as water to help fish and other uses of the river during a dry period. This stored water reduced the amount of power that BPA had to purchase on the open market, and actually helped keep prices down for the 2001 period. BPA will continue to participate in mutually beneficial exchanges with other regions.

Commenters also noted an article in which former Senator Hatfield suggested that excess BPA revenues should be spent on social programs. BPA is not aware of such discussions occurring within the Department of Energy, and is not proposing to establish such a program in this rate case. Under BPA's Supplemental Proposal, if BPA collects excess revenues, they are returned to the customers under the Dividend Distribution Clause.

Commenters also suggested that any rate increases be temporary and variable. This suggestion has considerable merit, and has been adopted. Chapter 4.3 of this Draft Supplemental ROD discusses the three kinds of CRACs that are being proposed. The need for an adjustment to the rates is assessed every six months in an effort to respond to changing market circumstances.

## **Issue: Conservation**

<b>Conservation</b>	<b>Letters Comments</b>	<b>Field Hearing Comments</b>
Encourage conservation	8	

## **Discussion**

Commenters suggested ways in which the PNW can reduce the potential rate increase by undertaking conservation programs. These commenters encourage individuals, businesses, government, and BPA to reduce electricity loads in the Northwest through energy conservation.

BPA agrees that conservation is an important component of managing the balance of electricity supply and demand in the Northwest. BPA has launched a conservation and renewables discount program whereby customers receive a 0.5 mill discount off their power rates if they use the funds

for conservation and/or renewable resources initiatives. In addition, BPA issued a request for conservation proposals to customers under which it is willing to fund cost-effective conservation for up to 10 years. Examples of other energy efficiency related actions BPA has taken include: working with its utilities to promote conservation through a regionwide advertising program, subsidizing the installation of compact fluorescent light bulbs throughout the Northwest, sponsoring a regionwide program to install VendingMi\$ers, and actively collaborating with the U.S. Army Corps of Engineers and the Bureau of Reclamation to efficiently use electricity at the hydroelectric projects. BPA also provides funding for a low income weatherization program run by the four PNW states. In addition, BPA supports the Northwest Energy Efficiency Alliance as it seeks to change electricity consumption and behaviors through market transformation. It is also true that as prices increase, consumers (including state and city governments) respond to price signals, and seek ways to reduce their own consumption. One side effect of the rate proposal, assuming that the LB CRAC results in increases in rates, should be additional conservation as individuals and businesses look for ways to operate more efficiently.

**Issue: Fish and Wildlife**

<b>Fish and Wildlife</b>	<b>Letters Comments</b>	<b>Field Hearing Comments</b>
a. Serve people over fish	3	
b. Do not produce power at the expense of fish	2	
c. Pursue section 4(h)(10)C credit	1	

**Discussion**

Commenters generally present two opposing viewpoints on the relationship between the use of the water in the rivers for power generation and for fish. Some believe that when there is a limited resource such as water, the health and welfare of humans should take priority. Others express a concern about the plight of fish, and offer to make sacrifices if that frees up water that could be made available for the fish.

Hydro operations as expressed in the federal implementation of the National Marine Fisheries Service and U.S. Fish and Wildlife Service Biological Opinions on the operation of the Federal Columbia River Power System are outside the scope of this rate case. However, BPA, in fulfilling its statutory responsibilities, seeks to meet its responsibilities for both fish and wildlife and power system reliability. BPA works with other federal agencies and regional interests to implement a plan that supports the needs of the fish, while acknowledging that there are times when human safety and well-being cannot be compromised. BPA is extremely concerned about the possibility of rolling blackouts, as have been experienced in California, during a low water year.

One commenter inquired whether BPA had considered using its accumulated section 4(h)(10)(C) credits for making its 2001 Treasury Payment. BPA is currently holding discussions with the U.S. Treasury to assess the feasibility of using those credits. That decision is, however, outside the scope of this rate case.

**Issue: Direct Service Industries (DSIs)**

<b>Direct Service Industries (DSIs)</b>	<b>Letters Comments</b>	<b>Field Hearing Comments</b>
a. Buy out DSIs	1	
b. Do not let DSIs sell their power; do not buy power for DSIs; no special rates for DSIs	7	
c. Let DSIs sell their power	1	

**Discussion**

Commenters expressed a range of opinions about the role of the DSIs in developing BPA’s rate proposal. One commenter suggested that BPA should buy out the contracts of the DSIs so that they will not be served during the coming rate period. A number of others were much more restrictive in their suggestions about how BPA should provide power for the DSIs. And finally, one commenter supplied promotional material from Kaiser Aluminum that supported letting the DSIs re-market their power from BPA.

BPA has been quite candid about the gap between its available resources, and the amount of power that it must purchase on the open market. BPA has publicly released estimates showing how large the LB CRAC might have to be in order to serve the increased load. BPA has also requested support from the region in reducing this load. One of the proposals has included requesting the DSIs to voluntarily shut down their facilities and accept a buyout from BPA for up to two years, although the decision of any customer of how much load it will place on BPA is outside the scope of this rate case. The proposal described in this Final Supplemental ROD is essentially a formula that will be adjusted to reflect the actual costs of serving all load placed on BPA. Thus this rate case does not directly address the question of whether to serve the DSIs, but establishes a mechanism that accounts for BPA’s costs. To the extent the load placed on BPA is reduced by customer decisions, the rate adjustment will be lower. Provisions in the DSI contracts regarding the re-marketing of federal power are also outside the scope of this rate case.

**Issue: Augmentation**

<b>Augmentation</b>	<b>Letters Comments</b>	<b>Field Hearing Comments</b>
a. Reduce commitment for resources	3	
b. Purchase assured load reductions	1	
c. Have a six month true-up for augmentation	1	

**Discussion**

Commenters understand that the need for additional resources is the primary driver for the LB CRAC. They suggest alternatives for reducing the amount of power that must be purchased at the current high prices to augment the existing resources of the federal system. Some

commenters believe that the DSIs should not be served. Another commenter proposes that BPA purchase the loads of certain customers through buy-down programs. One commenter proposes a flexible adjustment that only raises rates as they are needed to reflect the actual loads and the cost of power in the market.

BPA agrees that the size of the load directly translates into the amount of power that must be purchased beyond the generating ability of the federal system. That is why the proposal in this rate case is focused on a formula that tracks loads and costs and adjusts rates in six-month cycles, rather than trying to forecast a rate for the entire five-year rate period. In an effort outside the scope of this rate case, BPA staff is working with the customers to refine their load estimates, and has publicly asked all customer classes to reduce the load they will place on BPA. Customers may choose to practice conservation to reduce demand, may choose to purchase additional power from other resource developers, or may voluntarily shut down load. Some of BPA’s efforts include an irrigation buy-down program which both reduces load and frees up water for additional generation, and a public request to the DSIs to participate in a buy-down program for up to two years. The results of these efforts will be reflected in the first LB CRAC which takes effect on October 1, 2001.

**Issue: Northwest Economy**

<b>Northwest Economy</b>	<b>Letters Comments</b>	<b>Field Hearing Comments</b>
Increased rates will have severe impacts on the Northwest Economy	11	

**Discussion**

Commenters raise a range of concerns about the impacts of rate increases on different end-use consumers. A number of commenters are located in Rupert, Idaho, and others are served by the Nespelem Valley Electric Co-Operative in Nespelem, Washington – both small communities. They comment on the effects of a large rate increase on farmers, tribal members, small businesses, municipal services, realtors, and others.

BPA is aware that the effect of large rate increases can be difficult for small consumers to absorb. BPA is addressing this issue on two fronts. The first, at the larger level, is to work to reduce the amount of the increase by working at the wholesale level to reduce the amount of load that must be served. There are a number of efforts outside the rate case identifying these options, as noted above. The second approach is an extensive effort between BPA and the utilities to develop conservation programs to help the end-user find ways to reduce their own consumption at the retail level, thus mitigating at least some of the effects of the rate increase.

## 10.0 CONCLUSION

As required by law, the adjustment to base rates established and adopted in this ROD has 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, this adjustment to base rates has been designed to be as low as possible consistent with sound business principles, to encourage the widest possible use of BPA's power and to satisfy BPA's other ratemaking obligations. The Hearing Officer has assured that all interested parties and participants were afforded the opportunity for a full and fair evidentiary hearing, as required by law.

BPA must evaluate the proposed adjustment to base 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 General Rate Schedule Provisions as Bonneville Power Administration's 2002 final adjustment to the base power rates 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 20<sup>th</sup> day of June, 2001.

  
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Acting Administrator and Chief Executive Officer

# 2002 Supplemental Power Rate Proposal Appendix to Administrator's Final Record of Decision

WP-02-A-09

June 2001





**2002 FINAL SUPPLEMENTAL GENERAL RATE SCHEDULE PROVISIONS**

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## GENERAL RATE SCHEDULE PROVISIONS ACRONYMS LIST

AAMTA	Augmentation Amount Actual
AAMTF	Augmentation Amount Forecast
AANR	Audited Accumulated Net Revenues
ACTUALLBCREVREQ	Actual Load-Based Cost Recovery Adjustment Clause Revenue Required
ACTUALLBCREVREQ(NS)	Actual Load-Based Cost Recovery Adjustment Clause Revenue Required (non-Slice)
ACTUALLBCREVREQ(S)	Actual Load-Based Cost Recovery Adjustment Clause Revenue Required (Slice)
ADJUST(NS)	Adjustment to a Purchaser's Non-Slice Monthly Bill
ADJUST(S)	Adjustment to a Purchaser's Slice Monthly Bill
aMW	Average Megawatt
ANR	Accumulated Net Revenues
APP	Augmentation Pre-Purchase
BPA	Bonneville Power Administration
BUYDOWN	Cost of Load Buydown
C&R Discount	Conservation and Renewables Discount
C&R(NS)	Conservation and Renewables Discount–Non-Slice
C&R(S)	Conservation and Renewables Discount–Slice
CRAC	Cost Recovery Adjustment Clause
CUSTREV(NS)	Customer Revenue with LB CRAC–Non-Slice
CUSTREV(S)	Customer Revenue with LB CRAC–Slice
DDC	Dividend Distribution Clause
DIURNALACA	Diurnal Augmentation Cost Actual
DIURNALACF	Diurnal Augmentation Cost Forecasted
DSIs	Direct Service Industrial Customers
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
FCRPS	Federal Columbia River Power System
FERC	Federal Energy Regulatory Commission
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GRSPs	General Rate Schedule Provisions
HLH	Heavy Load Hour
IP	Industrial Firm Power (rate)
IPTAC	Industrial Firm Power Targeted Adjustment Charge
IOUs	Investor-Owned Utilities
kW	Kilowatt (1,000 watts)
kWh	Kilowatthour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LB CRAC%	Percent applied to sales revenue for loads subject to the LB CRAC
LBCREV(NS)	LB CRAC Revenues (Non-Slice) Received by BPA
LBCREV(S)	LB CRAC Revenues [Slice] Received by BPA

LDD(NS)	Low Density Discount non-Slice
LDD(S)	Low Density Discount Slice
LLH	Light Load Hour
LOAD(NS)	Non-Slice Load Subject to LB CRAC
LOAD(S)	Slice Load Subject to LB CRAC
May Proposal	May 2000 Final Power Rate Proposal
MARRA	Monthly Augmentation Resale Revenues Actual
MARRF	Monthly Augmentation Resale Revenues Forecasted
Mid-C	Mid-Columbia
MSC	Monthly System Capability
MW	Megawatt (1 million watts)
MWh	Megawatthour
NACA	Net Augmentation Cost Actual
NACDIFF	Net Augmentation Cost Difference
NACF	Net Augmentation Cost Forecasted
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NR	New Resource Firm Power
NSL(A)	Actual Non-Slice Load
NSL(F)	Forecasted Non-Slice Load
OC	Option Costs
PF	Priority Firm Power (rate)
PRICE	Price for Augmentation Amounts Not Pre-Purchased
RATE(NS)	Non-Slice Rates Without LB CRAC
RATE(S)	Slice Rates Without LB CRAC
REP	Residential Exchange Program
REP Settlement	Investor-Owned Utilities Residential Exchange Program Settlement
REVDIFF(NS)	Revenue Difference Non-Slice
REVDIFF(S)	Revenue Difference Slice
REVRATE(NS)	Adjusted Non-Slice Rates
REVRATE(S)	Adjusted Slice Rate
REVw/LBC(NS)	Actual non-Slice Revenues
REVw/LBC(S)	Actual Slice Revenues
REVw/oLBC(NS)	Baseline Non-Slice Revenues
REVw/oLBC(S)	Baseline Slice Revenues
RL	Residential Load (rate)
ROD	Record of Decision
SALESMA YAUGA	Actual Sales of Existing Augmentation Quantity
SALESMA YAUGF	Forecasted Sales of Existing Augmentation Quantity
SALESNE WAUGA	Actual Sales of New Augmentation Quantity
SALESNE WAUGF	Forecasted Sales of New Augmentation Quantity
Slice	Slice of the System product
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
TAUGCA	Total Augmentation Cost Actual
TAUGCF	Total Augmentation Cost Forecasted
TARRA	Total Augmentation Resale Revenue Actual

TARRF	Total Augmentation Resale Revenue Forecasted
TCAPPA	Total Cost of Augmentation Pre-Purchases Actual
TCAPPF	Total Cost of Augmentation Pre-Purchases Forecasted
TREV <sub>w</sub> /LBC(NS)	Total Revenues for Non-Slice With LB CRAC
TREV <sub>w</sub> /LBC(S)	Total Revenues for Slice with LB CRAC
TTREV <sub>w</sub> /LBC	Total Revenues with LB CRAC
TREV <sub>w/o</sub> LBC(NS)	Total Non-Slice Revenues Without LB CRAC
TREV <sub>w/o</sub> LBC(S)	Total Slice Revenues without LB CRAC
TTREV <sub>w/o</sub> LBC	Total Revenues without LB CRAC
TLA	Transmission Loss Adjustment

## 2002 FINAL SUPPLEMENTAL GENERAL RATE SCHEDULE PROVISIONS

### A. *Introduction*

The following section (Part B below) contains Bonneville Power Administration's (BPA) proposed final supplemental revisions to BPA's proposed 2002 General Rate Schedule Provisions (GRSPs) for power rates.

The proposed GRSPs were prepared in accordance with BPA's statutory authority to develop rates. 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).

BPA's 2002 proposed revisions to the GRSPs will supersede BPA's 1996 rate schedules, except for the FPS-96 rate schedule. The FPS-96 rate schedule continues in effect as modified in Docket No. FPS-96R. BPA proposes that its revised GRSPs become effective upon interim approval or upon final confirmation and approval by FERC. BPA currently anticipates that it will request FERC approval of its revised GRSPs effective October 1, 2001.

### B. *BPA's Final Supplemental Revisions to the 2002 General Rate Schedule Provisions for Power Rates*

*Revisions to:*

## SECTION II: ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

### F. **Cost Recovery Adjustment Clause**

There are three sets of conditions under which rate increases under Cost Recovery Adjustment Clause (CRAC) may trigger. The first is the Load-Based CRAC (LB CRAC), which triggers if BPA's augmentation cost exceeds the amount forecast in the May Proposal. The second is the Financial-Based CRAC (FB CRAC), which triggers based on the generation function's forecasted level of accumulated net revenues. The third is the Safety-Net CRAC (SN CRAC), which triggers when, after implementation of the LB and FB CRACs, BPA has or reasonably expects to miss a payment to the Treasury or another creditor.

## 1. **Load-Based Cost Recovery Adjustment Clause**

### a. **Application of the Load-Based Cost Recovery Adjustment Clause**

The LB CRAC is a percentage rate adjustment based on BPA's cost of acquiring power to meet BPA's contractual obligations to serve loads in excess of the expected firm capability of the Federal Columbia River Power System (FCRPS).

The LB CRAC will be calculated and applied to the following rates for sales of energy, capacity, and load variance: PF [Preference, 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), New Resource Firm Power (NR-02), and Subscription purchases under Firm Power Products and Services (FPS), excluding revenues generated by the FB CRAC, SN CRAC, and distributions under Dividend Distribution Clause (DDC).

The LB CRAC applies to the 1,000 average megawatts (aMW) power sale portion of the Residential Exchange Program (REP) Settlement, including where power sales are converted to cash payments calculated pursuant to Section 5(b) of the Residential Exchange Settlement Agreement. The LB CRAC will also apply to the Priority Firm Slice Rate, excluding revenues from the contractual true-up pursuant to the Slice Agreement, and payments pursuant to section T of these GRSPs.

The LB CRAC does not apply to power sales under Pre-Subscription contracts to the extent prohibited by such contracts, the 900 aMW of monetary benefits provided under the financial portion of the REP Settlement, or to BPA's current contractual obligations for Seasonal Irrigation Mitigation sales, including for any eligible customer that converts from Slice to another BPA product.

### b. **Definitions**

- (1) (AAMTA) "Augmentation Amount Actual" means the amount of actual augmentation required as determined in section f(1) of these GRSPs.
- (2) (AAMTF) "Augmentation Amount Forecast" means the forecasted augmentation as determined in section d of these GRSPs.
- (3) (ACTUALLBCREVREQ) "Actual LB CRAC Revenue Required" means an amount equal to the actual costs incurred by BPA to

acquire AAMTA during any six-month period, and is equal to the sum of ACTUALLBCREVREQ(NS) [for Non-Slice products] and ACTUALLBCREVREQ(S) [for the Slice product].

- (4) (ACTUALLBCREVREQ(NS)) “Actual LB CRAC Revenue Required (Non-Slice)” means the portion of the actual costs incurred by BPA to acquire AAMTA during any six-month period purchases apportioned to Non-Slice Rates.
- (5) (ACTUALLBCREVREQ(S)) “Actual LB CRAC Revenue Required (Slice)” means the portion of the actual costs incurred by BPA to acquire AAMTA during any six-month period that is apportioned to Slice.
- (6) ADJUST(NS)) “Adjustment to a Purchaser’s Non-Slice Monthly Bill” means the adjustment to a customer’s monthly power bill for the purchase of energy, capacity and load variance products under Non-Slice Rates in an amount equal to one-sixth (1/6) of the customer’s share of the Revenue Difference (REVDIFF[NS]) for the preceding six-month period.
- (7) (ADJUST(S)) “Adjustment to a Purchaser’s Slice Monthly Bill” means the adjustment to a customer’s monthly power bill for purchases under Slice in an amount equal to the customer’s share of REVDIFF(S) for the preceding six-month period.
- (8) (APP) “Augmentation Pre–Purchase” means the quantity of power under a contract or other binding obligation entered into by BPA at least 120 days prior to the first day of the month for the delivery of AAMTF for a given month.
- (9) (BUYDOWN) “Cost of Load Buydown” means the costs that BPA incurs to reduce or eliminate its contractual obligation to deliver firm power to regional customers and thereby lower the AAMTF or AAMTA for a month.
- (10) (C&R(NS)) “Conservation and Renewables Discount–Non-Slice” means the total dollars actually credited to all Non-Slice purchasers under the Conservation & Renewable Discount.
- (11) (C&R(S)) “Conservation and Renewables Discount–Slice” means the total dollars actually credited to all Slice purchasers under the Conservation & Renewables Discount.

- (12) (CUSTREV(NS)) “Customer Revenue with LB CRAC–Non-Slice” means the actual revenues received by BPA from each customer for a given six-month period for the purchase of energy, capacity and load variance service at Non-Slice Rate subject to the LB CRAC, reduced by any C&R(NS) and LDD(NS).
- (13) (CUSTREV(S)) “Customer Revenue with LB CRAC - Slice” means the actual revenues received by BPA from each customer for a given six-month period for purchases at the Slice rate subject to the LB CRAC, reduced by any C&R(S) and LDD(S).
- (14) (DIURNALACA) “Actual Diurnal Augmentation Cost” means the diurnal cost, in dollars, actually incurred by BPA to acquire AAMTA. Diurnal costs are calculated using monthly flat AAMTA and the diurnal cost of acquiring that AAMTA.
- (15) (DIURNALACF) “Diurnal Augmentation Cost Forecast” means the diurnal cost, in dollars, that BPA forecasts it will incur to acquire AAMTF. Diurnal costs are calculated using monthly flat AAMTF amounts and the diurnal cost of acquiring those AAMTF amounts.
- (16) (LB CRAC%) “LB CRAC Percentage” means the percentage produced by dividing Net Augmentation Costs Forecasted (NACF) by Total Revenues without LB CRAC (TTREVw/oLBC).
- (17) (LBCREV(NS)) “LB CRAC Revenues (Non-Slice) Received by BPA” means the amount of revenues actually received by BPA during any six-month period from the sale of energy, capacity and load variance services at Non-Slice Rates subject to the LB CRAC, as reduced by the C&R(NS) and LDD(NS).
- (18) (LBCREV(S)) “LB CRAC Revenues [Slice] Received by BPA” means the amount of revenues actually received by BPA during any six-month period from sales at the Slice rate (WP-A-02, Section II.D.2), reduced by the C&R(S) and LDD(S).
- (19) (LDD(NS)) “Low Density Discount Non-Slice” means the total dollars actually credited to all purchasers under Non-Slice Rates subject to the LB CRAC under the Low Density Discount.
- (20) (LDD(S)) “Low Density Discount Slice” means the total dollars actually credited to all purchasers under the Slice rate under the Low Density Discount.



- (21) (LOAD(NS)) “Non-Slice Load Subject to LB CRAC” means the loads that are served by BPA at Non-Slice Rate that are subject to the LB CRAC.
- (22) (LOAD(S)) “Slice Load Subject to LB CRAC” means loads that are served by BPA at the Slice rate. LOAD[S] is initially 2,000 aMW, but will be adjusted to reflect contracted Slice loads prior to October 1, 2001.
- (23) (MARRA) “Monthly Augmentation Resale Revenues Actual” means the actual monthly resale revenues determined by multiplying the: (a) sum of: (i) Sales of Existing Augmentation Quantity (SALESMA YAUGA) multiplied by \$28.10; and (ii) Sales of New Augmentation Quantity (SALESNEWAUGA) multiplied by \$19.26; by (b) the number of hours in the month.
- (24) (MARRF) “Monthly Augmentation Resale Revenues Forecasted” means the forecasted monthly resale revenues determined by multiplying the: (a) sum of: (i) Sales of Existing Augmentation Quantity (SALESMA YAUGF) multiplied by \$28.10; and (ii) Sales of New Augmentation Quantity (SALESNEWAUGF) multiplied by \$19.26; by (b) the number of hours in the month.
- (25) (MSC) “Monthly System Capability” means the monthly value obtained by shaping the firm system capability to BPA’s firm monthly loads, where firm system capability equals 7,070 aMW of FCRPS capability, less the amount of such capability sold to Slice purchasers. A separate shape will be produced for each separate year in the rate period. These monthly amounts of MSC are established once in the Supplemental Rate Case ROD.
- (26) (NACA) “Net Augmentation Cost Actual” means the additional augmentation costs that are actually required to be recovered through application of the LB CRAC. NACA is determined separately for each month in any given six-month period.
- (27) (NACF) “Net Augmentation Cost Forecast” means the forecast of additional augmentation costs that are required to be recovered through application of the LB CRAC. NACF is forecasted separately for each month in any given six-month period.
- (28) (NACDIFF) “Net Augmentation Cost Difference” means the difference between NAC(120) and NAC(0).

- (29) (NSL(A)) “Actual Non-Slice Load” means the actual amount of load served by BPA under Non-Slice Rates during a six-month period.
- (30) (NSL(F)) “Forecasted Non-Slice Load” means the amount of load served by BPA during a six-month period under Non-Slice Rates.
- (31) “Non-Slice Rates” means all BPA firm power rates, other than the PF Slice Rate and includes PF Preference, PF Exchange Program, PF Exchange Subscription, Industrial Firm Power, Industrial Firm Power Targeted Adjustment Charge and Industrial Firm Power Cost Based Index, Residential Load, New Resource Firm Power and the Firm Power Products and Services Rates.
- (32) (OC) “Option Costs” means the costs actually incurred or revenues received by BPA by entering into physical or financial option contracts, or other financial contracts, or to reduce the cost of acquiring the cost of AAMTA or AAMTF.
- (33) (PRICE) “Price For Forecasted Augmentation Amounts Not Pre-Purchased” means the forward price per megawatthour (MWh) used by BPA to determine the cost of purchasing power equal to the amount by which AAMTF exceeds APP. The PRICE will be established by BPA through the use of documented quotes for specific quantities from brokers or marketers or publicly available forward price indices. In each case, it is for electricity delivered at the Mid-Columbia market hub.
- (34) (RATE(NS)) “Non-Slice Rates Without LB CRAC” means the Non-Slice rates established by BPA in May 2000 in the Administrator’s Record of Decision in BPA Docket WP-02.
- (35) (RATE(S)) “Slice Rate without LB CRAC” means the Slice rate established by BPA in May 2000 in the Administrator’s Record of Decision in BPA Docket WP-02.
- (36) (REVDIFF(NS)) “Revenue Difference Non-Slice” means the amount by which actual LBCREV(NS) exceeds or is less than ACTUALLBCREVREQ(NS) during any six-month period.
- (37) (REVDIFF(S)) “Revenue Difference Slice” means the amount by which actual LBCREV(S) exceeds or is less than ACTUALLBCREVREQ(S) during any six-month period.

- (38) (REVRATE(NS)) “Adjusted Non-Slice Rates” means the Non-Slice Rates that will apply to sales of energy, capacity and load variance products during the immediately upcoming six-month period.
- (39) (REVRATE(S)) “Adjusted Slice Rate” means the Slice rate that will apply to sales of the Slice product during the immediately upcoming six-month period.
- (40) (REVw/LBC(NS)) “Actual Non-Slice Revenues” means the monthly revenues actually received by BPA from sales of energy, capacity and load variance products during any six-month period, reduced by the C&R(NS) and LDD(NS).
- (41) (REVw/LBC(S)) “Actual Slice Revenues” means the monthly revenues actually received by BPA from sales of the Slice product during any six-month period reduced by C&R(S) and LDD(S).
- (42) (REVw/oLBC(NS)) “Baseline Non-Slice Revenues” means the monthly revenues received by BPA from sales of energy, capacity and load variance products subject to LB CRAC using RATE(NS) during any given six-month period reduced by the C&R(NS) and LDD(NS).
- (43) (REVw/oLBC(S)) “Baseline Slice Revenues” means the monthly revenues received by BPA from sales of the Slice product during any given six-month period calculated using RATE(S), reduced by the C&R(S) and LDD(S).
- (44) (SALESMAYAUGA) “Actual Sales of Existing Augmentation Quantity” means the resale of augmentation of 1,745 aMW minus [(actual DSI load/1486) \* 450].
- (45) (SALESMAYAUGF) “Forecasted Sales of Existing Augmentation Quantity” means the resale of augmentation of 1,745 aMW minus [(forecasted DSI load/1486) \* 450].
- (46) (SALESNEWAUGA) “Sales of New Augmentation Quantity Actual” means the actual monthly amount (in aMW) by which AAMTA is greater than the amount in SALEMAYAUGA.
- (47) (SALESNEWAUGF) “Sales of New Augmentation Quantity Forecasted” means the forecasted monthly amount (in aMW) by which AAMTF is greater than the amount in SALEMAYAUGF.

- (48) (TAUGCA) “Total Augmentation Cost Actual” means the sum of the monthly DIURNALACA, BUYDOWN and OC amounts for a given six-month period.
- (49) (TAUGCF) “Total Augmentation Cost Forecast” means the sum of the monthly DIURNALACF, BUYDOWN, and OC amounts for a given six-month period.
- (50) (TARRA) “Total Augmentation Resale Revenue Actual” means the sum of the separate monthly MARRA amounts for a given six-month period.
- (51) (TARRF) “Total Augmentation Resale Revenue Forecasted” means the sum of the separate monthly MARRF amounts for a given six-month period.
- (52) (TCAPPA) “Total Cost of Augmentation Pre-Purchases Actual Non-Slice” means the actual total cost to acquire APPA(NS).
- (53) (TCAPPF) “Total Cost of Augmentation Pre-Purchases Forecasted” means the forecasted total cost of the APP made for a month.
- (54) (TREVw/LBC(NS)) “Total Revenues for Non-Slice With LB CRAC” means the sum of all REVw/LBC(NS) for any given six-month period.
- (55) (TREVw/LBC(S)) “Total Revenues for Slice with LB CRAC” means the sum of all REVw/LBC(S) for any given six-month period.
- (56) (TTREVw/LBC) “Total Revenues with LB CRAC” means the sum of TREVw/LBC(S) and TREVw/LBC(NS).
- (57) (TREVw/oLBC(NS)) “Total Non-Slice Revenues Without LB CRAC” means the sum of all REVw/oLBC(NS) for any given six-month period.
- (58) (TREVw/oLBC(S)) “Total Slice Revenues without LB CRAC” means the sum of all REVw/oLBC(S) for any given six-month period.
- (59) (TTREVw/oLBC) “Total Revenues without LB CRAC” means the sum of TREVw/oLBC(S) and TREVw/oLBC(NS).

- (60) (TLA) “Transmission Loss Adjustment” means the Network loss factor adjustment applied under applicable BPA Transmission Business Line tariffs.

c. **Procedure**

Step One below addresses the calculations for determining the LB CRAC percentages that will apply to each six-month period. Step Two below addresses the determination of any rebate or surcharge due to actual LB CRAC exceeding or falling short of the actual costs incurred by BPA to acquire power after the end of the preceding six-month period. This section also describes the procedure by which BPA will provide public process on the application of the LB CRAC.

- (1) Step One is calculation of the LB CRAC percentage and resulting adjustment to the rates that will be applied in each six-month period. On or about 90 days prior to the beginning of each six-month period (or in the case of the calculation of the LB CRAC to be applied for the period April 1 through September 30, 2002, on or about 45 days prior to the beginning of that second six-month period), BPA will establish the LB CRAC percentage and resulting adjustment to the rates that will apply to the sale of products under rates subject to the LB CRAC during upcoming six-month period. Using the process described in c(3) below, BPA will determine what data must be revised to develop the LB CRAC for the next six-month period. As a result of rate mitigation efforts, the Step One analysis will occur in two parts. This two-part process is designed to address the problem of some rate mitigation contracts containing pricing that is itself tied to the LB CRAC. For power buybacks made at a premium above the base rate plus the LB CRAC, in part one, BPA will: (a) include the premium portion of any such agreement; and (b) exclude the quantities of any such agreement from the calculation of REVw/LBC(S) and REVw/oLBC(NS). The increment in rates applicable to any such rate mitigation agreement from part one will then be added to the cost of meeting augmentation used in the calculation of the LB CRAC% in part two. Then, in part two the LB CRAC% and REVRATE will be determined. It is this set of adjusted rates that will appear on customer’s bills.
- (2) Step Two is the calculation of the amount by which actual LB CRAC revenues exceeded or fell short of the actual costs incurred by BPA to acquire power for the most recently concluded six-month period. As is described below, this calculation does not require a new calculation of the LB CRAC percentage or rates.

The amount by which actual LB CRAC revenue exceeded or fell short of actual power costs will be established on or about 90 days after the end of the most recent six-month period. Any such excess or shortfall will be treated separately from any LB CRAC adjustment for the upcoming six-month period. A part of this determination involves revising data from that used to develop the LB CRAC in c(1) immediately above.

- (3) Fifteen days prior to the date that BPA must establish the LB CRAC Percentage pursuant to paragraph c(1) above, and any charge or rebate for the amount of any excess or short-fall from the preceding six-month period, BPA will conduct a publicly noticed workshop. For the calculations to be performed for the first six-month period, BPA shall hold two workshops approximately 14 days apart, with the first workshop on or about June 6, 2001. The purpose of the workshop before a six-month period will be to provide customers with information used by BPA to develop the LB CRAC Percentage and adjusted rates for the next six-month period. The information used to perform these calculations will be provided to customers at a quarterly level of aggregation. The purpose of the workshop after a six-month period will be to determine any additional charge or rebate due individual customers for any excess or shortfall of actual LB CRAC revenue to cover NACA from the preceding six-month period. The information used to perform these calculations will be at a quarterly level of aggregation (including total and individual customer revenues used for such calculations). These workshops will provide customers with an opportunity to ask questions about BPA's calculations, and to provide BPA with information relevant to the calculation of the LB CRAC Percentage, adjusted rates, and any proposed charge or rebate.

d. **Revenue and cost calculations performed before each six-month period**

Before the six-month period, these calculations are performed with forecasted amounts to determine the LB CRAC Percentage and revised rates to be applied to purchaser bills during that period.

- (1) Calculating AAMTF

This is a two-step process.

- (i) Step One – Forecasted Non-Slice Loads (NSL(F))

In this step, BPA will determine what, if any, changes are required in the Forecasted Non-Slice loads contained in the Supplemental ROD.

- (ii) Step Two – Forecasted Augmentation Amount (AAMTF)

For each month separately,  $AAMTF = (NSL(F) - MSC) * (1 + TLA)$

- (2) Calculating the DIURNALACF

In this calculation, BPA establishes the costs it expects to incur to acquire AAMTF for each diurnal period for each month in the six-month period.

The following calculations will be separately performed for the HLH in a month and the LLH in each month in the next six-month period.

- (i) If APP is greater than AAMTF,  
 $DIURNALACF = (AAMTF/APP) * [TCAPPF]$

- (ii) If APP is equal to AAMTF,  
 $DIURNALACF = TCAPPF$

- (iii) If APP is less than AAMTF,  
 $DIURNALACF = [TCAPPF] + [(AAMTF-APP) * PRICE * Diurnal\ Hours]$

- (3) Calculating Total Augmentation Cost Forecast for a six-month period

BUYDOWN and OC obligations incurred as of the date of the forecast, and DIURNALCF monthly values for a six-month period will be summed to determine the Total Augmentation Cost Forecast (TAUGCF) for the six-month period.

$TAUGCF = \text{Sum of the six monthly } (DIURNALACF + BUYDOWN + OC)$

(4) Calculating Monthly and Total Augmentation Resale Revenues

This calculation establishes the resale revenue amount to be subtracted from TAUGCF for the six-month period.

The definitions of SALES MAYAUGF and SALES NEWAUGA for both the setting of the LB CRAC% and determining any credit or debit are modified to properly address the calculation of augmentation resale revenue to reflect rate mitigation.

$SALES MAYAUGF = \text{Minimum} [AAMTF, 1,745 \text{ aMW minus } [(forecasted \text{ DSI load}/1486) * 450].$

$SALES NEWAUGF = \text{MAX} [0, AAMTF - SALES MAYAUGF]$

$MARRF = [(SALES MAYAUGF * \$28.10) + (SALES NEWAUGF * \$19.26)] * \text{Hours in the month}$

$TARRF = \text{Sum of MARRF for each month in a six-month period}$

(5) Calculating Net Augmentation Cost Forecast for a six-month period

Once the TARRF is established, the NACF will be determined. This is the amount of forecasted costs that must be recovered in an LB CRAC mechanism.

$NACF = TAUGCF - TARRF$

(6) Calculating Monthly Revenues

This calculation determines the monthly revenues BPA receives from the sale of energy, capacity, and load variance products, including Slice, at rates that are subject to LB CRAC before the application of the LB CRAC.

For the Slice rate,

$REV_{w/oLBC}(S) = [RATE(S) * LOAD(S)] - LDD(S) - C\&R(S)$

Because the Slice rate is stated as \$/% per month,  $REV_{w/oLBC}(S)$ ,  $LOAD(S)$  is calculated using the percentage of Slice contracted, for example,  $28.29\% = 2,000 \text{ aMW of Slice}$ . For Slice calculations,  $LDD(S)$  and  $C\&R(S)$  are calculated as dollars. That is,  $LOAD(S) = (\text{actual Slice load}/7070)*100$ .



For Non-Slice Rates for Part One:

$$\text{REV}_{w/oLBC}(\text{NS}) = [\text{RATE}(\text{NS}) * \text{LOAD}(\text{NS}) * \text{Hours in month}] \\ - \text{LDD}(\text{NS}) - \text{C\&R}(\text{NS}) - ((\text{energy quantity of rate mitigation} \\ \text{deals tied to LB CRAC} * \$19.26/\text{MWh}))$$

For Non-Slice Rates for Part Two:

$$\text{REV}_{w/oLBC}(\text{NS}) = [\text{RATE}(\text{NS}) * \text{LOAD}(\text{NS}) * \text{Hours in month}] \\ - \text{LDD}(\text{NS}) - \text{C\&R}(\text{NS})$$

Because Non-Slice Rates are stated as \$/MWh and \$/kW-month, LOAD(NS) is expressed in MWh and kW for the month. LDD(NS) and C&R(NS) are values of the discounts in dollar amounts.

- (7) Calculating Total Revenues without the LB CRAC for a six-month period

$$\text{TREV}_{w/oLBC}(\text{S}) = \text{REV}_{w/oLBC}(\text{S}) \text{ for each month in} \\ \text{six-month period.}$$

$$\text{TREV}_{w/oLBC}(\text{NS}) = \text{REV}_{w/oLBC}(\text{NS}) \text{ for each month in} \\ \text{six-month period.}$$

$$\text{TTREV}_{w/oLBC} = \text{TREV}_{w/oLBC}(\text{S}) + \text{TREV}_{w/oLBC}(\text{NS})$$

e. **Calculation of the LB CRAC percentage and revised rates for Slice and Non-Slice products**

Calculations under this section e only occur once in advance of each six-month period to make the adjustment that will apply to the upcoming six-month period. When the six-month period is over, the calculations in section f are performed.

- (1) Calculating the LB CRAC Percentage

$$\text{LB CRAC}\% = \text{NACF}/\text{TTREV}_{w/oLBC}$$

- (2) Calculating the adjustment to RATE(NS) and RATE(S)

- (i) Slice Rate

The spreadsheet model defines a variable Multiplier(S) which equals the bracketed term:

$$\text{Multiplier (S)} = \{ [ ((\text{TREV}_{w/oLBC(S)} + \text{LDD(S)}) * \text{LB CRAC}\%) + (\text{TREV}_{w/oLBC(S)} + \text{C\&R(S)} + \text{LDD(S)}) ] / [ \text{TREV}_{w/oLBC(S)} + \text{C\&R(S)} + \text{LDD(S)} ] \}$$

$$\text{REVRATE(S)} = \text{RATE(S)} * \text{Multiplier(S)}$$

(ii) Non-Slice Rates

The spreadsheet model defines a variable Multiplier(NS) which equals the bracketed term:

$$\text{Multiplier (NS)} = \{ [ ((\text{TREV}_{w/oLBC(NS)} + \text{LDD(NS)}) * \text{LB CRAC}\%) + (\text{TREV}_{w/oLBC(NS)} + \text{C\&R(NS)} + \text{LDD(NS)}) ] / [ \text{TREV}_{w/oLBC(NS)} + \text{C\&R(NS)} + \text{LDD(NS)} ] \}$$

$$\text{REVRATE(NS)} = \text{RATE(NS)} * \text{Multiplier(NS)}$$

(3) Application of Revised Rates

The REVRATE(S) and REVRATE(NS) will replace the RATE(S) and RATE(NS), respectively, on purchaser's bills for products sold in the next six-month period that are subject to the LB CRAC.

f. **Calculations performed after the close of each six-month period**

After the six-month period, these calculations are performed with actual amounts to determine the amount of any adjustment to individual customer bills as a result of an over or under collection of LB CRAC revenues.

(1) Calculating AAMTA

This is a two-step process.

(i) Step One – Actual non-Slice Loads (NSL(A))

In this step, BPA will determine the actual non-Slice loads.

(ii) Step Two – Actual Augmentation Amount (AAMTA)

For each month separately,  $\text{AAMTA} = (\text{NSL(A)} - \text{MSC}) * (1 + \text{TLA})$ .

(2) Calculating DIURNALACA

In this calculation, BPA establishes the costs it actually did incur to acquire AAMTA for each diurnal period for each month in the six-month period.

The following calculations will be separately performed for the HLH in a month and the LLH in each month in the proceeding six-month period.

(i) If APP is greater than AAMTA,

$$\text{DIURNALACA} = (\text{AAMTA}/\text{APP}) * [\text{TCAPPA}]$$

(ii) If APP is equal to AAMTA,

$$\text{DIURNALACA} = \text{TCAPPA}$$

(iii) If APP is less than AAMTA,

$$\text{DIURNALACA} = [\text{TCAPPA}] + [(\text{AAMTA}-\text{APP}) * \text{PRICE} * \text{Diurnal Hours}]$$

(3) Calculating Total Augmentation Cost Actual for a six-month period

Once DIURNALACA, BUYDOWN, and OC are determined, these monthly values for a six-month period will be summed to determine the Total Augmentation Cost Actual (TAUGCA) for the six-month period.

$$\text{TAUGCA} = \text{Sum of the six monthly (DIURNALACA} + \text{BUYDOWN} + \text{OC)}$$

(4) Calculating Monthly and Total Augmentation Resale Revenues

This calculation establishes the resale revenue amount to be subtracted from TAUGCA for the six-month period.

$$\text{SALESMAAUGA} = \text{Minimum}[\text{AAMTA}, 1,745 \text{ aMW minus } [(\text{actual DSI load}/1486) * 450].$$

$$\text{SALESNEWAUGA} = \text{MAX}[0, \text{AAMTA} - \text{SALESMAAUGA}]$$

$$\text{MARRA} = [(\text{SALESMA YAUGA} * \$28.10) + (\text{SALESNEWAUGA} * \$19.26)] * \text{Hours in the month}$$

TARRA = Sum of MARRA for each month in a six-month period

(5) Calculating Net Augmentation Cost Actual for a six-month period

Once the TARRA is established, the NACA will be determined. This is the actual costs that must be recovered in an LB CRAC mechanism.

$$\text{NACA} = \text{TAUGCA} - \text{TARRA}$$

(6) Calculating Monthly Revenues

- (i) This calculation determines the monthly revenues BPA *would have* received from the sale of energy, capacity, and load variance products, including Slice, at rates that are subject to LB CRAC before the application of the LB CRAC, but using actual loads.

For the Slice rate,

$$\text{REV}_{w/oLBC}(S) = [\text{RATE}(S) * \text{LOAD}(S)] - \text{LDD}(S) - \text{C\&R}(S)$$

Because the Slice rate is stated as \$/% per month,  $\text{REV}_{w/oLBCS}$ ,  $\text{LOAD}(S)$  is calculated using the percentage of Slice contracted, for example, 28.29% = 2,000 aMW of Slice. That is,  $\text{LOAD}(S) = (\text{actual Slice load}/7070) * 100$ .

For Non-Slice rates,

$$\text{REV}_{w/oLBC}(NS) = [\text{RATE}(NS) * \text{LOAD}(NS) * \text{Hours in month}] - \text{LDD}(NS) - \text{C\&R}(NS)$$

Because Non-Slice rates are stated as mills/kWh and \$/kW-month,  $\text{LOAD}(NS)$  is expressed in kWh and kW for the month.

(ii) Calculating Actual Monthly Revenues received

This calculation determines the monthly revenues BPA *actually did* receive from the sale of energy, capacity, and

load variance products, including Slice, at rates that are subject to LB CRAC *after* the application of the LB CRAC, but using actual loads.

For the Slice rate,

$$\text{REVw/LBC(S)} = [\text{REVRATE(S)} * \text{LOAD(S)}] - \text{LDD(S)} - \text{C\&R(S)}$$

Because the Slice rate is stated as \$/% per month, REVw/oLBCS, LOAD(S) is calculated using the percentage of Slice contracted, for example, 28.29% = 2,000 aMW of Slice. That is,  $\text{LOAD(S)} = (\text{actual Slice load}/7070) * 100$ .

For Non-Slice rates,

$$\text{REVw/LBC(NS)} = [\text{REVRATE(NS)} * \text{LOAD(NS)} * \text{Hours in month}] - \text{LDD(NS)} - \text{C\&R(NS)}$$

Because Non-Slice rates are stated as \$/MWh and \$/kW-month, LOAD(NS) is expressed in MWh and kW for the month.

(7) Calculating Total Revenues for a six-month period

(i) Without the LB CRAC applied

$\text{TREVw/oLBC(S)} = \text{REVw/oLBC(S)}$  for each month in six-month period.

$\text{TREVw/oLBC(NS)} = \text{REVw/oLBC(NS)}$  for each month in six-month period.

$$\text{TTREVw/oLBC} = \text{TREVw/oLBC(S)} + \text{TREVw/oLBC(NS)}$$

(ii) With the LB CRAC applied

$\text{TREVw/LBC(S)} = \text{REVw/LBC(S)}$  for each month in six-month period.

$\text{TREVw/LBC(NS)} = \text{REVw/LBC(NS)}$  for each month in six-month period.

$$\text{TTREVw/LBC} = \text{TREVw/LBC(S)} + \text{TREVw/LBC(NS)}$$

g. **Determining the surcharge or rebate at the close of a six-month period.**

The calculations in this Section g are made once for each six-month period. They are applied only after a six-month period and are used to determine whether the costs incurred by BPA to acquire AAMTA during the preceding six-month period were more or less than the LB CRAC revenues actually received by BPA during such six-month period. The calculations in this Section will be performed as soon as the necessary actual data is available after each six-month period. There are four steps involved in this determination.

- Step One: Calculate the LB CRAC revenues that were actually collected during the six-month period separately for Slice and Non-Slice sales;
- Step Two: Calculate the LB CRAC revenues that are needed to cover the AAMTA power costs incurred by BPA during the six-month period, divided between Slice and Non-Slice products based on actual LB CRAC revenues;
- Step Three: Calculate the difference between Step One and Step Two for Slice and Non-Slice products separately;
- Step Four: Calculate the change in cost of meeting AAMTA associated with using the NACA(120) and NACA(0).
- Step Five: Calculate the adjustment to the bill of each customer.

(i) Step One

$$LBCREV(S) = TREV_w/LBC(S) - TREV_w/oLBC(S)$$

$$LBCREV(NS) = TREV_w/LBC(NS) - TREV_w/oLBC(NS)$$

(ii) Step Two

$$ACTUALLBCREVREQ(S) = [NACA * (TREV_w/LBC(S)/TTREV_w/LBC)]$$

$$ACTUALLBCREVREQ(NS) = [NACA * (TREV_w/LBC(NS)/TTREV_w/LBC)]$$

(iii) Step Three

$$REVDIFF(S) = LBCREV(S) - ACTUALLBCREVREQ(S)$$

$$REVDIFF(NS) = LBCREV(NS) - ACTUALLBCREVREQ(NS)$$

(iv) Step Four

In this step, the difference in cost associated with meeting AAMTA for the six-month period between NACA(0) and NACA(120) is determined. The difference will be referred to as:

$$\text{NACDIFF} = \text{NACA}(0) - \text{NACA}(120).$$

(v) Step Five

There will be a separate line item on the bill of each customer purchasing products at rates subject to the LB CRAC reflecting a debit or a credit, and referred to as ADJUST(S) for the Slice rate and ADJUST(NS) for Non-Slice Rates.

(a) Bill Adjustment for a Slice purchaser.

$$\text{ADJUST}(S) = \{ \text{REVDIFF}(S) * [\text{CUSTREV}(S)/\text{TREV}_w/\text{LBC}(S)] \} / 6$$

(b) Bill Adjustment for Purchaser of Non-Slice products subject to the LB CRAC.

$$\text{ADJUST}(NS) = \{ [\text{REVDIFF}(NS) + \text{NACDIFF}] * [\text{CUSTREV}(NS)/\text{TREV}_w/\text{LBC}(NS)] \} / 6$$

(c) Each of these bill adjustments (ADJUST(NS)) (ADJUST(S)) will initially be added to the bill beginning the month following their finalization and shall continue for a six-month period. BPA and the purchaser may agree to a different payment schedule for any six-month period. For the first six-month period, since customers proposed two 3-month calculations, the results of the first 3-month calculation, scheduled for mid-February 2002, will be spread across 3 months, while the second 3-month adjustment, scheduled for June 2002, will be spread across six months (this assures no overlap between bill adjustments for the actual LB CRAC costs for this first six-month period).

**2. Financial-Based Cost Recovery Adjustment Clause**

The FB CRAC is a temporary, upward adjustment to posted power rates for certain Subscription sales which occurs if end-of-year Accumulated Net Revenues (ANR) in the generation function are forecasted to fall below a threshold level.

The FB CRAC applies to power customers under these firm power rate schedules: PF [Preference (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), New Resource Firm Power (NR-02), and Subscription purchases under Firm Power Products and Services (FPS). The FB CRAC does not apply to power sales under Pre-Subscription contracts to the extent prohibited by such contracts, purchases under the PF Slice Rate, the 900 aMW of financial benefits provided under the financial portion of any REP Settlement or for BPA's contractual obligations for Seasonal and Irrigation Mitigation sales, including for any eligible customer that converts from Slice to another BPA product. The FB CRAC does apply to the 1,000 aMW power sale portion of the REP Settlement, including where power sales are converted to cash payments calculated pursuant to Section 5(b) of the Residential Exchange Settlement Agreement.

a. **Formula for Calculation of the Financial-Based Cost Recovery Adjustment Clause**

By August of the fiscal year immediately prior to each fiscal year of the rate period (*i.e.*, FY 2002-2006), a forecast of that end-of-year ANR will be completed. If the ANR at the end of the forecast year falls below the FB CRAC Threshold applicable to that fiscal year, the FB CRAC will trigger, and a CRAC rate increase will go into effect beginning in October of the upcoming fiscal year.

The Revenue Amount will be determined by the following formula:

Revenue Amount is the lower of:

FB CRAC Threshold minus forecasted ANR;

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 FB CRAC is intended to generate during the period that the rate increase is effective.

Where FB CRAC Threshold is the "trigger point" for invoking a rate increase under the FB CRAC. The threshold is pre-specified for the end of FY 2001, 2002, 2003, 2004, and 2005, in Table B.



Where ANR is generation function net revenues, as accumulated since 1999, at the end of each of the FY 2001-2005. Audited Actual Accumulated Net Revenues (AANR), confirmed by BPA's independent auditing firm, will be used for FY 1999 and 2000, and any subsequent year for which they are available. Unaudited AANR will be used to the extent audited actuals are not available.

The expected value of a probabilistic forecast of ANR through the end of each fiscal year will be calculated and used to determine if the threshold has been reached, and what the Revenue Amount is. Net revenues for any given fiscal year are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Practices, with the following two exceptions. First, for purposes of determining if the FB CRAC threshold has been reached, actual and forecasted expenses will include BPA expenses associated with Energy Northwest debt service as forecasted in the WP-02 Final Studies. Second, the impact of adopting Financial Accounting Standard 133, Accounting for Derivative Instruments and Hedging Activities, will not be considered in determining if the CRAC threshold has been reached. Only generation function revenues and expenses, which is to say actual and forecasted revenues and expenses that are associated with the production, acquisition, marketing, and conservation of electric power, will be included in determinations under the FB CRAC. Accrued revenues and expenses of the transmission function are excluded. Impacts of forecasted revenues, positive or negative, from contractual true-up pursuant to the Slice Agreement shall be included in the revenue forecast when determining the FB CRAC. As part of BPA's annual audit process, BPA's independent outside auditing firm will confirm that BPA's AANR determination was consistent with applicable criteria. This confirmation will be made in accordance with additional agreed upon procedures established by BPA and its independent outside auditing firm after consultation with interested parties.

Where Maximum Planned Recovery Amount is the maximum annual amount planned to be recovered through the FB CRAC.

**Table B**

<b>End of Fiscal Year</b>	<b>FB CRAC Threshold (ANR)</b>	<b>Maximum Planned Recovery Amount (Beginning October)</b>
2001	\$ -386M	NONE
2002	\$ -408M	\$135 M
2003	\$ -265M	\$150 M
2004	\$ -299M	\$150 M
2005	\$ -299M	\$175 M

Once the Revenue Amount is determined, that amount will be converted to the FB CRAC Percentage. The FB CRAC Percentage is the percentage increase in customers' rate (not including LB CRAC) in each of the firm power rate schedules listed above. This percentage will be applied to generate the additional FB CRAC revenue.

The FB CRAC Percentage will be determined by the following formula:

$$\begin{aligned} &\text{FB CRAC Percentage} = \\ &\text{Revenue Amount} \\ &\text{Divided by} \\ &\text{FB CRAC Revenue Basis} \end{aligned}$$

For FY 2002, the FB CRAC Revenue Basis is the total generation revenue (not including LB CRAC) for the loads subject to FB CRAC for the fiscal year in which the FB CRAC implementation begins, based on the then most current revenue forecast. For FYs 2003-2006, FB CRAC Revenue Basis is the total generation revenue (not including LB CRAC) for the loads subject to FB CRAC plus Slice loads for the fiscal year in which the FB 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.

Rate increases under the FB CRAC will be due in 12-monthly payments from November (for the October billing period) through October of the following year.

**b. FB CRAC Adjustment Timing**

In August prior to the beginning of each year of the rate period, the Administrator will determine whether the expected value of the ANR forecast at the end of that current fiscal year is below the FB CRAC Threshold. If the ANR is forecasted to fall below the FB CRAC Threshold, the Administrator will propose, by the end of August, to assess a cost recovery adjustment to applicable rates for power deliveries beginning in October.

Each customer will be notified, on or about September 1st, of the percentage increase in rates due to the FB CRAC. The rates used to calculate the customers' bills for the following October through September will reflect the FB CRAC increase.

c. **FB CRAC Notification Process**

BPA shall follow the following notification procedures:

(1) **Financial Performance Status Reports**

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 ANR.

By January of each year, BPA shall post on its web site the audited AANR attributable to the generation function for the prior fiscal year ending September 30.

In May and August of each year, BPA shall post on its web site an end-of-year forecast of ANR attributable to the generation function.

(2) **Actions to mitigate the need for the FB CRAC**

If actual accumulated net revenues at the end of a fiscal year are within \$150 million of the FB CRAC threshold for the subsequent year, BPA will prepare and post on its Web site an analysis for 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 FB CRAC. BPA shall conduct a public comment period on these actions to avert or reduce a potential FB CRAC rate adjustment by the following October.

(3) **Notice of FB CRAC Trigger**

BPA shall complete and adopt a probabilistic forecast of end-of-year ANR in August of each year. BPA shall notify all customers and rate case parties by the end of August, in each of the FYs 2001-2005, if the expected value of ANR is forecasted to fall below the FB CRAC Threshold for that fiscal year and, if so, the extent to which BPA intends to adjust rates under the FB CRAC. Notification will include the audited AANR for the prior FY, the forecast of end-of-year ANR, the calculation of the Revenue Amount, and the FB 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 FB CRAC implementation process.

In early September, for any year in which the ANR is forecasted to fall below the FB CRAC Threshold, BPA staff shall conduct a public forum to explain the ANR forecast, the calculation of the Revenue Amount and the FB CRAC Percentage, and demonstrate that the FB CRAC has been implemented in accordance with the GRSPs. The forum will provide an opportunity for public comment.

On or about September 30 of any fiscal year in which the ANR is forecasted to fall below the FB CRAC Threshold, the Administrator shall provide all customers the calculation of the adjustment and the resulting rate increase (as a percentage) applicable to each rate schedule.

d. **True-up**

There will be an opportunity for trueing-up the FB CRAC Revenue Amount and each customer's portion of it, based on updated data. When audited actuals are available, in January in the year subsequent to the FB CRAC being implemented, the AANR will be compared to the ANR forecast used to implement the FB CRAC. If the forecasted amount is within \$5 million of the AANR (the tolerance), no true-up will be made. If AANR differs from the forecast by more than the tolerance, an adjustment will be made in customer bills for the second half of the year. The adjustment will be made as follows:

FB CRAC Adjustment = (difference between the originally calculated FB CRAC Revenue Amount and Revenue Amount calculated using AANR)  
divided by  
generation revenue (not including LB CRAC) for the loads subject to FB CRAC, as forecasted for power deliveries for April through September.

The resulting percentage will be used to adjust the FB CRAC Percentage applied to each customer's bills for April through September. The total amount collected, however, will not exceed the Maximum Planned Recovery Amount.

3. **Safety-Net Cost Recovery Adjustment Clause**

The SN CRAC will be available if the Administrator determines that, after implementation of the FB CRAC and any Augmentation True-Ups, either of the following conditions exist:

- BPA forecasts a 50 percent or greater probability that it will nonetheless miss its next payment to Treasury or other creditor, or
- BPA has missed a payment to Treasury or has satisfied its obligation to Treasury but has missed a payment to any other creditor.

The SN CRAC applies to power purchases under the following firm power rate schedules: PF [Preference (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 both the actual power deliveries and the 900 aMW of monetary benefits under the financial portion of any REP Settlement), New Resource Firm Power (NR-02), and purchases under Firm Power Products and Services (FPS). The SN CRAC does not apply to power purchases under Pre-Subscription contracts to the extent prohibited by such contracts, to BPA's current contractual obligations for Seasonal and Irrigation Mitigation sales including for any eligible customer that converts from Slice to another BPA product, or to purchases under the PF Slice Rate.

The SN CRAC will be an upward adjustment to posted power rates subject to the FB CRAC by modifying the FB CRAC parameters. BPA will propose changes to the FB CRAC parameters that will, to the extent market and other risk factors allow, achieve a high probability that the remainder of Treasury payments during the FY 2002-2006 rate period will be made in full. BPA's proposal could include changes to the Revenue Amount, the duration (the length of time the SN CRAC would be in place, which could be more than one year), and the timing of collection. The additional revenue to be generated by the SN CRAC will be collected through a uniform percentage increase in all rates subject to the FB CRAC and a commensurate decrease in the financial portion of the Residential Exchange Settlement.

a. **SN CRAC Notification Process**

At the time the Administrator determines that the SN CRAC has triggered, BPA will send written notification of the determination to customers that purchase power under rates subject to the FB CRAC and to interested parties. Such notification shall include the documentation used by BPA to determine that the SN CRAC has triggered, the amount of any forecast shortfall, and the time and location of a workshop on the SN CRAC.

The purpose of the SN CRAC workshop will be to discuss with customers and interested parties the cause of shortfall, and any proposed changes to the FB CRAC that will achieve a high probability that the remainder of Treasury payments during the FY 2002-2006 rate period will be made timely. In determining which proposal to include in its initial proposal in the SN CRAC Section 7(i) proceeding, BPA will give priority to prudent

cost management and other options that enhance Treasury Payment Probability while minimizing changes to the FB CRAC.

**b. SN CRAC Hearing Process**

As soon as practicable after a determination that the SN CRAC has triggered, BPA will publish a Federal Register Notice initiating an expedited hearing process to be conducted in accordance with Section 7(i) of the Northwest Power Act. The hearing shall be completed within 40 days, unless a different duration is agreed to by the parties. Upon completion of such hearing, BPA will submit the following documentation in support of a request for review and confirmation: Statements A through F from the 2002 BPA Wholesale Power Rate Adjustment Proceeding, Separate Accounting Analysis, current and revised revenue tests, the proposed revisions to the FB CRAC parameters and the administrative record compiled by BPA in the SN CRAC proceeding.

The changes to the FB CRAC parameters shall take effect 61 days from filing with FERC unless FERC orders otherwise prior to that time.

**H. Dividend Distribution Clause**

The DDC is a clause establishing criteria that the Administrator will use to decide whether funds are to be distributed to customers, and the amount that is to be distributed. The DDC enables BPA to distribute funds to eligible firm power customers and establishes the mechanism to be used to make a distribution.

The DDC applies to purchases by power customers under these firm power rate schedules subject to the FB CRAC, including: PF [Preference (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) New Resource Firm Power (NR-02), and purchases under Firm Power Products and Services (FPS) that are subject to the FB CRAC. The DDC also applies to the financial portion of the REP Settlement as described herein. The DDC does not apply to power purchases under Pre-Subscription contracts, or purchases under the Slice Rate.

**1. Formula for the Calculation of the Dividend Distribution Amount**

The DDC, for FY 2003-2006, will be implemented if audited AANR for the end of any of the FY 2002-2005 are above the DDC Threshold value.

AANR are generation function net revenues, as accumulated since 1999, at the end of each of the FY 2002-2005. Net revenues are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Practices, with the

following exceptions. For purposes of determining if the DDC threshold has been reached, actual and forecasted expenses will include BPA expenses associated with Energy Northwest debt service as forecasted in the Final Studies from the 2002 Final Power Rate Proposal, WP-02-FS, May 2000. The impact of adopting Financial Accounting Standard 133, Accounting for Derivative Instruments and Hedging Activities, will not be considered in determining if the CRAC threshold has been reached. 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. As part of BPA's annual audit process, BPA's independent outside auditing firm will confirm that BPA's AANR determination was consistent with applicable criteria. This confirmation will be made in accordance with additional agreed upon procedures established by BPA and its independent outside auditing firm after consultation with interested parties.

DDC Threshold is the level of AANR that must be realized before a distribution is made as required by this section. The DDC Threshold is \$993 million for the end of FY 2002, \$735 million for the end of FY 2003, and \$401 million for the end of FYs 2004 and 2005.

The DDC threshold for any fiscal year will be adjusted upward by the following:

- a. In the event that there has been a power system emergency (as defined in "FCRPS Protocols for Emergency Operation In Response to Generation or Transmission Emergencies" dated September 22, 2000, or replacement protocols) during the fiscal year; and BPA has agreed to provide additional funding to mitigate the impact of the emergency operations on fish and wildlife, any of the additional emergency-related fish and wildlife funding which BPA has not spent during that fiscal year will be added to the threshold amount for that year; and/or
- b. In the event that BPA fish and wildlife operations and maintenance ("direct program") costs previously budgeted for expenditure in that fiscal year but were not spent, and for which a need continues, will be added to the threshold amount for that year.

DDC Amount is the aggregate amount in excess of the DDC Threshold that is available to be distributed to customers. The DDC Amount may be equal to zero and will be determined by the following formula:

$$\text{DDC Amount} = \text{AANR} - \text{DDC Threshold, as adjusted}$$

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.

The Customer DDC Amount, which is the DDC Amount after reduction by the \$15 million as described in the preceding paragraph, will be returned to power customers. Any such amounts will be returned to customers in proportion to the DDC Customer Revenue Amount, which is the revenue BPA received from each customer under rates subject to the DDC since the beginning of the rate period, or since the last DDC, whichever is later. A customer's DDC Customer Revenue Amount excludes Slice revenues, and includes all Non-Slice CRAC revenues. The IOU financial benefit is included as revenue based on the product of each customer's share of 900 aMW and the sum of the RL-02 rate and the amount of any CRAC applied to power deliveries under such rate.

DDC Percentage =  
Each customer's DDC Customer Revenue Amount  
divided by  
sum of all Customer Revenue Amounts

Each covered power customer will receive a rebate equal to the Power Customer DDC Percentage times the Customer DDC Amount. One-twelfth of each customer's share of the Customer DDC Amount will be credited to customers, on bills for deliveries beginning April 1, and for any FY 2003-2005, remain in effect for 12 months, *i.e.*, through March 30 of the following year. In the last year of the rate period (FY 2006), one-sixth of each customer's share of the Customer DDC Amount will be credited to customers, on bills for deliveries beginning April 1, through September 30, 2006.

## **2. Determination of a Distribution**

In January of each year of the rate period (FY 2003-2006), the Administrator will determine whether the AANR exceeds the DDC Threshold. If the AANR exceeds the DDC Threshold, customers and rate case parties will be so notified. By March 1, the Administrator will provide calculations of any proposed distribution of Customer DDC Amount. The Administrator will issue a final decision on the proposal on or about April 15.



### **3. 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 FY ending September 30.

#### **b. Notice of DDC Trigger**

On or about January 15, in each of the FY 2003-2006, 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.)

- (1) On or about February 15, of any of the FY 2003-2006 in which the AANR exceeds the DDC Threshold, the Administrator will notify all power customers and rate case parties. Notification will include the AANR for the prior fiscal year, the DDC Amount, the calculation of any adjustments to the threshold, calculation of the DDC Amount, the sum of Customer Revenue Amounts, and each customer's proposed DDC 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 DDC implementation process.

Prior to March 15, BPA will conduct a public review and comment process on the proposal.

- (2) On or about April 15, of any of the FY 2003-2006 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.

**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 FY 2002-2006 period. This forecast is used in calculating the cash component of the settlements of the REP with regional IOUs as described in BPA’s Power Subscription Strategy. The Five-Year Flat Block Price Forecast for this purpose is \$38 per MWh.

**S. Slice True-Up Adjustment**

Each year BPA will calculate the financial true-up for the previous fiscal year, in accordance with the provisions of the Slice Agreement. This contractual true-up will be completed each year regardless of whether the LB CRAC has increased or decreased the PF Slice Rate. See the Slice Product Costing and True-Up Table (Table D). The revenues from this contractual true-up will not be included in any calculation, or application, of the LB CRAC. In addition, adjustments to the Slice rate contained in Administrator’s Record of Decision in 2002 Final Power Rate Proposal, WP-02-A-02, May 2000, that occur in accordance with the methodology in section F of these GRSPs are separate, and are applied separately from, the financial true-up under the Slice Agreement referred to in this paragraph.

**X. Slice Portion of IOU Settlement**

Each monthly Slice bill will include a line item to account for the proposed increment in the IOU cash settlement above the May Proposal. The revenues from this section will not be included in any calculation of the LB CRAC.

The monthly adjustment per one-percent Slice is proposed to be:

[Incremental amount of IOU Settlement costs in the Supplemental Rate Case  
ROD/12/100] = \$ per month per one-percent Slice.

The incremental amount of IOU Settlement costs = [(\$38.00/MWh-\$28.10/MWh) x  
(900 aMW x 8,760 hours)]/12/100  
= \$78,051,600/12/100  
= \$65,043 per month per one-percent Slice

*Revisions to:*

**SECTION III: DEFINITIONS**

**B. Definition of Rate Schedule Terms**

24. Inventory Augmentation (or Inventory Solution)

BPA's action to supplement the capability of the Federal System Resources, as a result of BPA's Subscription process.

UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION

United States Department of Energy )  
Bonneville Power Administration ) Docket No. EF00-2012-001  
Proposed 2002 Wholesale Power Rates )

**BONNEVILLE POWER ADMINISTRATION'S ERRATA CORRECTIONS  
TO SUPPLEMENTAL WHOLESALE POWER RATE PROPOSAL  
GENERAL RATE SCHEDULE PROVISIONS**

Pursuant to the Commission's Regulations for Federal Power Marketing Administrations, 18 C.F.R. § 300.10(h), Bonneville Power Administration (BPA) hereby respectfully files limited errata corrections to the General Rate Schedule Provisions (GRSP's) included in BPA's 2002 Supplemental Wholesale Power Rate Proposal. The errata corrections are described in detail below.

On June 29, 2001, pursuant to section 7(a)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. §839e(a)(2), BPA filed a Supplemental Wholesale Power Rate Proposal with the Commission. *U.S. Department of Energy, Bonneville Power Administration*, Docket No. EF00-2012-001. BPA requested approval effective October 1, 2001, through September 30, 2006, for its proposed rates. BPA also requested approval effective October 1, 2001, through September 30, 2006, for its proposed 2002 GRSP's, which apply to BPA's proposed 2002 wholesale power rates.

BPA recently identified a number of errata in BPA's 2002 Supplemental Wholesale Power Rate Proposal GRSP's. These errata concern the Load Based Cost Recovery Adjustment Clause (LB CRAC). The errata corrections follow:

1. In GRSP Section II.F.1.b.(22), change “(LOAD(S)) “*Slice Load Subject to LB CRAC*” means loads that are served by BPA at the Slice rate. LOAD(S) is initially 2,000aMW but will be adjusted to reflect contracted Slice loads prior to October 1, 2001.” to “(LOAD(S)) “**Slice Load Subject to LB CRAC**” means loads that are served by BPA at the Slice rate. LOAD(S) is to be (1,600/7,070)\*100.”

This correction is necessary to reflect updated contracted Slice loads prior to October 1, 2001, and to clarify the determination of “LOAD(S).”

2. In GRSP Section II.F.1.d.(4), change “SALESMAYAUGF = Minimum[AAMTF, 1,745 aMW – [(forecasted DSI load/1486)\*450].” to “SALESMAYAUGF = Minimum[AAMTF, (1,745 aMW – [(forecasted DSI load reduction/1486)\*450]).”

BPA inadvertently omitted the word “reduction” from the previous GRSP language. This correction is necessary to clarify that “forecasted DSI load” should be “forecasted DSI load reduction.”

3. In GRSP Section II.F.1.f.(4), change “SALESMAYAUGA = Minimum[AAMTA, 1,745 aMW – [(actual DSI load/1486)\*450].” to “SALESMAYAUGA = Minimum[AAMTA, (1,745 aMW – [(actual DSI load reduction/1486)\*450]).”

BPA inadvertently omitted the word “reduction” from the previous GRSP language. This correction is necessary to clarify that “actual DSI load” should be “actual DSI load reduction.”

4. In GRSP Section II.F.1.d.(6), change “REVw/oLBC(NS) = [RATE(NS) \* LOAD(NS) \* Hours in month] – LDD(NS) – C&R(NS) – ((energy quantity of rate mitigation deals tied to LB CRAC \* \$19.26/MWh))” to “REVw/oLBC(NS) = [RATE(NS) \* LOAD(NS) \* Hours in month] – LDD(NS) – C&R(NS) – [the energy quantity of rate mitigation deals tied to LB CRAC from the Slice contracts \* \$27.5/MWh] – [the energy quantities of rate mitigation deals tied to LB CRAC from non-Slice contracts \* \$19.26/MWh].”

This correction is necessary to reflect the fact that some rate mitigation contracts are tied to a customer’s Slice percentage and some are tied to a customer’s block amount. Because the REVw/oLBC calculation is the sum of REVw/oLBC(S) and REVw/oLBC(NS), BPA has subtracted “[the energy quantity of rate mitigation deals tied to LB CRAC from the Slice contracts \* \$27.5/MWh]” from “REVw/oLBC(NS).” BPA could have subtracted this same amount from REVw/oLBC(S), and there is no change in the calculations due to its subtraction from REVw/oLBC(NS) .

Wherefore, BPA respectfully files the above-noted errata corrections to BPA’s

Supplemental Wholesale Power Rate Proposal GRSP’s in *U.S. Department of Energy,*

*Bonneville Power Administration,* Docket No. EF00-2012-001. In the event any waiver of the

Commission's regulations is necessary for this filing, BPA hereby requests such waiver for the reasons noted above.

DATED this 18th day of September 2001.

RESPECTFULLY SUBMITTED,

**/s/ Kurt R. Casad**

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KURT R. CASAD  
Attorney for the  
Bonneville Power Administration  
905 N.E. 11<sup>th</sup> Avenue  
Portland, Oregon 97232  
Phone: (503) 230-4024

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

United States Department of Energy                    )  
Bonneville Power Administration                    )                    Docket No. EF00-2012-001  
Proposed 2002 Wholesale Power Rates            )

**BONNEVILLE POWER ADMINISTRATION’S SECOND ERRATUM CORRECTION  
TO THE SUPPLEMENTAL WHOLESALE POWER RATE PROPOSAL  
GENERAL RATE SCHEDULE PROVISIONS**

Pursuant to the Commission's Regulations for Federal Power Marketing Administrations, 18 C.F.R. § 300.10(h), Bonneville Power Administration (BPA) hereby respectfully files an erratum correction to an introductory paragraph of the General Rate Schedule Provisions (GRSPs) included in BPA’s 2002 Final Supplemental Wholesale Power Rate Proposal (Supplemental Proposal). The erratum correction is as follows: In BPA’s GRSPs, *2002 Supplemental Power Rate Proposal, Administrator’s Record of Decision*, WP-02-A-09, Appendix, Page 1, Section A, ¶ 3, delete the words “except for the FPS-96 rate schedule” in the first sentence. This correction is necessary in order to rectify an inadvertent error that occurred during the final drafting and printing of BPA’s Supplemental Proposal GRSPs.

BPA’s Firm Power Products and Services (FPS-96) rate schedule is available for sales of surplus firm power. The Commission approved the FPS-96 rate schedule on a final basis for a 10-year period commencing October 1, 1996, and expiring September 30, 2006. *United States Department of Energy - Bonneville Power Admin.*, 80 FERC ¶ 61, 118 (1997). The FPS-96 rate schedule contains the following sentence: “Sales under the FPS-96 rate schedule are subject to BPA’s GRSPs.” *See 1996 Final Power Rate Proposal, Administrator’s Record of Decision*,

WP-96-A-02, Appendix 1, at 63, Section I. While the FPS-96 rate schedule was approved for a 10-year term, the 1996 GRSPs were approved for a five-year term from October 1, 1996, through September 30, 2001. *United States Department of Energy - Bonneville Power Admin.*, 80 FERC ¶ 61, 118 (1997). BPA's 1996 GRSPs expired on September 30, 2001. *Id.* BPA's proposed 2002 power rate adjustment currently pending before the Commission does not change the FPS-96 rate schedule, but does change the GRSPs. On September 28, 2001, the Commission granted interim approval of BPA's 2002 wholesale power rates, including the successor 2002 GRSPs, effective from October 1, 2001, through September 30, 2006. *United States Department of Energy - Bonneville Power Admin.*, 96 FERC ¶ 61,360 (2001). The successor 2002 GRSPs apply to the remaining five years of the FPS-96 rate schedule. *See 2002 Final Power Rate Proposal, Administrator's Record of Decision*, WP-02-A-02, Appendix 1, at 75, Section I.B.

When BPA commenced its 2002 wholesale power rate adjustment proceeding in 1999, BPA's Federal Register Notice stated that BPA's successor 2002 GRSPs superseded BPA's 1996 GRSPs to the extent stated in the Availability section of each rate schedule. *See Bonneville Power Administration's 2002 Proposed Wholesale Power Rate Adjustment, Public Hearing, and Opportunities for Public Review and Comment*, 64 Fed. Reg. 44318 (1999). The Availability section of each rate schedule governs the application of the GRSPs to that rate schedule. The Availability section of the FPS-96 rate schedule still contains the above-quoted sentence requiring application of BPA's GRSPs, now the successor 2002 GRSPs, to sales under the FPS-96 rate schedule.<sup>1</sup>

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<sup>1</sup> BPA recently modified the FPS-96 rate schedule. That modification was approved by the Commission on a final basis and did not involve a change in the application of the GRSPs to the FPS-96 rate schedule. *See U.S. Department of Energy – Bonneville Power Administration*, 95 FERC ¶ 61,082 (2001).



In addition, when BPA printed its proposed 2002 GRSPs at the conclusion of BPA's initial phase of its 2002 wholesale power rate adjustment proceeding (the May Proposal), the introductory paragraphs to the GRSPs reiterated that BPA's successor 2002 GRSPs superseded BPA's 1996 GRSPs to the extent stated in the Availability section of each rate schedule. *See 2002 Final Power Rate Proposal, Administrator's Record of Decision, WP-96-A-02, Appendix 1, at 75, Section I.B.* BPA's May Proposal GRSPs did not include any statement exempting the FPS-96 rate schedule from the application of the GRSPs. *Id.* Furthermore, in BPA's supplemental rate proceeding, BPA and the parties did not address any changes to the GRSPs, except for changes related to the Cost Recovery Adjustment Clauses. BPA has therefore consistently demonstrated its intent to apply the GRSPs to all rate schedules, except for the inadvertent statement noted previously. There was, however, no basis in the record on which BPA could have exempted the FPS-96 rate from the GRSPs in BPA's Supplemental Proposal.

In summary, when preparing BPA's 2002 Supplemental Proposal GRSPs, BPA inadvertently and incorrectly included a phrase that exempted the FPS-96 rate schedule from the GRSPs. This phrase does not comport with the Availability section of the FPS-96 rate schedule as approved by the Commission, does not comport with the Commission's orders limiting BPA's GRSPs to five-year terms, is inconsistent with BPA's intent, and lacks support in the administrative record.

Wherefore, BPA respectfully files the above-noted erratum correction to BPA's Final Supplemental Wholesale Power Rate Proposal GRSPs in *U.S. Department of Energy, Bonneville Power Administration*, Docket No. EF00-2012-001.

DATED this 1st day of November 2001.

RESPECTFULLY SUBMITTED,

**/s/ Kurt R. Casad**

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KURT R. CASAD  
Attorney for the  
Bonneville Power Administration  
905 N.E. 11<sup>th</sup> Avenue  
Portland, Oregon 97232  
Phone: (503) 230-4024

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

United States Department of Energy	)	
Bonneville Power Administration	)	Docket Nos. EF00-2012-000,
Proposed 2002 Wholesale Power Rates	)	EF00-2012-001

**BONNEVILLE POWER ADMINISTRATION'S ERRATUM CORRECTION  
TO BPA'S 2002 FINAL POWER RATE PROPOSAL  
GENERAL RATE SCHEDULE PROVISIONS**

Pursuant to the Commission's Regulations for Federal Power Marketing Administrations, 18 C.F.R. § 300.10(h), Bonneville Power Administration (BPA) hereby respectfully files an erratum correction to the General Rate Schedule Provisions (GRSPs) included in BPA's 2002 Final Power Rate Proposal (May Proposal). The erratum correction is as follows:

In BPA's GRSPs, *2002 Final Power Rate Proposal, Administrator's Record of Decision*, WP-02-A-02, Appendix 1, Section III.A.13 (page 116), the last sentence reads: "PF is power where BPA agrees to provide operating reserves in accordance with the standards established by the NERC, WSCC, and NWPP." Please delete the words "BPA agrees to provide" and replace them with "BPA's TBL provides".

This correction is necessary in order to clarify that BPA's operating reserves for PF power sales are provided by BPA's Transmission Business Line (TBL), not BPA generally or BPA's Power Business Line.

Wherefore, BPA respectfully files the above-noted erratum correction to BPA's GRSPs in BPA's *Final Power Rate Proposal, Administrator's Record of Decision*, WP-02-A-02,

Appendix 1, Section III.A.13, which is before the Commission in *U.S. Department of Energy, Bonneville Power Administration*, Docket No. EF00-2012-000.

DATED this 28th day of November 2001.

RESPECTFULLY SUBMITTED,

**/s/ Kurt R. Casad**

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KURT R. CASAD  
Attorney for the  
Bonneville Power Administration  
905 N.E. 11<sup>th</sup> Avenue  
Portland, Oregon 97232  
Phone: (503) 230-4024