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

2010 Wholesale Power and Transmission Rate Adjustment Proceeding (BPA-10)

ADMINISTRATOR'S FINAL RECORD OF DECISION

July 2009

WP-10-A-02
TR-10-A-02

BONNEVILLE
POWER ADMINISTRATION

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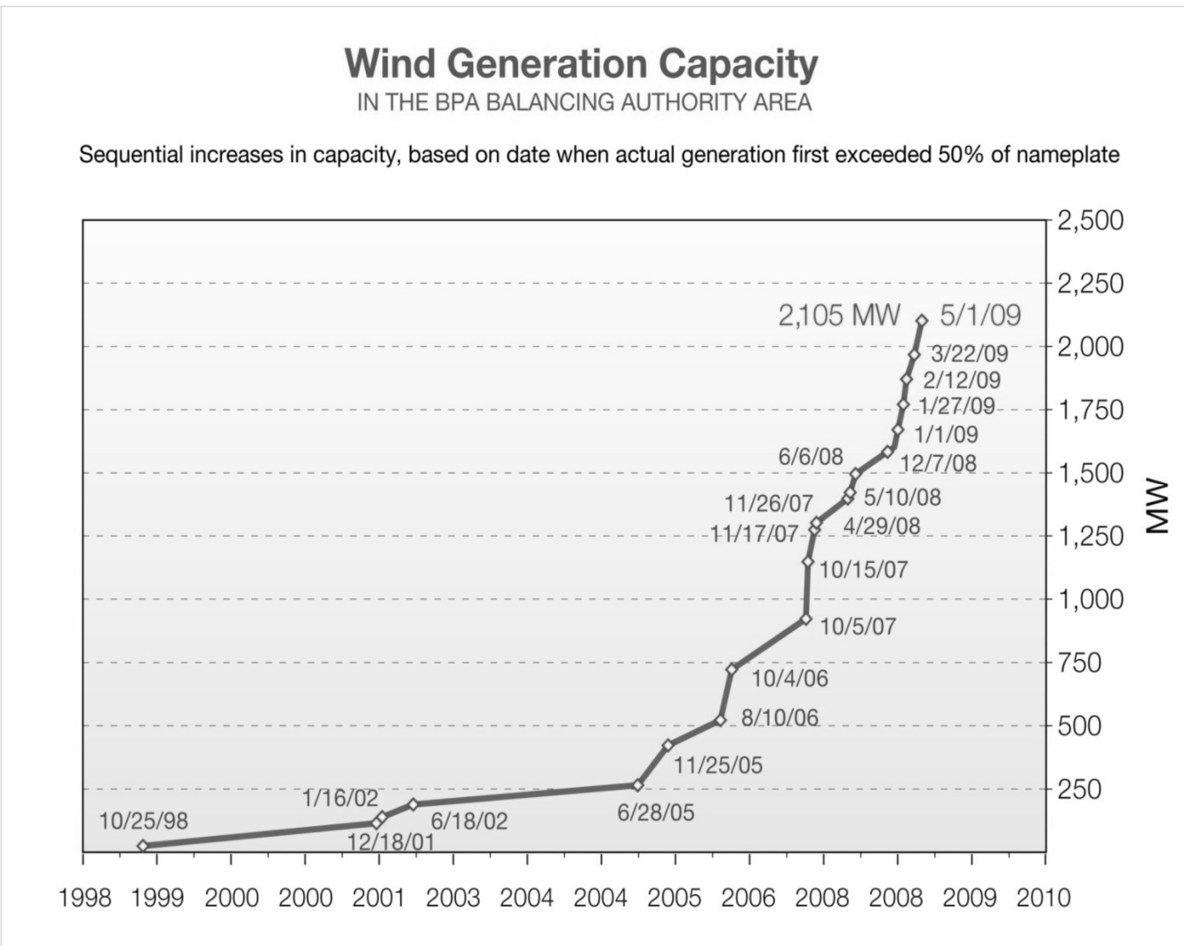
ADMINISTRATOR'S PREFACE

TO THE BPA-10 RECORD OF DECISION

One of the most difficult and important issues in this rate case has been how to address identifying and recovering the costs of integrating wind into the Bonneville Power Administration's transmission grid. There has been an explosion of wind power on the BPA system, especially since 2005 (see graph). While this is a development to be cheered and further encouraged, we cannot responsibly ignore the fact that the large amount of wind on our system has also led to operational challenges, including risks to reliability, substantial costs, and the need to appropriately allocate these costs. These challenges have been exacerbated by the fact that nearly 80 percent of the wind on the BPA system is exported to other balancing authority areas. The failure to solve these problems threatens to limit the amount of wind power that can be interconnected with the BPA transmission system.



This rate case represents one element of BPA's response to resolving these challenges. This response has generally fallen into the following categories: (1) ensuring system reliability and meeting non-power constraints of the hydro system, (2) sending appropriate price signals as to the cost of providing these services, and (3) providing wind operators choice in terms of supplier of wind integration services.

The Challenge

Our field experience with wind power has created greater clarity around a substantial concern. Wind resources on the BPA system are producing large ramp events—that is, wind output moving both up and down—over short periods of time. In general, these changes in output had not been predicted in hourly schedules submitted by wind operators, even when the ramp was occurring over multiple hours. Transmission providers must balance loads and resources in real time to ensure reliability. In order to protect reliability with increasing amounts of wind on the system, BPA must hold a larger amount of generating reserves. This means, in effect, reserving parts of the Federal hydrosystem to be available to back up wind in case unscheduled wind ramps occur unexpectedly. Historically BPA has used the Federal hydrosystem to provide reserves for all variability that occurs within its transmission network, but wind has presented unprecedented variability.

By last summer, the size of the wind fleet and the unscheduled ramps led BPA to become concerned that it was fast approaching the limits of what its system could physically provide. Yet forecasts call for substantial increases in wind power within the BPA network. Moreover, BPA had no clear mechanism to control wind power output if reliability was at risk. The data indicated that even minimal efforts on the part of wind operators to improve scheduling practices would reduce BPA's need to hold reserves and reduce the risk that reserves would be insufficient, resulting in a reliability event. For example, analysis indicated that if wind operators just used the previous hour's actual results to forecast the next hour's schedule, there would be a substantial improvement in scheduling accuracy.

Last summer BPA began describing this problem in more detail and took action. It was our belief that if we did not take action, we were at risk of running out of reserves and having a wind-related reliability event that would negatively impact the reputation of wind power and impair the development of wind power regionally and possibly nationally. In addition, the finite amount of reserves from the Federal hydrosystem could become overtaxed, leading to difficult choices regarding the further interconnection of new wind resources.

Solutions

1) The Failsafe Protection

Our initial efforts focused on establishing the ability for BPA to reduce wind output that is operating outside its self-submitted schedule so that it would meet its schedule if BPA is running out of reserves. Through an extensive public process, procedures were developed to refine the process to require wind operators to reduce output when over-generating and to reduce the projects' impact on BPA's system when under-generating by curtailing schedules if BPA is running short on reserves. Conceptually, this work is complete and is now being turned into operating procedures that BPA dispatchers will implement through a standing order called Dispatcher Standing Order (DSO) 216.

2) Pricing – Rates and Penalties

The second initiative has been to establish appropriate pricing for providing reserves. In 2009, BPA established for the first time a rate for providing integration services for wind operators. That rate was established in a non-precedential settlement and was recognized as not covering all the costs of providing balancing services. While it was good for getting started, more work was needed. For example, the rate assumed no average scheduling inaccuracies across the hour, because we did not have the means at the time to estimate the size of the issue.

The problem of scheduling inaccuracy has been exacerbated by BPA policy. Starting in 2002, BPA exempted wind operators from what is called Band 3 Generation Imbalance penalties targeted at scheduling inaccuracies. This exemption was created on the basis of wind being a variable resource not under the control of the operator and that the existing imbalance penalties were designed to stop generation operators who were seeking to take advantage of market prices through providing knowingly inaccurate schedules. Wind was also a relatively small resource on our system, so the cost of scheduling inaccuracies was modest. Subsequently, BPA's practices were adopted by the Federal Energy Regulatory Commission. But as wind has grown on our system, it has become clear that the lenient policy with little cost to scheduling inaccuracy has led, not surprisingly, to rather indiscriminate use of balancing services even when within the control of wind operators. The policies we are putting in place have already begun to alter this behavior.

In this rate case BPA has performed extensive analysis to define the amount of reserves necessary for BPA to support wind generators, assuming various levels of scheduling accuracy by the wind fleet. Substantial work has gone into defining the costs incurred by BPA for providing these reserves. BPA is also proposing a new penalty for persistent scheduling inaccuracies. These efforts are designed to send appropriate price signals that will ensure that BPA reserves are used efficiently to support wind on the BPA system and limit the potential for a wind-related reliability event. We believe these actions are critical to ensuring further renewable resource development on the BPA system and ultimately to promoting wind power development regionally and nationally.

Using the traditional measurement of installed capacity to peak balancing authority load, BPA already has the highest concentration of wind power on its system of any U.S. balancing authority (approximately 20 percent today). Planned new interconnections suggest this number could approach 40 percent within this rate period. Establishing efficient means to provide adequate reserves while avoiding reliability problems will provide evidence that it is physically possible to accommodate substantial amounts of wind on a transmission provider's system.

Our experience so far is that the combination of proposed operational DSO 216 and pricing mechanisms is effective at dramatically improving scheduling accuracy. Prior to these actions, the wind fleet on the BPA system was operating at approximately two-hour persistence scheduling accuracy. Just in the last nine months, this has improved to one-hour persistence overall, with some operators approaching 30-minute persistence. Wind operators are investing in meteorologists and 24x7 scheduling operations in order to better their scheduling accuracy.

These changes make a substantial difference in the amount of reserves BPA needs to provide. Our analysis indicates the difference between a two-hour vs. 30-minute presumed persistence schedule is approximately 1,000 MW of combined inc (up) and dec (down) reserves.

The substantial improvement in scheduling accuracy that wind operators have accomplished in the last nine months has had two results in this rate case. First, none of the parties is arguing for the historical level of scheduling accuracy; rather, the range of requests is between 30- and 60-minute persistence. At the beginning of this case, we proposed an increase from $.68/kW/month to $2.72/kW/month. In the Draft ROD, the increase was reduced substantially, based on 45-minute persistence scheduling accuracy, and most of this reduction was due to estimates of improved scheduling accuracy and associated reductions in the need for reserves. Second, moving away from two-hour persistence allows BPA to carry substantially fewer reserves and, therefore, not have to confront the issue of whether new sources of balancing reserves must be acquired. As difficult as the issues have been in this rate case, it would have been much worse if we projected a need for purchasing and allocating the costs for new balancing resources that are likely to be substantially higher cost than using the existing BPA system.

A word of warning in this regard. It is possible the conclusion that new balancing resources are not needed could be altered if substantial new constraints are placed on the operation of the existing system, such as new fish protection measures. At this point we are not forecasting such a change nor including estimates in the rate case.

Quality of Service vs. Rate Tradeoff

The pricing for the Wind Balancing Service in the Draft ROD was based on 45-minute persistence scheduling, but going to a 30-minute persistence scheduling assumption was still under consideration. Concomitant with this change, parties were put on clear notice that it is their responsibility to live up to their promises of improved accuracy, and that a consequence of their failure would be increased generation reductions and schedule curtailments under DSO 216, because BPA will have set aside fewer reserves. Essentially this means there is a quality of service vs. rate tradeoff presented to parties to this case. Higher reserves means fewer curtailments but a higher rate, and vice versa. That was a tradeoff clearly communicated to parties during oral argument, and it was restated in the Draft ROD. To better ensure there was a deep understanding of the quality of service vs. rate tradeoff, a public workshop was held after the release of the Draft ROD to quantify the rate/curtailment tradeoff before parties made their choices in their Briefs on Exceptions.

The vast majority of wind operators expressed the view that they would prefer a lower rate and were prepared to accept the associated lower quality of service. Accordingly, BPA will set the rate based on 30-minute persistence and will operate its system to the same level of reserves. BPA will also post the amount of reserves it is carrying on a regular basis to provide transparency to those who are worried BPA will offer a low rate but carry a higher amount of reserves.

Calculating the Rate

There are substantial differences between parties in this case regarding how to calculate reserve needs and how to allocate costs. The state of the art, while substantially improved over the course of the last year, for both these issues is still relatively nascent. Decisions made here are made on the best available information, but we would expect the data and methodologies to continue to evolve substantially over time.

For reserves, we are still learning about how wind actually operates on our system and, in particular, are challenged with how to forecast the diversity of wind ramps for a fleet that continues to expand rapidly. Fundamentally though, at least for the near term associated with this rate case, it appears that most of the wind on the BPA system is going to be located just east of the Columbia Gorge, suggesting relatively little diversity of ramp rates between projects.

With respect to cost, BPA is proposing to base costs on a combination of embedded costs and variable costs, which recover the efficiency losses associated with providing reserves for wind generation. Methodologically, the approach is based on the costs placed on the BPA system and avoids opportunity cost pricing. Fundamentally, it is important to understand that BPA is charging only for the generating projects that are primarily providing reserve services for wind, which are some of the lowest-cost resources on the BPA system (such as Grand Coulee). BPA is not charging wind operators for all the costs of operating and maintaining the BPA system, including, for example, costs of the operating and terminated nuclear plants.

Penalties for Persistent Inaccurate Scheduling

As noted earlier, BPA exempted wind generators from an element of the scheduling accuracy penalty in 2002. BPA's thinking has evolved on the need to incent wind generators to schedule accurately. BPA is proposing to adopt a persistent deviation penalty charge that defines persistent deviations and establishes clear and measureable criteria. We continue to recognize that wind operators have difficulty predicting wind output from hour to hour. But, by not enforcing scheduling inaccuracy penalties, it appears we have encouraged a lack of effort on the part of wind operators to schedule accurately when possible. Many, but not all, in the wind community have taken seriously their responsibility to protect the reliability of the bulk power system. The persistent deviation penalty restores the 125 percent charge and provides wind operators up to two hours and 40 minutes to understand that a substantial wind ramp is happening and to correct their schedules when they are consistently wrong for four or more consecutive hours in the same direction. BPA is paying for the installation of 16 wind anemometers to provide data to wind operators at five-minute intervals. We believe that in almost all cases wind operators should be able to identify a wind ramp within this timeframe. In case a wind operator has made substantial effort to address this problem but is still unable to schedule accurately, he or she can petition for a waiver from the penalty.

Creating Customer Choice

Currently, wind operators are limited to receiving balancing services from BPA. As the need for wind integration services has expanded and BPA has had to establish operational and rate requirements, requests for the ability to obtain integration services from alternative integration service providers has increased. We are taking actions outside this rate case to create options for wind power operators to obtain access to alternative wind integration services. There are a variety of ways of accomplishing this, all of which require substantial system upgrades to maintain reliability. BPA has committed to developing these options based on priorities that have been established through a public process with regional stakeholders. We expect the first of these options to be available in about a year.

BPA is establishing a wind rate design under which BPA will unbundle the components and post the rate associated with each individual component to wind balancing service (i.e., regulation, following, and imbalance). The unbundled rates will allow a party that wishes to self-supply one or more components to wind balancing service, consistent with

BPA's business practices and reliability requirements, to receive a comparable credit. BPA also proposes to provide an exemption, for up to 90 days, to this rate for new generation resources undergoing testing before commercial operation.

Small Wind Generators

BPA recognizes that while small wind generators (20 MW or less) contribute to the reserve needs of the balancing authority and receive wind integration service, they often are not parties to BPA's rate cases and may not have had sufficient time to evaluate and adjust to BPA's wind integration rate proposal. Therefore, BPA will exempt small wind generators from the wind integration rate for the first year of the two-year rate period. This exemption will provide the opportunity for a small wind generator that is selling its output to a purchaser in another balancing authority the time to arrange telemetering into that balancing authority area.

Conclusion

BPA takes seriously its role to promote renewable resource development, so seriously that BPA has the highest concentration of wind on its system of any balancing authority in the country. We are forecasting a near doubling of wind on the BPA system in the next two years. We are leading the country and, as such, are having to deal with issues that others have not yet encountered. We believe we can continue to lead the country in wind power development but to do so must address how reliability can be maintained in an efficient and effective manner. We believe with these actions we can move from a system that has 20 percent peak wind-to-peak load to a system that is approaching 40 percent peak wind-to-peak load over the next two years. That will be a remarkable achievement.

Finally, while BPA believes that the wind integration portion of this rate case is moving toward a solid and positive conclusion, and has thus far been correctly decided based on the record, BPA also acknowledges that a great deal of new ground was broken in this case and that new facts and issues could arise before the next case. Accordingly, BPA will be open to different approaches to wind integration rate issues in the next rate case.

There were a few other difficult issues in this rate case that deserve mention:

1. Level of the preference rate – Substantial collaboration with customers and stakeholders went into keeping the preference rate as low as possible given the economic conditions the region is experiencing. We appreciate the effort put forth by customers and stakeholders to understand and work with us. We have managed to find creative means to address our forecast net revenue losses this year due to low water and the poor economy. A rate increase could not be avoided, though, due primarily to increases in the cost of operating the Columbia

Generating Station nuclear plant and enhancing salmon protection. A key uncertainty going forward is whether our salmon protection measures are deemed adequate under the law. Based on what we know, we believe we are at a point where our rates are as low as possible, consistent with our responsibilities to operate consistent with sound business principles.

I would note that some parties urged substantial additional cost cuts without identifying where the cuts would come from. I do not believe that making further undistributed reductions would be responsible or consistent with our commitment to cost recovery and timely repayment of the Federal investment. In addition, I have an increasing concern over requests from customers to solve inter-customer equity issues with administratively complex and costly solutions and then seeking cuts in BPA administrative costs. In the future, when dealing with inter-customer equity issues, BPA will attempt to provide a better sense of the added administrative costs involved; incrementally these may seem small, but cumulatively they add up.

2. Benefits for investor-owned-utilities' residential and small farm customers – Once again, this rate case has had to deal with substantial issues associated with the Residential Exchange Program. Once again, we strongly encourage the parties to this case and ongoing litigation to overcome differences and find common ground to resolve this issue for the benefit of the region. In particular, we encourage groups to come together even if it represents less than unanimous regional agreement.

3. Direct service industries – In the midst of this case, one aluminum company proposed a variable rate mechanism, while another provided a 60-day notice that its operations will be suspended. These actions come on top of a Ninth Circuit decision from last December that provides guidance about under what conditions the law allows us to provide service to the DSIs. We continue to want to find ways to provide service, consistent with the law, that provides a net benefit to the region. We have rejected a quick adoption of a variable rate in this case because we did not believe it could be accomplished in a manner that allows adequate public input and analysis. This should not be viewed as a rejection of working with the companies. We are currently conducting a public process looking at contractual options and remain open to the concept of a long-term variable rate that could be implemented at a later point.

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COMMONLY USED ACRONYMS

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

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

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

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

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

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PARTY ABBREVIATIONS
AND JOINT PARTY DESIGNATION CODES

Alcoa	Alcoa, Inc.
APAC	Association of Public Agency Customers
Avista	Avista Corporation
Benton	Benton County Public Utility District No. 1
BPA-PS	Bonneville Power Administration – Power Services
Canby	Canby Utility
CUB	Citizens' Utility Board of Oregon
Seattle or SCL	City of Seattle - Seattle City Light
Tacoma	City of Tacoma/Tacoma Power
Clatskanie	Clatskanie People's Utility District
CFAC	Columbia Falls Aluminum Company
Constellation	Constellation Energy
Cowlitz	Cowlitz County Public Utility District No. 1
EWEB	Eugene Water & Electricity Board
Franklin	Franklin County Public Utility District No. 1
Grant	Grant County Public Utility District No. 1
Iberdrola	Iberdrola Renewables, Inc.
Idaho Falls	Idaho Falls Power
IPC	Idaho Power Company
Idaho PUC or IPUC	Idaho Public Utilities Commission
ICNU	Industrial Customers of Northwest Utilities
Klickitat	Klickitat County Public Utility District No. 1
LADWP	Los Angeles Department of Water and Power
MSR	M-S-R Public Power Agency
NRU	Northwest Requirements Utilities
NWG	Northwest Wind Group
Okanogan	Okanogan County Public Utility District No. 1
ODOE	Oregon Department of Energy
PNGC	Pacific Northwest Generating Cooperative
Pacificorp	Pacificorp
Pend Oreille	Pend Oreille County Public Utility District No. 1
Port Townsend	Port Townsend Paper Company
PGE	Portland General Electric
Powerex	Powerex Corp.
PGP	Public Generating Pool
PPC	Public Power Council
OPUC	Public Utility Commission of Oregon
PSE	Puget Sound Energy
Snohomish	Snohomish County Public Utility District No. 1
Tillamook	Tillamook People's Utility District

WUTC	Washington Utilities and Transportation Commission
WMG&T	Western Montana Electric Generating and Transmission Cooperative
WPAG	Western Public Agencies Group

Joint Party 1 (JP1) comprises:
Avista
Idaho Power
PacifiCorp
Portland General Electric
Puget Sound

Joint Party 2 (JP2) comprises:
Iberdrola Renewables
Northwest Wind Group

Joint Party 3 (JP3) comprises:
Industrial Customers of Northwest Utilities
Public Power Council

Joint Party 4 (JP4) comprises:
Benton PUD
Klickitat PUD
Okanogan PUD
Pend Oreille PUD
Idaho Falls Power
Western Public Agencies Group
Gray's Harbor PUD
Franklin PUD
Pacific Northwest Generating Cooperative
Snohomish PUD
City of Seattle
City of Tacoma
Cowlitz PUD
Eugene WEB

Joint Party 5 (JP5) comprises:
Avista
PacifiCorp
Portland General Electric
Puget Sound

Joint Party 6 (JP6) comprises:
Public Power Council
Industrial Customers of Northwest Utilities
City of Seattle
Snohomish PUD
City of Tacoma
Pacific Northwest Generating Cooperative
Northwest Requirements Utilities

Joint Party 7 (JP7) comprises:
Public Power Council
Industrial Customers of Northwest Utilities
City of Tacoma

Joint Party 8 (JP8) comprises:
Public Power Council
City of Seattle
City of Tacoma

Joint Party 9 (JP9) comprises:
Industrial Customers of Northwest Utilities
The City of Seattle
Clark Public Utilities

Joint Party 10 (JP10) comprises:
Public Power Council
Industrial Customers of Northwest Utilities

Joint Party 11 (JP11) comprises:
Public Power Council
Northwest Requirements Utilities
The City of Seattle
City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power
Pacific Northwest Generating Cooperative and Members (PNGC Group)
Industrial Customers of Northwest Utilities

Joint Party 12 (JP12) comprises:
Industrial Customers of Northwest Utilities
Public Power Council
City of Seattle / Seattle City Light
Snohomish PUD
Pacific Northwest Generating Cooperative and Members (PNGC Group)

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PART I

GENERAL

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1.0 INTRODUCTION

This Final Record of Decision (ROD) contains the decisions of the Bonneville Power Administration (BPA), based on the record compiled in this rate proceeding, with respect to the adoption of power and transmission rates for the two-year rate period October 1, 2009, through September 30, 2011 (Fiscal Years (FY) 2010-2011). This 2010 Wholesale Power and Transmission Rate Adjustment Proceeding is designed to establish rate schedules and General Rate Schedule Provisions (GRSPs) to replace existing rate schedules and GRSPs, which expire on September 30, 2009. BPA's Integrated Program Review (IPR) and IPR2, which provide portions of the policy context for this rate case, are described in Chapter 2.

This Final ROD follows an evidentiary hearing, briefing, and oral argument before the BPA Administrator. BPA conducted a consolidated rate proceeding, BPA-10, with separate sub-dockets for power (WP-10) and transmission (TR-10). The proceeding was conducted by one hearing officer, operated under a joint schedule, compiled as a single record with separate sections for WP-10 and TR-10, and is summarized in this combined Final Record of Decision. The official record in the WP-07 rate proceeding (including the Supplemental phase) is incorporated by reference into the official record for the WP-10 rate proceeding. WP-10-HOO-09; *see also* section 1.1.5 below.

Sections 4 through 21 of this Final ROD present the issues raised by parties in this proceeding, the parties' positions, BPA Staff positions on the issues, evaluations of the positions, and the Administrator's decisions. This Final ROD also tallies, summarizes, and responds to participant comments (Chapter 17 for power and Chapter 21 for transmission). Participant comments were submitted during the public comment period, which ended May 15, 2009.

1.1 Procedural History of this Rate Proceeding

1.1.1 Issue Workshops

For several months prior to the release of its Initial Proposal, BPA sponsored a series of workshops and technical conference calls on a variety of topics related to its power and transmission ratemaking. These workshops and calls were held so BPA Staff and interested parties could develop a common understanding of the issues, generate ideas, and propose alternative solutions to issues in specific areas when possible. The workshops placed significant emphasis on wind integration, including determination of reserves necessary to integrate wind generation into BPA's Balancing Authority Area.

Conducting the issue workshops prior to the development of the Initial Proposal enabled BPA and interested parties to freely exchange ideas and comments relevant to rate issues without the constraints of the prohibition on *ex parte* communication that go into effect at the onset of the formal rate proceeding. The *ex parte* prohibition went into effect on February 10, 2009, with the publication of the notice of BPA's Initial Proposal in the Federal Register, and ends when BPA issues this Final ROD. The Initial Proposal incorporated many of the ideas and solutions arising from these workshops, and this Final ROD reflects them where appropriate. For Transmission

Services, the workshops culminated in a Partial Settlement Agreement (*see* section 1.1.2, Chapter 18, and Appendix A).

On June 29, 2009, after publication of the Draft ROD, BPA held an informal workshop to present the preliminary final rates, as requested by parties (*see* ROD Chapter 16, Issue 2), and other information designed to inform the parties' Briefs on Exceptions. At that meeting, the Administrator asked the parties to provide specific information in their Briefs on Exceptions to help him reach decisions in this Final ROD.

1.1.2 Transmission Partial Settlement Agreement

As noted above, prior to the start of the BPA-10 rate proceeding, BPA held technical workshops and conference calls to discuss potential rate issues with interested parties. Transmission Services held its first workshop on July 31, 2008. During several of the early workshops, Transmission Services and the parties discussed the possibility of settlement of the transmission issues. At the November 21, 2008, workshop, Transmission Services distributed a list of transmission rate issues for possible settlement and its proposals for resolving each issue. Transmission Services also provided a proposed schedule for the settlement process, which included dates for additional workshops and for distribution of a draft settlement agreement. At the December 5, 2008, workshop, Transmission Services distributed proposed amendments to the rate schedules and proposed transmission rate levels for the FY 2010-2011 rate period, with a view toward settling all issues included in the proposal. After this workshop, Transmission Services posted on its Web site a draft partial settlement agreement, which the parties discussed at a workshop on December 12. Transmission Services then posted a revised agreement, which the parties discussed at a workshop on December 19.

Transmission Services and most of the parties that attended the negotiation sessions reached agreement on the proposed rate levels and the other issues, and the terms were incorporated into the jointly developed partial settlement agreement. On January 5, 2009, Transmission Services sent the proposed Partial Settlement Agreement to the parties for review and signature. The proposed agreement would settle all transmission rates and the rates for the two required Ancillary Services (Scheduling, System Control and Dispatch Service and Reactive Supply and Voltage Control from Generation Sources Service). It also included changes to several other rate schedules. It did not include the remaining Ancillary Service rates or the control area service rates. Transmission Services asked parties to sign and return the agreement by January 16, 2009.

Transmission Services signed the Partial Settlement Agreement after receiving signed agreements from most rate case parties. The signatories include full and partial requirements customers, investor-owned utilities, and independent power producers. The Partial Settlement Agreement is attached as Appendix A. A list of the parties that signed the agreement is Attachment 4 to Appendix A. The TR-10 Initial Proposal reflects the terms of the Partial Settlement Agreement. Bermejo *et al.*, TR-10-E-BPA-06, at 2. *See also* Chapter 18. The Hearing Officer set a date of February 25, 2009, for parties that had not signed the Partial Settlement Agreement to object to the settlement or waive their rights to do so. No party objected to the partial settlement.

1.1.3 Combined WP-10 and TR-10 Rate Proceeding

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

Since BPA formed the separate power and transmission business lines in 1997, it has held separate power and transmission rate proceedings. This year, however, BPA is conducting one rate proceeding with two sub-dockets, one for power rates and one for transmission rates. Both sets of current rates expire September 30, 2009.

On February 10, 2009, BPA published in the Federal Register a Notice of FY 2010-2011 Proposed Power and Transmission Rate Adjustments, 74 Fed. Reg. 6609 (2009). On March 2, 2009, BPA published a corrected notice. *See* Notice of FY 2010-2011 Proposed Power and Transmission Rate Adjustments; Correction, 74 Fed. Reg. 9090 (2009). The corrected notice modified language distinguishing between parties and participants.

On February 10, 2009, BPA held a scheduling conference, at which attendees presented, discussed, and revised draft orders for presentation at the prehearing conference. BPA's 2010 power and transmission rate proceeding began with a prehearing conference on February 18, 2009. Soon after the prehearing conference, the Hearing Officer issued orders establishing the schedule for this rate proceeding, special rules of practice, data request procedures, and general acronyms, and granting petitions to intervene.

BPA Staff's 2010 Initial Proposal, filed on February 18, 2009, is supported by its initial studies and written testimony of witnesses. Clarification of the Initial Proposal, and settlement discussions, took place February 24-27, 2009. The parties filed direct testimony on March 20, 2009, and clarification of their testimony took place on March 26-27, 2009. Staff filed supplemental direct testimony, and litigants filed rebuttal testimony, on April 17, 2009. Clarification of the April 17 testimony took place on April 24, 2009. On May 1, 2009, parties filed rebuttal to Staff's April 17 supplemental direct testimony, direct testimony on limited issues, and sur-rebuttal testimony. Staff filed sur-rebuttal testimony responding to parties' May 1 filings on May 11, 2009. Cross examination was conducted May 11-15, 2009.

The parties filed their Initial Briefs on May 27, 2009. Oral argument before the Administrator took place on June 10, 2009. The Draft Record of Decision was issued June 23, 2009. Briefs on Exceptions were filed July 2, and this Final Record of Decision is being issued, along with final studies, on July 21, 2009.

At times, certain parties to this proceeding consolidated for the purposes of filing testimony or submitting a brief on one or more issues. The rate case clerks assigned each consolidated group of parties (joint party) an alpha-numeric designation (*e.g.*, JP1, JP2, JP3) for the purposes of being considered, collectively, an official rate case party. For convenience, a list of the joint parties appears in the list of Party Abbreviations and Joint Party Designation Codes that is included at the beginning of this Final ROD.

For interested persons who are not eligible or do not wish to become parties to the formal evidentiary hearings, BPA's *Procedures* provide opportunities to participate in the ratemaking process through submission of comments as a "participant." *See* section 1010.5 of BPA's *Procedures.* No party may submit comments as a participant, and comments so submitted will not be included in the record. WP-10-HOO-02. BPA received 400 written comments submitted during the participant comment period, which began with the publication of the notice in the Federal Register on February 10, 2009, and ended May 15, 2009. The comments from these participants are part of the record upon which the Administrator bases his decisions. Comments relevant to WP-10 are summarized and addressed in Chapter 17, and comments relevant to TR-10 are summarized and addressed in Chapter 21. All BPA-10 rate case comments can be viewed at http://www.bpa.gov/applications/publiccomments/CommentList.aspx?ID=61

The power rates sub-docket, WP-10, addresses all power rates issues, including the calculation and pricing of capacity reserves for ancillary and control area services (regulating reserves, operating reserves, and wind balancing reserves). The power rates sub-docket also includes other generation inputs and inter-business line topics, including synchronous condensing, generation dropping, redispatch expense, energy and generation imbalance revenue, segmentation of U.S. Army Corps of Engineers and U.S. Bureau of Reclamation transmission facilities, and station service.

Except for the generation inputs issues listed above that are included in the power rates sub-docket, the transmission rates sub-docket, TR-10, includes all transmission rates issues, including rate design and rate schedules for all ancillary and control area services. BPA's Power Services is a party to the transmission sub-docket for all purposes under BPA's *Procedures,* including for purposes of *ex parte* communications.

1.1.4 Waiver of Issues by Failure to Raise in Briefs

Pursuant to section 1010.13(b) of the *Procedures,* arguments not raised in parties' briefs are deemed to be waived. Under this provision, a party's brief must specifically address the legal or factual dispute at issue. Blanket statements that seek to preserve every issue raised in testimony will not preserve the matter at issue.

However, a party need only raise an issue in either its Initial Brief or its Brief on Exceptions. While a party may wish to reassert an issue for other reasons, the party need not reassert an issue in its Brief on Exceptions in order to avoid waiving the issue. All arguments raised by a party in its Initial Brief shall be deemed to have been raised in the party's Brief on Exceptions. WP-10-HOO-02.

1.1.5 Incorporation of the WP-07 Supplemental Rate Proceeding Record into the WP-10 Rate Record

Following the completion of the WP-07 Supplemental rate proceeding in September 2008, BPA began preparations for the commencement of the WP-10 rate proceeding. As BPA prepared its Initial Proposal, it became apparent that many of the issues addressed in the WP-07 Supplemental rate proceeding would be relevant again in the WP-10 rate proceeding. This overlap concerned BPA because, unless an intermediary action was taken, many of the issues argued and decided in the WP-07 Supplemental rate proceeding would have to be reargued in the WP-10 rate proceeding to preserve such arguments for any subsequent appeals in the WP-10 rates. Because most of these issues had already been thoroughly argued in the WP-07 Supplemental rate proceeding, it would not have been a prudent use of BPA's or the parties' resources to engage in the formal process of resubmitting in this case all of the prior evidence and arguments.

In December 2008 and January 2009, BPA held publicly noticed meetings to discuss with interested parties ways of preserving the arguments and evidence from the previous rate proceeding without substantially increasing the administrative burden of the WP-10 rate proceeding. Eventually, a consensus was reached among BPA and a number of parties that the simplest option was for BPA to file a proposed Order with the Hearing Officer that preserved in the WP-10 rate proceeding certain arguments that BPA and the parties made in the WP-07 Supplemental rate proceeding. In general, the proposed Order would preserve two aspects of the WP-07 Supplemental rate proceeding. First, it would preserve the evidence submitted in the WP-07 Supplemental rate proceeding for use in the WP-10 rate proceeding. Second, it would preserve in the WP-10 rate proceeding certain arguments raised by the parties (and BPA's responses) in the WP-07 Supplemental rate proceeding. The terms of the proposed Order were crafted as part of a "Standstill Agreement" executed between BPA and these parties.

On February 25, 2009, BPA filed a motion requesting the Hearing Officer to adopt the proposed Order negotiated by BPA and the parties. Motion of BPA for the Adoption of Proposed Order, WP-10-M-BPA-01. No party opposed BPA's motion. On March 6, 2009, the Hearing Officer granted BPA's motion and adopted the proposed Order. Order Incorporating Arguments and Evidence From the WP-07 Supplemental Record Into the WP-10 Wholesale Power Rate Adjustment Proceeding, WP-10-HOO-09 ("Incorporation Order"). The Hearing Officer's Incorporation Order states as follows:

> …The official record of the WP-07S Proceeding is hereby incorporated by reference in its entirety into the official record of this case for the purposes of (a) providing such information as may be necessary to establish and thereafter justify the proposed WP-10 Wholesale Power Rates, and (b) preserving for the parties in this proceeding and BPA the arguments presented in the WP-07S Proceeding and all record bases in support thereof regarding the issues identified in Section 5 of this Order. If the WP-10 Wholesale Power Rate Adjustment Proceeding is challenged before the United States Court of Appeals for the Ninth Circuit, BPA will ensure that all record materials, including those record materials relevant to the issues identified in Section 5 of this Order, will be made part of the administrative record on review that BPA submits to the Court.

Id. Despite the assurances afforded in the Incorporation Order, a number of parties have re-raised their prior positions from the WP-07 Supplemental rate proceeding in this proceeding. BPA does not intend to respond to the individual arguments of parties that seek to re-argue or re-raise issues that are addressed by the Incorporation Order. Further evaluation or analysis of these matters in this case would undermine the efficiency and expediency that BPA and parties have achieved through the development of the Incorporation Order. BPA's prior responses in the 2007 Supplemental Wholesale Power Rate Case Administrator's Final Record of Decision (WP-07 Supplemental ROD) constitute the agency's decisions and rationale in the WP-10 rate proceeding for any issue within the scope of the Hearing Officer's Incorporation Order, unless otherwise stated in this Final Record of Decision.

1.2 Legal Guidelines Governing Establishment of Rates

1.2.1 Statutory Guidelines

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

Section 7(a)(1) of the Northwest Power Act reaffirms the applicability of section 5 of the Flood Control Act of 1944 (Flood Control Act), which directs that rate schedules should encourage the most widespread use of power at the lowest possible rates to consumers consistent with sound business principles. 16 U.S.C. § 825s. Section 5 of the Flood Control Act 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.*

Section 7(a)(1) of the Northwest Power Act also reaffirms the applicability of sections 9 and 10 of the Federal Columbia River Transmission System Act of 1974, 16 U.S.C. § 838 (Transmission System Act), which contains requirements similar to those of 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 to consumers 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.

1.2.2 The Broad Ratemaking Discretion Vested In the Administrator

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

The United States Court of Appeals of the Ninth Circuit (Ninth Circuit) has recognized the Administrator's ratemaking discretion. *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1120-29 (9th Cir. 1984) ("[b]ecause BPA helped draft and must administer the Northwest Power Act, we give substantial deference to BPA's statutory interpretation"); *PacifiCorp v. FERC*, 795 F.2d 816, 821 (9th Cir. 1986) ("BPA's interpretation is entitled to great deference and must be upheld unless it is unreasonable"); *Atlantic Richfield Co. v. Bonneville Power Admin.*, 818 F.2d 701, 705 (9th Cir. 1987) (BPA's rate determination upheld as a "reasonable decision in light of economic realities"); *Department of Water and Power of the City of Los Angeles v. Bonneville Power Admin.*, 759 F.2d 684, 690 (9th Cir. 1985) ("Insofar as agency action is the result of its interpretation of its organic statutes, the agency's interpretation is to be given great weight"); *Public Power Council v. Bonneville Power Admin.* 442 F.3d 1204 (9th Cir. 2006). ("[GRSPs] are entirely bound up with BPA's rate making responsibilities, and we owe deference to the BPA in that area"). The Supreme Court of the United States has also recognized the Administrator's ratemaking discretion. *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").

1.3 Federal Energy Regulatory Commission Confirmation and Approval of Rates

BPA's rates become effective upon confirmation and approval by the Federal Energy Regulatory Commission (Commission). 16 U.S.C. §839e(a)(2) and (k). The Commission's review is appellate in nature, based on the record developed by the Administrator. *United States Department of Energy—Bonneville Power Admin.*, 13 FERC ¶ 61,157, 61,339 (1980). The Commission may not modify rates proposed by the Administrator but may only confirm, reject, or remand them. *United States Department of Energy—Bonneville Power Admin.*, 23 FERC ¶ 61,378, 61,801 (1983). Pursuant to section 7(i)(6) of the Northwest Power Act, 16 U.S.C. §839e(i)(6), the Commission has promulgated rules establishing procedures for the approval of BPA rates. 18 C.F.R. Part 300 (1997).

1.3.1 Standard of Commission Review

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

1.3.2 Inter-Business Line Charges

Certain inter-business line costs and unit costs established in the WP-10 sub-docket will be used as inputs for the development of transmission and Ancillary Services rates in the TR-10 sub-docket. BPA Power Services provides a portion of the generation available from the FCRPS to Transmission Services to enable Transmission Services to maintain reliability. BPA assigns the costs of this generation to the transmission function, which then assigns them to transmission rates. The affected ancillary and control area services are 1) balancing for wind service, which provides balancing services for wind integration; 2) regulation and frequency response service, which provides the generation capability to follow the moment-to-moment variations of loads in the BPA Balancing Authority Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards; 3) energy imbalance service, which is taken when there is a difference between scheduled and actual energy delivered to a load in the BPA Balancing Authority Area during a schedule hour; 4) operating reserve – spinning reserve service, which serves load immediately in the event of a system contingency; 5) operating reserve – supplemental reserve service, which is generation available within a short period of time to serve load in the event of a system contingency; and 6) generation imbalance service, which is taken when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Balancing Authority Area during a schedule hour. Other generation costs that BPA assigns to the transmission function include costs of synchronous condensing, generation dropping, station service, and the segmented costs of U.S. Army Corps of Engineers and Bureau of Reclamation transmission facilities. The final transmission rates will reflect the Administrator's final decisions regarding inter-business line issues.

2.0 OVERALL POLICY CONTEXT

2.1 Introduction

This section includes discussion of a process integral to but separate from the rate proceeding that provides information and policy context to the 2010 Final Proposal—the Integrated Program Review (IPR), including IPR2. This section also addresses the level of the proposed power rate increase and its relation to the current economic situation.

2.2 Integrated Program Review

Since 1986, BPA has conducted a review of planned spending levels used in the development of rates in a process separate from the rate proceeding. In recent years, power and transmission costs were considered in separate processes, because power and transmission rate cases were on different schedules. Prior to this rate proceeding, BPA began the Integrated Program Review (IPR) process in May 2008 in response to customer and stakeholder requests for a consolidated program-level review of the planned expenses that would be included in setting power and transmission rates. The IPR process provides persons interested in BPA's program levels an opportunity to review and comment on all of BPA's expense and capital spending level estimates prior to the use of those estimates in setting rates. Between May and August 2008, BPA held 17 IPR workshops, which discussed proposed spending levels for each of BPA's programs. BPA reviewed and considered the comments on FY 2010-2011 program levels that were made during this public process when making its decisions. On November 14, 2008, BPA issued the Close-Out Letter and accompanying Final Report for the IPR, which summarized the comments and outlined BPA's responses. In the Close-Out Letter and Final Report, BPA presented the program-level cost estimates that were used in the WP-10 and TR-10 Initial Proposals. BPA also committed to reassess the program spending levels to determine if further cost changes would be appropriate and to conduct an abbreviated public review (IPR2) in the spring of 2009.

On March 18, 2009, BPA held the first IPR2 workshop. The Administrator and other BPA executives met with customers and other interested parties to review spending level decisions presented in the November 2008 IPR report. After the November 2008 IPR report was issued and the Initial Proposal was published, the state of the regional economy and BPA's financial outlook changed significantly. The global financial market crisis and the deterioration of the U.S. economy caused high unemployment and severe financial circumstances for many in the Northwest. At the same time, BPA's financial situation had declined due to continuing poor hydro conditions and lower than anticipated power market prices, resulting in the potential for an even larger increase in power rates for FY 2010-2011 than anticipated in the Initial Proposal. BPA recognized the serious impact a large power rate increase could have on the region in the current economic downturn.

After working internally and with its partner agencies, BPA held a second IPR2 workshop on April 9, 2009, where BPA provided a status update on cost reduction efforts. At the final IPR2 meeting, held April 29, 2009, the Administrator and other BPA executives discussed and received comments on the revised proposed spending levels. The IPR2 comment period closed

May 4, after which final program levels to be used in the BPA-10 final rates were determined. *See* Bonneville Power Administration Integrated Program Review 2 FY 2010-2011 Power and Transmission Program Levels Final Report (June 19, 2009).

While BPA continues to believe the proposed spending levels identified in the initial IPR process were appropriate and prudent from both long- and short-term perspectives existing in mid-2008, BPA determined that it is important that short-term cost-cutting actions be taken to help minimize the increase to power rates. Significant reductions in program level forecasts were identified during the IPR2 process, including total reductions affecting power rates of $106 million over the FY 2010-2011 rate period and an additional $43 million for FY 2009. These reductions do not include potential reductions to debt service and power purchase expense, which are not determined in the IPR process. These reductions made a major contribution to the effort to reduce the size of the WP-10 Priority Firm Power (PF) rate increase. *See* section 2.3, below.

Transmission costs were reduced by about $30.6 million for the FY 2010-2011 rate period, primarily due to reductions in Agency Services costs that are allocated to Transmission Services, as well as re-allocation of forecast spending from expense to capital.

As noted in the Federal Register Notice that published BPA's Initial Proposal, the IPR process is separate from the rate proceeding. 74 Fed. Reg. 6609 (February 10, 2009). Thus, cost levels are not at issue in the rate proceeding. Lovell *et al.*, WP-10-E-BPA-48, at 7.

2.3 Managing the Power Rate Increase

BPA Staff's initial policy testimony in this proceeding describes the size of the proposed rate increases for the PF, Industrial Firm Power (IP), and New Resources Firm Power (NR) rates. Bliven and Lefler, WP-10-E-BPA-10, at 2. It also discusses the factors that led to the proposed power rate increases and the factors that might cause the WP-10 final rate increases to be even larger. *Id*. at 3. These factors are primarily cost increases. *Id*.

Two months after the Initial Proposal, Staff filed additional direct testimony for the specific purpose of discussing means of managing the level of the rate increase. Lovell *et al.*, WP-10-E-BPA-33. That testimony describes the changes that occurred since the Initial Proposal that, without further action, were likely to result in a rate increase even higher than the 9 percent proposed in the Initial Proposal for the PF rate. Staff states that "given the current economic conditions, both regionally and nationally, such a large rate increase is not appropriate." *Id*. at 2.

The two major areas of change that Staff witnesses explain could lead to a power rate increase higher than proposed in the Initial Proposal are as follows. First, local, regional, national, and global economies have declined in the last few months and continue to decline, and the timing (and extent) of any recovery is difficult to predict. As a result, BPA's forecast loads (*i.e.*, sales) likely will show economy-related declines, reducing BPA's revenue but also reducing needed augmentation purchases. Second, actual FY 2009 natural gas prices and forecast natural gas prices for the remainder of FY 2009, as well as the rate period, FY 2010-2011, have declined since the Initial Proposal. When gas prices decline, electricity prices generally also decline, resulting in lower BPA net secondary revenues. Lower net secondary revenues can drive firm power rates higher. This effect can be mitigated by reductions in power purchases and financial risks, which can reduce upward pressure on rates.

After filing its Initial Proposal, Staff met in settlement discussions with rate case parties to discuss a set of tools to mitigate the power rate increase. (Concurrent with and separate from the rate proceeding, the IPR2 process discussed potential cost reductions that could mitigate the rate increase, as described in section 2.2 above.) During these discussions, Staff and parties began to develop a clearer picture of what BPA's final power rate proposal might be, given the changes in some of the base assumptions. Staff developed a series of 30 scenario analyses that considered three different gas prices for FY 2010-2011, two levels of cost reductions, and two amounts of additional liquidity. In addition, two different levels of Power's FY 2009 financial results were factored into this analysis. *Id*. at 20. These cost and risk analyses were not provided as an update to the Initial Proposal or as a new proposal; they were meant to illustrate the kind of impact on rates potential changes in various factors could have. *Id*. at 21 and Attachment 1.

Several options were discussed that could increase BPA's ability to address within-year liquidity needs. Staff's recommendation after reviewing the results of these scenarios was that determining means for supporting Power Services Treasury Payment Probability (TPP), with a $400 million liquidity target level, should be prioritized as follows. Staff recommended that if BPA reached agreement with Treasury that expanded BPA's ability to borrow at least an additional $400 million in the short term for expenses, that facility would be the sole source of the additional liquidity needed for ratesetting purposes. *Id*. at 24. Second in priority would be the Flexible PF Rate Program to the extent necessary to provide up to $400 million of additional liquidity. *Id*. Third would be reliance on unused Transmission cash reserves. *Id*.

BPA announced at the April 29 IPR2 close-out meeting that the U.S. Treasury had expanded BPA's ability to borrow in the short term from the U.S. Treasury. This increases BPA's available liquidity from $300 million to $750 million. The cash proceeds from the borrowing can be made available to BPA in a matter of hours. Such borrowing would need to be repaid by the earlier of two years after the original issue date or by the end of April 2013. This additional $450 million can be considered liquidity available to support Power Services TPP. *See* Chapter 7.

<u>Issue 1</u>

Whether BPA should eliminate any increase for the PF rate for the FY 2010-2011 rate period.

<u>Parties' Positions</u>

Cowlitz PUD makes note of the current severe recession. Cowlitz Br., WP-10-B-CO-01, at 2-3; Cowlitz Br. Ex., WP-10-R-CO-01, at 1. Cowlitz states that the whole region is engaged in the process of minimizing near-term suffering and long-term damage of the recession to consumers and service territories by minimizing costs or at least deferring them out of the period likely to be the bottom of the recession. Cowlitz Br., WP-10-B-CO-01, at 3.

Seattle also notes that the Northwest's economy is confronting extraordinary challenges, with job losses and resulting load loss; for some preference utilities in the region, the impact has been severe. Seattle Br., WP-10-B-SE-01, at 1-2. Many of BPA's customers are seeking every available tool to cut costs or defer them into the future, and everything that can be done to avoid compounding the region's economic woes should be done. *Id.* at 3.

CUB describes the current recession as second only to the Great Depression and states that utility consumers are facing huge economic challenges. CUB Br., WP-10-B-CU-01, at 2. CUB Br. Ex., WP-10-R-CU-01 at 1. CUB states that it hopes that BPA will find a way to moderate the increase in rates. CUB Br., WP-10-B-CU-01, at 3. Given the large load reduction that is anticipated to follow the recession, CUB states, moderating the rate hike should not only be possible, but essential and required. *Id.*

ICNU states that BPA should not increase the PF rate for FY 2010-2011 due to the current state of the economy. ICNU Br., WP-10-B-IN-01, at 1, 3. ICNU states that BPA should take all reasonable actions to reduce costs, shift costs into future periods, and postpone new programs in order to eliminate a potential rate increase. *Id.* at 4.

PPC *et al.* state that despite the dampening of the rate increase that appears to have been achieved in the WP-10 rate proceeding, the fact remains that any rate increase is harmful to the local economies of BPA's customers at this difficult time. PPC *et al.* Br., WP-10-B-JP11-01, at 2; PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 2. PPC *et al.* state that BPA should take every reasonable measure to reduce the size of any rate increase. PPC *et al.* Br., WP-10-B-JP11-01, at 2; PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 2-3.

NRU states that it is important for the Administrator to make decisions regarding the issues raised in this case such that the final rate increase, if any, is as small as possible consistent with meeting the agency's statutory obligations. NRU Br., WP-10-B-NR-01, at 2. NRU states that the preliminary final rate increase BPA presented at the June 29, 2009, rate case workshop is too high. NRU Br. Ex., WP-10-R-NR-01, at 1. NRU strongly urges BPA to reduce the rate increase to no more than 5 percent. *Id.*

WPAG states that the economic plight of preference customers requires the elimination of any PF rate increase. WPAG Br., WP-10-B-WG-01, at 2; WPAG Br. Ex., WP-10-R-WG-01, at 4-5, 26.

PNGC Group states that BPA's proposed increases to the rates paid by its preference customers are unreasonable under the current economic downturn, and BPA should use every measure at its disposal to reduce all costs recovered in its rates. PNGC Br. Ex., WP-10-R-PN-01, at 5-6.

BPA Staff's Position

The discussion above in section 2.3 summarizes BPA's efforts to minimize the rate increase during the rate proceeding.

Evaluation of Positions

Parties state that BPA should minimize the amount of increase to the PF rate for the FY 2010-2011 rate period, or preferably, eliminate any rate increase. They cite the current recession and the unhealthy climate for business, including BPA's utility customers.

BPA is sensitive to the current economic climate in the Pacific Northwest. The breadth and depth of the recession's severity became evident as BPA was finalizing the Initial Proposal. During this time, it also became apparent that lower-than-normal streamflows were negatively affecting BPA's finances in FY 2009. BPA was faced with choices in its response: 1) delay the Initial Proposal to address the situation, thereby jeopardizing the ability to have rates ready for October 1, 2009, or 2) release the Initial Proposal and immediately begin working on revisions that would mitigate the impact of BPA's rate increase on the regional economy. BPA chose the latter.

As discussed earlier in this section, immediately after the Initial Proposal, Staff began settlement discussions with rate case parties to develop tools and policy alternatives to reduce the size of the power rate increase. Through their hard work, Staff and parties were able to combine the lower spending levels resulting from IPR2 and the elimination of PNRR resulting from the new Treasury note to greatly reduce the size of the rate increase. This work with parties documents that BPA is cognizant of the economic plight of the region and is willing to do all it reasonably can to respond.

At oral argument, many parties recognized and expressed appreciation for the efforts by Staff to work with parties. Cowlitz stated that it appreciates the effort that Bonneville has taken to minimize the rate increases necessary to keep BPA sound and stated that those efforts would help Cowlitz and its customers. Murphy, Oral Tr. at 109. ICNU expressed its appreciation for BPA's Staff and that they did an excellent job in working with the parties. Sanger, Oral Tr. at 207. ICNU continued by saying that once the Initial Proposal was filed, everybody, and especially the Staff, rolled up their sleeves and looked at all available options for lowering the rate increase and potentially keeping the rates at the current level. *Id*. PPC *et al.* stated that BPA probably has not been thanked enough by anybody for the efforts of Staff and BPA management to try to reach new arrangements that would help the rates. Thompson, Oral Tr. at 132-133. NRU stated that the Staff is to be commended in particular for the tightening of the belt more than a couple of extra notches to achieve cost reductions rather than simply relying on new and creative financing mechanisms to avoid short-term financial problems. Saven, Oral Tr. at 215. WPAG stated that BPA management and Staff have dealt remarkably with a tough set of circumstances, finding itself with a rate proposal that was essentially outmoded by events that no one saw coming. Mundorf, Oral Tr. at 222-223.

BPA also appreciates the opportunity to work with parties in such a professional, candid, and collaborative manner and thanks the parties for their recognition of Staff's efforts.

The question, though, is whether BPA can eliminate the rate increase given what is before it today. Despite all of the hard work by Staff and parties, some obstacles may be too significant to allow not increasing power rates. BPA is still faced with some significant cost increases.

Electric market conditions do not appear as though they will completely recover soon, eroding secondary revenues, a significant source of BPA's revenue.

As summarized in ROD section 1.2, BPA must follow legal (statutory and other) guidelines when establishing rates. As noted in section 1.2.2, the Administrator has a certain amount of ratemaking discretion. For power rates, the Commission reviews BPA power rates under the Northwest Power Act to determine whether 1) rates are sufficient to ensure repayment of the Federal investment in the FCRPS over a reasonable number of years after first meeting BPA's other costs; and 2) rates are based on BPA's total system costs.

The Administrator's decisions in this Final ROD reflect a careful balancing of all interests and legal obligations in this proceeding. BPA has incorporated all of the spending level reductions identified in IPR2. BPA has fully reflected the effectiveness of the liquidity resulting from the expanded Treasury note to reduce PNRR to zero. The interest rate forecast was revised to better reflect expected economic conditions. But BPA also recognizes that lower natural gas and electric market prices, while lowering purchase power and augmentation expenses, will result in lower expected secondary revenues. The decision to include a small amount of service to DSIs also adds a net cost to BPA. The decisions on the section 7(b)(2) rate test and resulting 7(b)(3) cost reallocations minimally reduced REP benefits.

The result of this balancing of interests, and the fact that BPA cannot ignore its statutory mandate to set rates that are sufficient to meet its repayment and cost obligations, is that BPA cannot completely eliminate the rate increase. The rate increase is lower than the Initial Proposal and is much lower than it would have been had the actions outlined in this ROD not occurred, but still, despite all of this good work, an increase remains.

Decision

BPA will set the level of the PF rate for the FY 2010-2011 rate period based on statutory requirements to recover costs and repay the U.S. Treasury in full and on time, even though it results in a rate increase.

3.0 NATIONAL ENVIRONMENTAL POLICY ACT ANALYSIS

3.1 Introduction

BPA has assessed the potential environmental effects that could result from decisions being made through the 2010 Wholesale Power and Transmission Rate Adjustment Proceeding, consistent with the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321, *et seq*. The NEPA analysis is conducted separately from the formal rate process.

BPA has previously prepared a policy-level Business Plan Final Environmental Impact Statement (Business Plan EIS), which evaluates the environmental impacts of a range of business structure alternatives that include, among other things, various rate designs for BPA's power and transmission products and services. (DOE/EIS-0183, June 1995). The BPA Administrator also has issued a Record of Decision (Business Plan ROD, August 1995), which adopted the Market-Driven alternative from the Business Plan EIS. As discussed in more detail below, the BPA-10 rate proposal falls within the scope of the Market-Driven alternative and is not expected to result in environmental impacts that are significantly different from those examined in the Business Plan EIS. The decision to implement this rate proposal thus is tiered to the Business Plan ROD.

(Although BPA is electing to tier its decision to the Business Plan ROD, BPA notes that this rate proposal is the type of action typically excluded from NEPA pursuant to U.S. Department of Energy NEPA regulations, which are applicable to BPA. More specifically, this rate proposal falls within Categorical Exclusion B4.3, found at 10 CFR 1021, Subpart D, Appendix B, which provides for the categorical exclusion from NEPA documentation of "[r]ate changes for electric power, power transmission, and other products or services provided by a Power Marketing Administration that are based on a change in revenue requirements if the operations of generation projects would remain within normal operating limits." Nonetheless, BPA has laid out a strategy in the Business Plan EIS and ROD for NEPA compliance concerning future business-related decisions, and believes that a ROD tiered to the Business Plan ROD is an appropriate means for ensuring NEPA consideration of this rate proposal.)

3.2 Business Plan EIS and ROD

The Business Plan EIS was prepared in response to a need for an adaptive business policy that would allow BPA to be more responsive to the evolving and increasingly competitive wholesale electricity market, while still meeting both its business and public service missions. Accordingly, BPA designed the Business Plan EIS to support a wide array of business decisions, including decisions related to rates for products and services in rate cases in 1995 and thereafter. Business Plan EIS, section 1.4. BPA identified several purposes for consideration, including achieving strategic business objectives; competitively marketing BPA's products and services; providing for equitable treatment of Columbia River fish and wildlife; achieving BPA's share of the Northwest Power and Conservation Council's conservation goal; establishing rates that are easy to understand and administer, stable, and fair; recovering costs through rates; meeting legal mandates and contractual obligations; avoiding adverse environmental impacts; and establishing productive government-to-government relationships with Indian Tribes. *Id*., section 1.2; Business Plan ROD, sections 5 and 6.

BPA's Business Plan EIS evaluates six alternative business directions: Status Quo (No Action); BPA Influence; Market-Driven; Maximize Financial Returns; Minimal BPA; and Short-Term Marketing. Each of the six alternatives provides policy direction for deciding 19 major policy issues that fall into five broad categories: Products and Services, Rates, Energy Resources, Transmission, and Fish and Wildlife Administration. Business Plan EIS, section 2.4. Table 2.4-1 of the Business Plan EIS shows how the alternatives evaluated in the Business Plan EIS treat these issues. Four policy options, or modules, were also developed in the Business Plan EIS to allow variations of the alternatives in key areas, including rate design.

The alternatives and modules are designed to cover the range of options for the important issues affecting BPA's business activities, as well as the impacts of those options. Variations can be assembled by matching issues and substituting modules among the six alternatives. *Id*., section 2.1.2. All of the alternatives and modules are examined under two widely different hydrosystem operations strategies that served as "bookends" for reasonably possible operations of the FCRPS. These alternatives thus represent a range of reasonable alternatives for BPA's business activities and BPA's ability to balance costs and revenues.

The Business Plan EIS focuses on BPA relationships to the market. Business Plan EIS, section 2.1. BPA's business decisions, such as setting or revising rates, do not have a direct effect on the environment; rather, environmental impacts are determined indirectly by market responses to BPA's marketing actions and business decisions. *Id*., sections 2.1.5 and 4.1.2. These market responses, discussed in detail in section 4.2 of the Business Plan EIS, are resource (including conservation) development; resource operation; transmission development and operation; and consumer behavior. These market responses can result in a variety of environmental impacts, including air, land, and water impacts, as well as socioeconomic impacts. *Id*., Figures 2.1-1 and S-2. For wholesale power and transmission ratemaking, the Business Plan EIS describes how BPA rates can affect the environment through market responses. *Id*. at section 2.4.2 and Figure 2.4-1.

Thus, the Business Plan EIS is based on a "relationship analysis." BPA has quantitatively and qualitatively evaluated relationships between variables in the short run and assumed that these relationships will hold true in the long term. This relationship-based approach serves as the foundation for the environmental analyses of alternatives and modules in sections 4.4 and 4.5 of the Business Plan EIS.

To determine the potential environmental consequences of the various alternatives, the Business Plan EIS identifies general market responses to key policy issues. *Id*., Table 4.2-1. The market responses for products and services are discussed for each of the alternative business directions, and the market responses for rates also are discussed. *Id*., sections 4.2.1 and 4.2.2. The market responses and the environmental consequences are discussed both in general terms and in terms specific to each alternative. *Id*., section 4.3. Table 4.3-1 details the typical environmental impacts from power generation and transmission. Section 4.4 presents the market responses and environmental impacts by alternative under each of the two bookend hydro operation scenarios.

Section 4.4.3 also includes an illustrative numerical example. Table 4.4-19 summarizes the key environmental impacts by alternative. *Id*., section 4.4.3.8. In addition, Appendix B to the Business Plan EIS includes an extensive evaluation of rate design, including market response and environmental impacts. *Id*., Appendix B. As can be seen from the environmental analyses summarized in Tables 4.4-19 and 4.4-20, differences in total environmental impacts among the alternatives are relatively small.

Each of the alternative business directions examined in the Business Plan EIS was also evaluated against the purposes for the action to determine how well each of the alternatives meets the need. *Id*., section 2.6.5. Based on the evaluation of potential environmental impacts and the comparison of each alternative to the identified purposes, the Administrator adopted the Market-Driven alternative as the Agency's overall business policy in the Business Plan ROD. Business Plan ROD, section 6. The Market-Driven alternative strikes a balance between marketing and environmental concerns. It also assists BPA in maintaining the financial strength necessary to continue a relatively high level of support for public service benefits, such as energy conservation and fish and wildlife mitigation activities, while keeping BPA rates and the costs of other BPA products and services as low as possible.

Recognizing that the Administrator could select a variety of actions, BPA included many mitigation response strategies in the Business Plan EIS and ROD to address changed conditions and allow the Agency to balance costs and revenues. These response strategies include measures that BPA could implement to increase revenues (including rates), decrease spending, and/or transfer costs if its costs and revenues do not balance. Business Plan EIS, section 2.5; Business Plan ROD, section 7. These strategies enable BPA to best meet its financial, public service, and environmental obligations while remaining competitive. In the Business Plan ROD, the BPA Administrator decided to implement as many response strategies, or equivalents, as necessary to balance costs and revenues. Business Plan ROD, section 7.

The Business Plan EIS and ROD also document a decision strategy for tiering subsequent business decisions to the Business Plan ROD. Business Plan EIS, section 1.4; Business Plan ROD, section 8. For each such decision, as appropriate, the BPA Administrator reviews the Business Plan EIS and ROD to determine whether the proposed subsequent decision falls within the scope of the Market-Driven Alternative evaluated in the EIS and adopted in the ROD. If the proposed decision is found to be within the scope of this alternative, the Administrator may tier his decision under NEPA to the Business Plan ROD. Business Plan ROD, section 8. Tiering a ROD to the Business Plan ROD helps BPA delineate its business decisions clearly and provides a logical framework for connecting broad policy decisions to more specific actions. Business Plan EIS, section 1.4.

Since 1995, over 40 business decisions have been implemented by tiering RODs for each decision to the Business Plan ROD. RODs tiered to the Business Plan ROD have been completed for a broad array of BPA business decisions, such as rates for power products and services, rates for transmission products and services, power sales contracts, transmission agreements, power interconnection projects, power subscription, interconnection of energy development projects, and cost recovery adjustment clauses. Through these RODs, BPA also has evaluated the accuracy of its assumption, made in the Business Plan EIS, that the short-term relationships among variables would hold true in the long term. BPA has found these relationships have stayed largely the same where relevant to environmental concerns. In April 2007, BPA completed a review of the Business Plan EIS and ROD through a Supplement Analysis, as provided for in NEPA regulations applicable to BPA. The Supplement Analysis was prepared to assess whether the Business Plan EIS still provides an adequate evaluation, at a policy level, of environmental impacts that may result from BPA's current business practices, and whether these practices are still consistent with the Market-Driven alternative adopted in the Business Plan ROD. Changes that have occurred in the electric utility market and the existing environment were evaluated, and developments that have occurred in BPA's business practices and policies were considered. The Supplement Analysis found that the Business Plan EIS's relationship-based and policy-level analysis of potential environmental impacts from BPA's business practices remains valid, and that BPA's current business practices are still consistent with BPA's Market-Driven approach. The Business Plan EIS and ROD thus continue to provide a sound basis for making determinations under NEPA concerning BPA's policy-level decisions.

3.3 Environmental Analysis

The Business Plan EIS and ROD were reviewed to determine whether the BPA-10 rate proposal is adequately covered within the scope of the EIS and the Market-Driven alternative adopted in the Business Plan ROD. The Business Plan EIS includes analysis of the same rate-related issues associated with decisions being made through the BPA-10 rate case. The key policy issues analyzed in the Business Plan EIS include several rates-related decisions, such as unbundling or rebundling of BPA's power and transmission products and services, and pricing. The modules include a range of rate design options, including tiered rates, streamflow-based rates, seasonal rates, surcharges, market-based pricing, and elimination of existing rate discounts.

As discussed above, the Business Plan EIS identifies general market responses to BPA actions, such as establishing or revising rates, and these market responses are the source of environmental impacts. More specifically, the primary environmental impacts of power and transmission prices and rate attributes are through the choices customers make for generation resources and conservation and also in their preferred transmission provider. Business Plan EIS, sections 4.2.2.2 and 4.5.2. For example, increasing rates may cause more customers to seek energy on the market, may encourage customers to develop their own generation resources, or may cause more customers to seek alternative transmission providers or construct new transmission facilities. If this were to occur, customers may potentially develop or purchase energy from thermal generation, which in theory could be less expensive. Transmission and wheeling pricing could also influence customer decisions on resource siting, or the marketability of resource output based on the influence of wheeling costs on the total cost to the purchaser of power services offered by different suppliers. This market response could increase various environmental impacts, such as air pollution from nitrogen, sulfur and carbon emissions, water use, and land use impacts.

It is expected that these types of indirect environmental effects, as well as their potential to occur, from market responses to the BPA-10 rate proposal would be consistent with those effects identified in the Business Plan EIS. The relationships between BPA's rates-related actions and market responses have not changed significantly relative to environmental concerns since they were analyzed in the Business Plan EIS. In addition, hydrosystem operations will not be affected by the BPA-10 rate proposal. BPA already has mechanisms in place to serve its contractual obligations and market power and services with available resources consistent with the operating constraints that apply to the hydrosystem, consistent with the Business Plan EIS and ROD. Business Plan EIS, section 1.5.6; Business Plan ROD, page 4. Through the BPA-10 rate proceeding, BPA also is taking steps to ensure that sufficient generating reserves from the Federal hydrosystem, needed for integration of wind resources into BPA's transmission network, continue to be available as the Northwest continues to experience significant growth of wind development while simultaneously seeking to ensure that hydrosystem operations are not negatively affected.

Based on the review of the Business Plan EIS and ROD, the BPA-10 rate proposal is a direct application of the Market-Driven alternative. This rate proposal continues most of the elements of BPA's existing rate design, with few changes and modifications. Even with the relatively few revisions, the rate proposal remains consistent with the type of rate designs identified and evaluated in the Business Plan EIS.

This rate proposal thus is consistent with the competitive and unbundled, yet cost-based, characteristics of the Market-Driven alternative. The issues related to this proposal are consistent with the analysis of key policy issues related to power and transmission products and services identified for the Market-Driven alternative. *Id*., sections 2.2.3 and 2.6. In addition, this rate proposal does not differ substantially from the types of rate designs considered and evaluated in the Business Plan EIS. *Id*., sections 2.4.1.6, 2.4.2.2, 2.44, and Appendix B. Therefore, the 2010 Wholesale Power and Transmission Rate Adjustment Proceeding falls within the scope of the Market-Driven Alternative that was evaluated in the Business Plan EIS and adopted in the Business Plan ROD. Because of these consistencies, implementation of this rate proposal will not result in significantly different environmental impacts from those examined for the Market-Driven alternative in the Business Plan EIS.

Furthermore, the BPA-10 rate proposal will assist BPA in accomplishing the goals of the Market-Driven Alternative identified in the Business Plan ROD. This alternative was selected as BPA's business direction because, among other reasons, it allows BPA to 1) recover costs through rates; 2) competitively market BPA's products and services; 3) develop rates that meet customer needs for clarity and simplicity; and 4) continue to meet BPA's legal mandates.

The BPA-10 rate proposal provides a competitive rate structure that includes various mechanisms to account for potential revenue shortfalls. The rate proposal thus allows BPA to continue to recover its costs though its rates while remaining competitive, and is consistent with the general approach to setting rates and managing and responding to risk that was developed in the Market-Driven alternative and continued through subsequent rate cases. In addition, the rate design included in the rate proposal has been made as clear and simple as possible, given the various types of products and services covered in the proposal. Finally, BPA believes that the rate proposal will allow BPA to meet all of its applicable legal mandates. Accordingly, the BPA-10 rate proposal is consistent with these aspects of the Market-Driven Alternative.

3.4 Public Comments

The public comment period for the BPA-10 rate proposal closed May 15, 2009. There were no issues relevant to BPA's environmental analysis of the proposal under NEPA raised during the comment period or in parties' briefs.

Decision

Based on a review of the Business Plan EIS and ROD, BPA determines that the BPA-10 rate proposal falls within the scope of the Market-Driven alternative evaluated in the Business Plan EIS and adopted in the Business Plan ROD. The BPA-10 rate proposal is not expected to result in environmental impacts that are significantly different from those examined in the Business Plan EIS, and will assist BPA in accomplishing the goals related to the Market-Driven alternative that are identified in the Business Plan ROD. Therefore, the decision to implement this rate proposal is tiered to the Business Plan ROD.

PART II

WP-10 DOCKET

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4.0 LOADS AND RESOURCES

4.1 Introduction

The Loads and Resources Study, WP-10-FS-BPA-01, represents the compilation of the loads, sales, contracts, and resources data necessary for developing BPA's wholesale power rates for FY 2010-2011. Documentation supporting the results of the Loads and Resources Study is presented in the Loads and Resources Study Documentation, WP-10-FS-BPA-01A. The Loads and Resources Study is also described in the direct testimony of Hirsch, *et al.*, WP-10-FS-BPA-11.

The Loads and Resources Study and supporting documentation are used to 1) provide data to determine resource costs for the Revenue Requirement Study, WP-10-FS-BPA-02; 2) provide data to derive allocation factors for the cost of service analysis and billing determinants for rate development and the revenue forecast in the Wholesale Power Rate Development Study (WPRDS), WP-10-FS-BPA-05, and Section 7(b)(2) Rate Test Study, WP-10-FS-BPA-06; 3) provide load and resource data for use in the Risk Analysis Study, WP-10-FS-BPA-04; 4) provide regional hydro data for use in the market price forecast for the Market Price Forecast Study, WP-10-FS-BPA-03; and 5) provide system capacity data for use in the Generation Inputs Study, WP-10-FS-BPA-08.

The Loads and Resources Study includes the following related components: 1) a forecast of the Federal system load obligations, comprised of BPA's firm requirements power sales contract (PSC) obligations and other additional BPA contract obligations; 2) Federal system resource forecasts that include the output from hydro and other generating resources purchased by BPA, and other BPA contract purchases; 3) the Federal system load/resource balance, which relates Federal system sales, loads, and contract obligations to the Federal system generating resources and contract purchases; 4) total PNW regional hydro resources; and 5) forecast power purchases that are eligible for the section 4(h)(10)(C) credit.

The Loads and Resources Study will be updated for the WP-10 Final Proposal, as proposed in Staff testimony. Hirsch *et al*., WP-10-E-BPA-11, at 23-24.

4.2 Federal System Load Obligations

The Federal system load obligations forecast includes BPA's forecast firm requirement PSC obligations to public body utilities, cooperative utilities, and Federal agencies (together referred to as Public Agencies), IOUs, and DSIs; contractual obligations to the Bureau of Reclamation (Reclamation); contract obligations outside the PNW region (exports); and contractual obligations within the PNW region (intra-regional transfers-out).

To forecast utility Average System Costs and associated Residential Exchange Program benefits, BPA reviewed the total retail load and residential exchange load forecasts provided by the participating utilities in October 2008. BPA determined that these forecasts were reasonable and required no changes.

4.3 Federal System Resource Forecast

BPA markets power from generating resources that include Federal and non-Federal hydro projects, other generating projects, and other hydro-related contracts. The Federal system resource forecast includes BPA's purchased output from generating projects and other contract purchases and exchanges.

4.4 Federal System Load/Resource Balance

The Federal system load/resource balance completes BPA's load and resource picture by comparing forecast Federal system load obligations to Federal system resource output assuming 1937 water conditions for hydro resources. The result of the Federal system resources less loads is the forecast Federal system monthly firm energy surplus or deficit. On a planning basis, if BPA's annual resources are forecast to be greater than its annual load obligations under 1937 critical water conditions, BPA has firm surplus energy. Conversely, if BPA's resources are less than load obligations, BPA must purchase power or otherwise secure resources through augmentation to meet Federal system energy deficits. For the FY 2010 and FY 2011 Federal system load/resource balance, BPA incorporated its most current contract obligations, contract purchases, resources, and augmentation purchase estimates. *See* Loads and Resources Study, WP-10-FS-BPA-01, at 25-26.

4.5 Regional Hydro Resources

The Loads and Resources Study provides total PNW regional hydro resource forecasts for FY 2010-2011 as inputs into the AURORA$^{xmp®}$ electric price forecasting model for the Market Price Forecast Study, WP-10-FS-BPA-03.

4.6 Estimate of Section 4(h)(10)(C) Credit

BPA funds actions to protect, mitigate, and enhance fish and wildlife affected by Federal hydro operations, as directed by the Northwest Power Act. 16 U.S.C. §§ 839-839h. These program costs are allocated to hydro project purposes for both power and non-power uses. The Northwest Power Act includes a principle that consumers of electric power, through their rates for power services, "shall bear the costs of measures designed to deal with adverse impacts caused by the development and operation of electric power facilities and programs only." Section 4(h)(10)(C) of the Act ensures that the costs of mitigating these impacts are properly accounted for among the various purposes of the hydro projects by making sure that when BPA funds mitigation on behalf of both power and non-power project purposes, ratepayers can recoup the non-power share. BPA recoups its funding of non-power purposes through credits, known as "section 4(h)(10)(C) credits" in reference to the authorizing statutory provisions, so that ratepayers pay only the power-related share of the fish and wildlife costs. 16 U.S.C. § 839b(h)(10)(C).

BPA uses a specific methodology to determine the appropriate annual amount of section 4(h)(10)(C) credits associated with power purchases caused by fish operations. This methodology involves a comparison of two HYDSIM hydro regulation studies, one with all of the current system operating requirements and one with all of these same operating requirements except for the fish operating requirements. *See* Loads and Resources Study, WP-10-FS-BPA-01, at 28-30. In the WP-10 Initial Proposal there was an incorrect load input used in the HYDSIM study without fish operating requirements, which will be corrected for the WP-10 Final Proposal. Specifically, the incorrect load input that was used was the residual hydro load from the Loads and Resources Study, and the correct load input that will replace the incorrect input is the firm energy load carrying capability of the system without fish operating requirements. The impact of this correction will be an increase in the Final Proposal's projected 4(h)(10)(C) credit for power purchases.

4.7 Issues

Issue 1

Whether there will be a significant reduction in BPA's augmentation needs for FY 2010-2011.

Parties' Positions

NRU posits that the amount of augmentation needed in the Final Proposal will be lower than indicated in the Initial Proposal due to lower load forecasts for the load following and non-load following customers because of the current economic recession, coupled with an increase in the FY 2011 generation forecast for the Columbia Generating Station, discussed in Issue 2 below. NRU Br., WP-10-B-NR-01, at 5.

BPA Staff's Position

For the Final Proposal, BPA will to update its load obligation forecasts to reflect the current economic conditions. Hirsch *et al.*, WP-10-E-BPA-11, at 4-5. The load following and non-load following forecasts are indeed lower than those used in the Initial Proposal. These new forecasts will be used in the Final Loads and Resources Study. Staff will also include DSI load in the Final Loads and Resources Study to reflect BPA's decision on DSI service. Bliven and Lefler, WP-10-E-BPA-10, at 12; Loads and Resources Study, WP-10-E-BPA-01, at 10.

Evaluation of Positions

The augmentation included in the ratesetting process is not an exogenous amount; rather it is dependent upon the amounts of loads and resources forecast for the rate period. BPA anticipates that the load following customers' forecasts for the Final Proposal will be lower than those presented in the Initial Proposal. If updates to load following customer forecasts were the only change made to the Loads and Resources Study, augmentation needs would decline by the same amount. However, in its argument on this issue NRU has not considered other factors that may impact augmentation, such as changes in resource amounts or additional service to DSIs. Hence, the final augmentation need will be determined by all of the factors that affect augmentation amounts, not just the reduction in load following customer loads.

Note that the amount of DSI service is one factor that impacts the amount of augmentation needed. In the Initial Proposal, a total of 402 aMW of DSI service was assumed; however, only 17 aMW was reflected in the Loads and Resources Study. Loads and Resources Study, WP-10-E-BPA-01 at 10; Loads and Resources Documentation, WP-10-E-BPA-01A, Section 2.3, Tables 2.3.1 through 2.3.3. Due to time constraints surrounding the publication of the Initial Proposal, *see* section 12.1, the assumption of 385 aMW of service to the aluminum smelters and the associated amount and cost of augmentation was accounted for in the RAM Model. Wholesale Power Rate Development Study, WP-10-E-BPA-05, section 3.2.1.2.3. For the Final Proposal, the Loads and Resources Study will include BPA's final decision on the level of service to the DSIs assumed in ratemaking, as well as other updates to all load obligations and resources, and the resulting augmentation amounts.

Decision

BPA will incorporate its new forecasts for its load following, non-load following, and DSI customers for the Final Loads and Resources Study. The augmentation needs will then be calculated as the difference between the sum of BPA's load obligations and the Federal resources available to serve those obligations.

Issue 2

Whether BPA should assume a shorter duration for the planned outage of Columbia Generating Station (CGS) for its biennial maintenance in estimating the CGS generation schedule for FY 2011.

Parties' Positions

NRU states that Energy Northwest worked hard to reduce the outage at CGS in FY 2011 from 88 to 78 days. NRU Br., WP-10-B-NR-01, at 5; WP-10-B-NR-01-E01. NRU asserts that BPA should investigate whether the Energy Northwest outage plans are sound, and if the plans are sound, BPA should reduce the CGS outage accordingly. *Id*. NRU further notes that concerns about the track record for CGS outages assumptions, when compared to actual outages, could be allayed due to the fact that BPA adjusts for CGS outage length variability in its risk analysis. *Id*.

BPA Staff's Position

BPA Staff's CGS generation estimates are based on historical generating performance and incorporate refueling outage lengths and forced outages following completion of refueling outages. Loads and Resources Study, WP-10-FS-BPA-01, at 20; Hirsch *et al.*, WP-10-E-BPA-11, at 26. For FY 2011, the CGS outage will include refueling, main condenser replacement, and major upgrades to nuclear instrumentation equipment in the control room. For this significant outage, Staff estimates downtime of approximately 87 days. Loads and Resources Documentation, WP-10-FS-BPA-01, at 26, Table A-10. In addition to project shutdown time, the scheduled maintenance days include ramping time for shutdown and startup and potential forced outage time after refueling.

Evaluation of Positions

This issue of outage duration has not been formally raised on the record in this rate proceeding until NRU included the issue in its Initial Brief. NRU Br., WP-10-B-NR-01, at 5; WP-10-B-NR-01-E01. Therefore BPA's responses to this issue were set forth on the record for the first time in the Draft ROD. NRU indicates that Energy Northwest has stated it will be able to decrease the CGS outage in FY 2011 to 78 days. NRU Br., WP-10-B-NR-01, at 5; WP-10-B-NR-01-E01. However, NRU has not presented evidence in this rate proceeding as to how EN will accomplish the shortened outage. Staff's outage forecast includes project shutdown time, as well as ramping time for shutdown and startup and potential forced outage time after refueling. It is not clear if the 78-day outage schedule referred to by NRU incorporates these additional necessary maintenance days for ramping to shutdown and startup and potential forced outage time after refueling.

NRU asserts that BPA should strive to understand the feasibility of reducing the CGS outage and if the outage plans are sound, then the length of the CGS outage and amount of assumed augmentation purchases needed to provide power during the outage should be reduced accordingly. *Id*. BPA agrees that it is important that the outage forecast used in rate case analysis be based on sound outage plans and reliable evidence. BPA has reviewed all data and evidence presented on the record and is not persuaded that the outage could be decreased to 78 days. Historical performance at CGS for refueling outages for the past four maintenance refueling cycles averaged 54 days per cycle, which exceeded the forecast outage duration each cycle. The outage planned in FY 2011 is more complex than the refueling outages experienced in the past. In fact, in BPA's experience, the FY 2011 outage will be the most complex outage Energy Northwest has ever attempted. The areas of planned outage—refueling, main condenser replacement, and major upgrades to nuclear instrumentation equipment in the control room—have the potential to result in delays or increased work scope due to emergent work that is identified after the plant is shut down, during work, or during inspection activities when equipment is disassembled. With such significant changes and work scope in the plant, there is increased potential for forced shutdowns following completion of the outage. In addition, Energy Northwest does not yet have vendor bids that reflect the revised work scope for the condenser installation work. Energy Northwest will not have any such bids until the fall of 2009 at the earliest. Without bids that show that this work can be accomplished in a shortened timeframe, there is no basis to believe that the complex maintenance work will be accomplished in 78 days.

At the time the draft ROD was published, the evidence available did not provide sufficient proof that BPA's CGS maintenance outage assumption for FY 2011 should be less than the 87 days BPA assumed. WP-10-A-01 at 27-28. Nonetheless, BPA stated that it would continue to monitor the situation to determine whether a decreased maintenance outage assumption is warranted, because BPA is aware that Energy Northwest has made significant efforts to improve its budget forecast and the reliability of its outage forecasting estimates. BPA observed the recently concluded 2009 maintenance outage performance and considered the outcome of such outage in making its best estimate of the outage for the Final Loads and Resources Study. The 2009 maintenance outage was forecast by Energy Northwest to be 38 days long, but, as of July 16, 2009, the outage actually lasted for 51 days when taking into account a forced shutdown after the end of the extended refueling outage, plus an additional 7 days of reduced generation at about one-half of normal operating levels.

NRU argues that BPA's risk analysis incorporates risk associated with the length of the CGS outage, and therefore the risk analysis should allay concerns that the forecast outage may end up being an underestimate of the actual length of the outage. *Id*. NRU is correct that BPA does reflect uncertainty over the length of the CGS outage in its risk modeling. The CGS condenser replacement outage duration risk is modeled using the NORM model, which is an input into the Toolkit used in the TPP calculation in the Risk Analysis and Mitigation Study, WP-10-FS-BPA-04. The risk analysis is used to assess the risk of deviations from the most likely expectation. Therefore, even though the CGS outage length is taken into account in the risk analysis, it is important that BPA's Loads and Resources Study be based on BPA's best estimates.

Decision

BPA's best estimate of the length of CGS outage, which will be used in the Final Loads and Resources Study, is 87 days. BPA has considered all information available to it, including results of the recently concluded 2009 outage, and has not seen reliable evidence to support an outage assumption of less than 87 days.

Issue 3

Whether the increased cost of balancing purchases since the Initial Proposal is accurately calculated.

Parties' Positions

PPC *et al.* and NRU both raise questions as to why the cost of balancing purchases has increased by an average of $20 million per year since the Initial Proposal was released. PPC e*t al.* Br. Ex., WP-10-R-JP12-01, at 10; NRU Br. Ex., WP-10-R-NR-01, at 2-3. These parties note that such an outcome is counterintuitive, given that both loads and power prices have decreased since the Initial Proposal. *Id*. Parties ask that BPA re-examine the cost of balancing purchases to determine whether it can be decreased before publishing final studies. *Id*.

BPA Staff's Position

In its rebuttal testimony, Staff explained the winter hedging purchases that were made since the Initial Proposal and Staff's proposal to treat those purchases as long-term balancing purchases. Bliven *et al.*, WP-10-E-BPA-34. These purchases were made to cover increasing amounts of forecast heavy load hour (HLH) energy deficits during winter months, which potentially expose the Agency's finances to significant purchase power costs. *Id*. at 2. Parties had an opportunity to question the treatment of these winter hedging purchases as balancing purchases in their Supplemental Rebuttal Testimony due on May 1, 2009; however, no parties raised any objections.

Evaluation of Positions

The costs of power purchases and storage required to meet firm deficits on a daily and monthly basis are included in the category of balancing power purchases. Projected balancing power purchases are needed to serve firm loads in months other than the spring fish migration period, under some water conditions. The cost is the expected value of balancing power purchase costs under 70 different water conditions. Wholesale Power Rate Development Study, WP-10-E-BPA-05, at 53-54.

Based on summary data presented at a workshop open to all parties, PPC *et al.* and NRU question why the cost of balancing purchases has increased by an average of $20 million per year since the Initial Proposal was released. PPC e*t al.* Br. Ex., WP-10-R-JP12-01, at 10; NRU Br. Ex., WP-10-R-NR-01, at 2-3.

There are a number of factors that go into the computation of balancing purchase costs. In the Initial Proposal, balancing power purchase amounts and costs were determined by comparing loads and available resources for each monthly and diurnal period under each of the 70 historical water conditions. When loads exceed available resources for a period, balancing purchases are incurred and tabulated to develop the expected cost of such purchases. As explained in Staff testimony, BPA has entered into a number of purchases to hedge against potentially extreme costs of HLH winter purchases. Bliven *et al.*, WP-10-E-BPA-34, at 2.

In the numbers presented in the June 29, 2009, workshop with parties, a number of changes from the Initial Proposal were included in the cost of balancing purchases. The level of loads, the amount of resources, and the cost of the winter hedging purchases are all different from the Initial Proposal. In addition, the winter hedging purchases increase the level of secondary revenues. Therefore, the full effect of the winter hedging purchases cannot be ascertained simply by looking at the difference in balancing purchase costs between the Initial Proposal and the Final Proposal. BPA will make sure that the costs of balancing purchases and secondary revenues is accurately calculated in the Final Proposal.

Decision

BPA will ensure that the costs of balancing purchases and secondary revenues are accurately calculated in the Final Proposal.

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5.0 POWER REVENUE REQUIREMENT

5.1 Introduction

BPA's wholesale power rates are designed to recover the costs of the generation function only. The Revenue Requirement Study determines the level of revenue required to recover all costs of producing, acquiring, marketing, and conserving electric power, including the repayment of the Federal investment in hydro generation, fish and wildlife recovery, and conservation; Federal agencies' operations and maintenance expenses allocated to power; capitalized contract expenses associated with such non-Federal power suppliers as Energy Northwest; other purchase power expenses, such as system augmentation and balancing power purchases; power marketing expenses; cost to Power Services, if necessary, of purchasing transmission services; and all other generation-related costs incurred by the Administrator pursuant to law. *See* Revenue Requirement Study, WP-10-FS-BPA-02.

5.2 Revenue Requirement Development

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

The revenue requirement is developed using a cost accounting analysis comprised of the following three components.

- Repayment studies to determine the schedule of amortization payments and to project annual interest expense for bonds and appropriations that fund the Federal investment in hydro, fish and wildlife recovery, conservation, and associated assets. Repayment studies are conducted for each year of the four-year rate test period and include a 50-year repayment period.
- Operating expenses and minimum required net revenues for each year of the rate test period.
- Annual Planned Net Revenues for Risk (PNRR) based on the risks identified and quantified, the Treasury Payment Probability (TPP) standard, and other risk mitigation tools.

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

RA 6120.2 requires that BPA demonstrate the adequacy of proposed rates. The revised revenue test determines whether projected revenues from proposed rates will meet cost recovery requirements and objectives for the rate test period and repayment period. The revised revenue test demonstrates that revenues from proposed wholesale power rates will recover generation costs in the rate test period and over the ensuing 50-year repayment period. *Id*. In this proceeding, rate test period costs are demonstrated to be recovered with a very high confidence level. In the final studies, the risks are quantified and analyzed and risk mitigation measures designed to achieve a 95-percent probability that planned payments to Treasury are recovered on time and in full over the two-year rate period.

5.3 Spending Level Development

As outlined in ROD section 2.2, BPA began the Integrated Program Review (IPR) process in May 2008 with the first of a series of technical and management-level public workshops. The IPR was designed, in part, to provide an opportunity for customers and constituents to examine, understand, and provide input on program spending level projections for FY 2010-2011 for use in the Revenue Requirement Study. The participants at IPR workshops examined projected capital investments and operations and maintenance costs of the major programs that affect the calculation of wholesale power rates. The workshop topics included the projected spending levels of Columbia Generating Station, Corps of Engineers, and Bureau of Reclamation covered through direct funding agreements; conservation; renewable resources; fish and wildlife; Power Services internal operations; transmission purchases and ancillary services program; BPA corporate costs; and Federal and non-Federal debt management. In particular, the IPR included discussion of additional fish and wildlife obligations related to the Columbia Basin Accords, which BPA entered into with certain sovereign entities in 2008, and the issuance of the 2008 FCRPS Biological Opinion (BiOp).

The 2008 IPR ended with an increase of FY 2010-2011 expenses over FY 2009 levels by $100 million per year. Increases in expenses are the major reason for the rate increase indicated in the Initial Proposal.

As outlined in section 2.2, BPA revisited program spending forecasts in IPR2 after publication of the Initial Proposal to ensure that the most recent information was used in the final studies. BPA received 35 comments during the IPR2 process, ranging from support for BPA's efforts to calls for large undistributed reductions. BPA determined that it was important to take additional cost-reduction actions to reduce the proposed increase of power rates. In the IPR2 Final Report, BPA chose to reduce some of its program costs in light of the worsening economic conditions. The changes made to FY 2010-2011 program spending forecasts include a decrease of $51.4 million for Columbia Generating Station operations and maintenance costs, a $10.1 million decrease in Corps of Engineers and Bureau of Reclamation operations and maintenance costs, a decrease of $3 million in the long-term generation program, a $1.5 million decrease in conservation costs, a $1.3 million decrease in renewable resources cost, a $17.8 million decrease in internal operations, and a $15 million decrease in projected fish and wildlife spending for the rate period (deferred until future years due to project startup). These changes to program spending forecasts will be incorporated in the final studies.

5.4 Issues

Issue 1

Whether BPA should incorporate an amortization shift in the Final Proposal.

Parties' Positions

In its argument for stepped rates, Cowlitz notes in a footnote that the increase in BPA's Treasury liquidity facility is so large that it is no longer necessary to reshape amortization to avoid the effect of the Slice True-Up on PNRR. Cowlitz Br., WP-10-B-CO-01, at 2-3, fn. 1.

BPA Staff's Position

Typically, amortization shifts are performed to accommodate cash flows from revenues at proposed rates. Lennox *et al.*, WP-10-E-BPA-12, at 4. Staff intends to rerun the repayment study for the Final Proposal with multiple updates to databases to incorporate borrowing plans, new interest rate forecasts, and actual debt management actions. *Id*. at 9-10. *See* ROD section 6.2 for a discussion of the effect of the Slice True-Up on PNRR.

Evaluation of Positions

During the development of the Initial Proposal, Staff identified an unexpected and unintended cost shift from Slice customers to non-Slice preference customers because of the need to add additional PNRR to account for the forecast of a Slice True-Up Adjustment in FY 2011. Lee *et al.*, WP-10-E-BPA-21, at 7. As one method for addressing the impacts of this cost shift, $50 million of planned amortization was moved from FY 2011 to FY 2010. This shift was done without changing the total planned amortization for the rate period. Lennox *et al.*, WP-10-E-BPA-10, at 4. Subsequent to the publication of the Initial Proposal, this cost shift issue was mitigated by an increase in the Treasury liquidity facility and other changes to modeling assumptions, as described in section 6.2. As a result of the elimination of PNRR, Cowlitz states that there is no need to reshape amortization. Cowlitz Br., WP-10-B-CO-01, at 2-3, fn. 1. This statement ignores other reasons why BPA may need to reshape amortization. BPA typically shifts amortization to accommodate cash flows from revenues at proposed rates, thereby ensuring the demonstration of cost recovery. Lennox *et al.*, WP-10-E-BPA-10, at 4. Shifting amortization at the beginning of the rate development process because of the Slice True-Up was somewhat atypical but was done, in part, in anticipation of the need for a shift at the end of the process to accommodate the shape of revenues used to demonstrate cost recovery. *Id*. Eliminating the Slice cost shift issue eliminated one reason for reshaping amortization, but it does not mean that such reshaping will be unnecessary in the Final Proposal.

Decision

BPA will incorporate an amortization shift as needed to demonstrate cost recovery in the Final Proposal.

Issue 2

Whether BPA should include $100 million of undistributed cost reductions ($50 million per year of the rate period) in the Final Proposal.

Parties' Positions

WPAG proposed that BPA should assume an additional $50 million per year ($100 million for the rate period) reduction in the FY 2010-2011 revenue requirement in the form of an undistributed cost reduction that BPA would be responsible for identifying and implementing during the rate period. WPAG Br., WP-10-B-WG-01, at 7; WPAG Br. Ex., WP-10-R-WG-01, at 11.

BPA Staff's Position

BPA Staff pointed out that this is a comment on spending levels and should have been made in the IPR2 process. Lovell *et al.*, WP-10-E-BPA-48, at 7. Staff argued that when there is no reasonable prospect of achieving those reductions, it would not be consistent with sound business practices to include undistributed revenue requirement reductions for FY 2010 or FY 2011 on top of the reductions resulting from the intensive IPR2 process. *Id.* at 8.

Evaluation of Positions

WPAG's argument is not appropriate for consideration in the rate proceeding. As noted in the Federal Register Notice that published BPA's Initial Proposal, the Integrated Program Review process is separate from the rate proceeding. 74 Fed. Reg. 6609 (February 10, 2009). Thus, cost levels are not at issue in the rate proceeding. Lovell *et al.*, WP-10-E-BPA-48, at 7. By calling for "undistributed program cost reductions," WPAG Br, WP-10-B-WG-01, at 7; WPAG Br. Ex., WP-10-R-WG-01, at 11, WPAG is making an argument that should have been addressed in IPR2, which is a forum outside the ratesetting process for reviewing BPA's program spending forecasts. *See* ROD section 2.2. WPAG should have offered this proposal in the IPR2 cost review process for it to be appropriately considered. Setting aside the fact that WPAG raised this issue in the wrong forum, WPAG's proposal is not consistent with sound business practices. BPA has included undistributed cost reductions when 1) BPA concluded that additional reductions in spending levels could reasonably be accomplished, but 2) BPA had not completed identifying those reductions. Lovell *et al.*, WP-10-E-BPA-48, at 7-8. These circumstances are not present in the instant case. As noted in section 2.2 and this section 5.3, BPA recently concluded the IPR2 process, which identified in the IPR2 Final Report approximately $106 million of reductions affecting power rates for the two-year rate period. BPA has concluded that reductions can be reasonably accomplished, and, unlike the conditions noted above, has completed the identification of those reductions. To go beyond this, when there are no suggestions of where to make additional substantial reductions, and there is no reasonable prospect of achieving the reductions, would not be consistent with sound business practices. *Id.* at 8.

In addition, the call for undistributed reductions is not compatible with the need to improve or expand services, expand infrastructure, and meet reliability requirements and environmental obligations. These activities require adequate internal infrastructure. BPA cannot simultaneously pursue these needs on behalf of the region while trying to manage to artificially lowered program spending forecasts. As noted in the IPR2 closeout report cover letter, "BPA believes taking reductions in addition to the already significant reductions would jeopardize BPA's ability to meet key strategic objectives and responsibilities." *See* Revenue Requirement Study, WP-10-FS-BPA-02, Appendix A.

Finally, the increasing number of requests from BPA's customers for BPA to provide additional customer services and to address inter-customer equity issues with complex administrative solutions cannot be reconciled with a decision to institute an undistributed reduction. These requests for additional services are resulting in increases in BPA's internal operating costs. BPA cannot simultaneously pursue these requests on behalf of customers and at the same time attempt to manage to artificially lowered program spending forecasts.

Decision

BPA will not include $100 million of undistributed cost reductions ($50 million per year of the rate period) in the Final Revenue Requirement Study.

6.0 MARKET PRICE FORECAST

6.1 Introduction

The Market Price Forecast Study, WP-10-FS-BPA-03, represents the compilation of the loads, sales, contracts, and resource data necessary for developing BPA's forecasts of natural gas and electric energy market prices used in the wholesale power rates for FY 2010 and 2011. The documentation supporting the results of the Market Price Forecast Study is presented in the Market Price Forecast Documentation, WP-10-FS-BPA-03A. The Market Price Forecast Study is described in the direct testimony of Petty *et al.*, WP-10-E-BPA-13.

The electric energy market prices produced in the Market Price Forecast Study are used for 1) the secondary revenue forecast, 2) augmentation purchase costs, 3) the risk analysis, 4) the variable cost component of generation input capacity, 5) utility average system costs, and 6) rate design.

6.2 Issues

Issue 1

Whether BPA should update the Market Price Forecast for the Final Proposal.

Parties' Positions

ICNU and NRU state that BPA should set rates based on recent developments in the natural gas market. ICNU Br., WP-10-B-IN-01 at 7; NRU Br., WP-10-B-NR-01, at 4.

BPA Staff's Position

In its direct testimony, Staff states that it will update the Market Price Forecast for the Final Proposal. Petty *et al.*, WP-10-E-BPA-13, at 10. Staff outline the components of the Market Price Forecast to be updated. *Id.*

Evaluation of Positions

ICNU states that BPA's final rates should reflect that current natural gas forward prices for the rate period are not nearly as low as the current spot prices. ICNU Br., WP-10-B-IN-01, at 7. BPA agrees that current forward natural gas prices are higher than current spot natural gas prices. In fact, BPA expects natural gas prices to decrease from 2008 to 2009. Petty *et al.*, WP-10-E-BPA-13, at 3. BPA also expects natural gas prices to increase from 2009 to 2010 and 2011. *Id.*

NRU addresses the Market Price Forecast in the context of augmentation costs. NRU states that given factual developments since release of the Initial Proposal, BPA should significantly reduce the quantity and forecast price of augmentation in the revenue requirement. NRU Br., WP-10-B-NR-01, at 4. NRU further states that given the state of the regional economy and the fall-off in natural gas prices, the cost of market purchases for a flat block of power for any augmentation during the rate period should be lower than assumed in the Initial Proposal. *Id.* at 5. BPA agrees that the natural gas price forecast and thus the forecast of electric energy market prices will be lower in the Final Proposal than in the Initial Proposal. The updated Market Price Forecast is used in the Final Proposal and is one factor that contributes to the calculation of augmentation costs. However, the forecast natural gas price and forecast electric energy market prices alone do not determine the cost of augmentation in the rate case. Other factors, such as the load forecast and the amount of resources available to meet the loads, also contribute to the overall cost of augmentation. The load forecast and resource forecast are described in ROD Chapter 4.

Decision

BPA will update the Market Price Forecast for the various uses of the natural gas and electric energy market price forecasts for the Final Proposal.

7.0 RISK ANALYSIS AND MITIGATION

7.1 Introduction

BPA's business environment is filled with numerous uncertainties, and thus the ratesetting process must take into account a wide spectrum of risks. The objective of the risk analysis is to identify, model, and analyze the impacts that identified key risks and risk mitigation tools have on Power Services net revenue (total revenues less total expenses) risk and Treasury Payment Probability (TPP). This is carried out in two distinct steps: a risk analysis step, in which the distributions, or profiles, of operating and non-operating risks are defined, and a risk mitigation step, in which different risk mitigation tools are tested to assess their ability to recover power costs in the face of this uncertainty. Risk Analysis and Mitigation Study, WP-10-FS-BPA-04; Risk Analysis and Mitigation Study Documentation, WP-10-FS-BPA-04A and WP-10-FS-BPA-04B.

The impacts of operating risks are quantified through the use of the RiskMod model, and the impacts of non-operating risks are quantified through the use of the Non-Operating Risk Model (NORM). The results from the risk analysis 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 of its costs and provide a high probability of making its Treasury payments on time and in full during the rate period.

The risk analysis in the final studies includes the risk of under-recovery associated with significant amounts of self-supply of imbalance reserves by wind generators. This issue is addressed in more detail in Chapter 13, section 13.2.2, Issue 9.

7.2 RiskMod Model

The RiskMod model quantifies the impact that various Federal load, Federal resource, and wholesale spot market electricity price conditions have on BPA's net revenue. It calculates net revenue using monthly data for heavy load hour (HLH) and light load hour (LLH) electricity generation, firm loads, surplus energy sales, and power purchases. Monthly HLH and LLH energy values are calculated using load and resource data from the Loads and Resources Study, WP-10-FS-BPA-01. Monthly HLH and LLH hydro generation amounts for each of the 70 historical water years are estimated by the Hourly Operating and Scheduling Simulator (HOSS) model, which estimates the ability of the FCRPS to shape hydro generation between HLH and LLH under system operational constraints.

Net revenues are calculated using spot market electricity prices from the Market Price Forecast Study, WP-10-FS-BPA-03; various revenue data from the revenue forecast component of the Wholesale Power Rate Development Study, WP-10-FS-BPA-05; and rates and expenses from the RAM2010.

7.3 Non-Operating Risk Model

NORM is an analytical risk tool that quantifies the impacts of risks other than operating risks in the ratesetting process. It was first introduced and adopted in the WP-02 rate proceeding. NORM models the non-operating risks of Power Services and the risks of the corporate costs that are covered by Power Services. Transmission Services risks are not included in the analysis. In addition, NORM models some changes in revenue and some changes in cash. While RiskMod is used to quantify risks having to do with various economic, load, and generation resource capability variations, NORM is used to model risks surrounding projections of non-operations-related revenue or expense levels in the Power Services revenue requirement. The main NORM modules model the accrual impacts of the included risks, and an accrual-to-cash adjustment translates the net revenue impacts into cash impacts. NORM supplies 3,500 games (or iterations) of both net revenue and cash impacts. The outputs from NORM, along with the outputs from RiskMod, are input into the ToolKit model to assess the TPP.

7.4 Treasury Payment Probability

One of BPA's primary risk mitigation goals is to meet BPA's TPP standard. The TPP is the probability that a business line will have sufficient financial reserves to cover all of the scheduled payments to the Treasury that have been assigned to it during the course of a rate period, given the risks identified in the risk analysis and the available risk mitigation tools. BPA's 10-Year Financial Plan, adopted in 1993, specified that BPA shall set rates to maintain reserves sufficient to achieve a 95 percent TPP in each two-year rate period. 1993 ROD, WP-93-A-02, at 68-72. This standard was confirmed in BPA's Financial Plan Update in FY 2008. Since FY 2002, the Transmission and Power functions have set their rates separately, and BPA has determined that if each function separately meets the TPP standard with its respective rates and the reserves attributed to that business line, the Agency TPP requirement will have been met.

7.5 ToolKit

The ToolKit is an Excel 2003® spreadsheet that is used to evaluate Power Services' ability to meet the TPP standard, given the net revenue variability embodied in the distributions of operating and non-operating risks. ToolKit reads in data from two external files, one each from RiskMod and NORM.

More specifically, the ToolKit is used to assess the effects of various policies, assumptions, changes in data, and risk mitigation measures on the level of year-end reserves attributable to Power. It registers a deferral of a Treasury payment when these reserves fall below the level of "Liquidity Reserves" entered on the main page of the ToolKit. The ToolKit is run for 3,500 games. The number of those games in which each of the two years in the rate period ends with at least the level of Liquidity Reserves is divided by 3,500 to calculate the TPP. Risk Analysis and Mitigation Study, WP-10-FS-BPA-04, section 4.

7.6 Liquidity Tools

Issue 1

Whether BPA should increase rates to mitigate financial risk.

Parties' Positions

ICNU argues that BPA does not need to increase rates to mitigate financial risk. ICNU Br., WP-10-B-IN-01, at 4. ICNU contends that even if circumstances were to change such that BPA considers increasing rates to address risk, BPA should use all other available financial liquidity tools before it considers increasing rates to mitigate financial risk. *Id.* at 5. These tools include the flexible PF program, the use of transmission business line reserves, and relaxation of the 95 percent TPP standard. *Id.*

PPC *et al.* urge BPA to include all liquidity tools that reduce the cost of risk mitigation included in rates. PPC *et al.* Br., WP-10-B-JP11-01, at 2.

NRU supports the use of the additional $450 million short-term borrowing capability (referred to as short-term borrowing authority by NRU) as a liquidity tool to reduce the cost of risk mitigation included in rates. NRU Br., WP-10-B-NR-01, at 3. If the additional short-term borrowing capability is insufficient to meet BPA's liquidity needs, NRU urges BPA to pursue the Flexible PF Rate Program. *Id.* at 4, *citing* Lovell *et al.*, WP-10-E-BPA-33, at 15.

Through a participant comment, the Springfield Utility Board (SUB) also expressed support for liquidity tools that reduced the expected PF rate. Springfield Utility Board, BRCO90397, at 1. In particular, SUB requested that BPA assume the implementation of the Flexible PF Rate Agreement if the assumption would reduce BPA's risk and lower PF rates. *Id.*

NWG does not support the use of BPA transmission reserves to reduce the cost of risk mitigation included in rates. NWG Br., WP-10-B-NG-01, at 39-40. NWG argues that the use of transmission reserves for the purpose of lowering the expected power rate increase is not a principled policy and is not financially sustainable. *Id.* at 39.

BPA Staff's Position

In addition to PNRR, there are three risk tools that are reasonable to consider in an effort to reduce the cost of risk mitigation reflected in rates. The three tools are the Flexible PF Rate Program, the temporary availability of reserves attributed to Transmission, and an expansion of an agreement BPA has with the U.S. Treasury allowing for a short-term liquidity facility to pay for current expenses. Lovell *et al.*, WP-10-E-BPA-33, at 12-13.

Staff does not see the need to rely on either an interfunctional loan or the renewal of the Flexible PF Rate Program. Lovell *et al.*, WP-10-E-BPA-48, at 5. It is likely that the cost of risk mitigation reflected in rates will be so low that the addition of the use of Transmission reserves or the Flexible PF Rate Program would not change the level of rates significantly, if at all. *Id.* However, if Planned Net Revenues for Risk (PNRR) are needed, Staff recommends that the Administrator consider an interfunctional loan or renewal of the Flexible PF Rate Program. *Id.*

Evaluation of Positions

The arguments that BPA should not raise rates to mitigate risk and that BPA should not use reserves attributed to Transmission to mitigate Power risk are made moot by the calculation of rates. Based on the decision in this ROD, there will be no cost of risk in the base rates because there will be no PNRR. Contrary to the implication of ICNU's statements in its brief, the use of reserves attributed to Transmission cannot reduce a zero cost of risk, and therefore there would be no benefit to such use.

Decision

BPA's Power risk mitigation will not rely on liquidity other than reserves available for risk attributed to Power and the recently expanded portion of the Treasury note.

7.7 The Cost Recovery Adjustment Clause

Issue 1

Whether the allocation of the CRAC and DDC should be based on cost causation.

Parties' Positions

OPUC recommends that BPA engage in a more rigorous analysis than contemplated by the Initial Proposal before allocating a CRAC. OPUC Br., WP-10-B-PU-01, at 11. OPUC recommends that BPA should allocate CRAC to the Residential Exchange Program (REP) based upon the circumstances precipitating the CRAC. *Id*. OPUC asserts that when implementing a CRAC, BPA should revise REP benefits to reflect the difference in the REP benefits ordered in this proceeding and those obtained under the supplemental analysis conducted in the proceeding to implement the CRAC, and proportioned by the ratio of the months remaining after implementation of the CRAC and the 24 months of the initial rate period. *Id*.

The IOUs argue that the actual causes of a CRAC can and should be used to allocate the CRAC. IOU Br., WP-10-B-JP1-01, at 89.

BPA Staff's Position

The OPUC proposed allocation method is more complex and would not lead to a simple rule for allocation of the CRAC, as the OPUC itself points out. Brodie *et al.*, WP-10-BPA-35, at 8. The OPUC method would require tracking every cost and revenue. *Id*. Such a method would not necessarily be superior to the current method. *Id*. at 9.

Evaluation of Positions

Parties do not demonstrate that BPA's proposed method is flawed, but instead speculate that a more complex method might be superior. The requirement to track every cost event and revenue event would amount to adopting a true-up approach for risk mitigation for non-Slice rates. This would be a fundamental change in the risk mitigation approach BPA has used for rates other than Slice since the 10-Year Financial Plan was adopted in the 1993 rate case. The speculation of "superior" results of an unspecified nature is insufficient to justify a change of this magnitude, complexity, and potentially, administrative time and cost.

Decision

BPA will not base the allocation of CRAC and DDC amounts on cost causation.

Issue 2

Whether BPA has correctly accounted for the Slice True-Up Adjustment in the allocation of the CRAC and DDC.

Parties' Positions

The IOUs state that BPA should calculate the percentage of the revenue required by a CRAC necessary to address decreased net revenues borne by both Slice and non-Slice customers that should be recovered through reduced REP benefits. IOU Br., WP-10-B-JP1-01, at 88. The IOUs state that BPA would fail to account for the contribution by Slice True-Up Adjustment when calculating the CRAC adjustment for both non-Slice and REP benefits. *Id*. They propose two different solutions: a more complex cost causation proposal and a simpler one that adjusts the Accumulated Minimum Net Revenue figure to be used in the CRAC or DDC calculation for the forecast impact of the Slice True-Up. *Id*. at 89-90.

During oral argument, the IOUs illustrated their point with an example. Kari, Oral Tr. at 198. Suppose "[t]here's a significantly increased amount of federal hydro system O&M in a year that triggers a CRAC. Bonneville says, okay, we're going to collect 27 percent of that amount from reduced REP benefits and we're going to collect 85 [*sic*] percent from applying the CRAC to non-Slice rates." *Id*. "Then when BPA collects from the Slice customers next year via the true-up there is an over-collection." *Id*.

BPA Staff's Position

This issue was first raised by the IOUs in their rebuttal testimony, and BPA Staff did not have the opportunity to respond on the record.

Evaluation of Positions

The overall approach to risk mitigation BPA has adopted for use with the Slice rate is fundamentally different from the approach to risk mitigation BPA has adopted for use with non-Slice rates. This makes it essentially meaningless to compare the risk mitigation consequences of specific risks, *i.e.*, particular possible events that would have financial consequences for BPA. The Slice True-Up Adjustment responds specifically to each factor that can be trued up that turns out to be different from the value used in the rate case. The risk mitigation approach for non-Slice rates responds only to aggregate impacts of risks, not to the impacts of individual risks. The aggregate impacts of risks on reserves are used to calculate TPP and therefore PNRR during rate cases; after the conclusion of a rate case, further aggregate changes to reserves can result in the triggering of a CRAC or DDC.

The IOU example needs to be corrected. The percentage of a CRAC allocated to non-Slice PF and IP rates was 80.5 percent, not 85 percent. General Rate Schedule Provisions, WP-10-E-BPA-07, at 77. (The Final Studies will update this percentage slightly.) The amount that is allocated among REP benefits and non-Slice rates would not be the amount of the hydro system O&M increase, but 77.4 percent of it, as described next. The GRSPs describe a calculation for the CRAC and DDC that includes an explicit adjustment for the effect of the anticipated Slice True-Up Adjustment on Modified Net Revenues (MNR), and therefore on Accumulated Modified Net Revenues (AMNR), prior to calculating CRAC or DDC amounts. This adjustment has been part of the CRAC and DDC calculations since the inception of Slice in FY 2002. (*See*, *e.g.*, 2002 Final ROD, WP-02-A-09, Appendix at 21.)

Suppose a fiscal year with financial results that would trigger a CRAC in the following year. Suppose also that the hydro system O&M for that same fiscal year increases by $100 million. Several calculations ensue. The first is that MNR for that year will be reduced by $100 million due to this O&M increase. The second is the incorporation of the Slice True-Up Adjustment: 22.6 percent of this amount will be "charged" to the Slice customers through the True-Up, and the CRAC calculations will note this, adding $22.6 million to MNR for the year. This results in a *net* decrease in MNR of $77.4 million due to the O&M increase. Of this amount, 27 percent is allocated to reductions in REP benefits (for both IOU and COU exchanging customers), and 80.5 percent is allocated to non-Slice rates (non-Slice PF and IP rates). The net is that 0.27 × $77.4 million = $20.9 million of the O&M increase, or 20.9 percent, will be allocated to IOU and COU REP benefits. If an event that increased a CRAC amount were of a type not included in the Slice True-Up Adjustment, then there would not be an MNR adjustment in the CRAC calculations for the impact on the True-Up of the event; the CRAC calculations automatically distinguish between precipitating events that are and that are not paid for in part by Slice customers.

BPA's CRAC and DDC calculations treat Slice and non-Slice rates equitably, and in fact include one of the two alternative solutions recommended by the Parties. No additional action is required.

<u>Decision</u>

BPA's CRAC and DDC calculations and allocation correctly account for the Slice True-Up Adjustment.

7.8 <u>Real-Time Crediting of Secondary Revenues</u>

<u>Issue 1</u>

Whether BPA should implement real-time crediting of secondary revenues.

<u>Parties' Positions</u>

In testimony, WPAG proposes the adoption of a real-time secondary energy crediting mechanism. Saleba *et al.*, WP-10-E-WG-03, at 17-26. In its brief, WPAG modified its position and stated that it does not support the implementation of real-time crediting of secondary revenues. WPAG Br., WP-10-B-WG-01, at 12-13. WPAG observes that BPA views real-time crediting of secondary revenues as a proposal worthy of further consideration after the WP-10 proceeding has concluded. *Id., citing* Lovell *et al.*, WP-10-E-BPA-48, at 9. WPAG agrees with BPA that there is insufficient time in the WP-10 proceeding to implement real-time crediting of secondary revenues. *Id*.

NRU states that it does not support the implementation of real-time crediting of secondary revenues. NRU Br., WP-10-B-NR-01, at 7-8. NRU states that it did not have a chance to respond to WPAG's suggestions and thus supports Staff's rejection of the real-time secondary energy credit concept proposed by WPAG. *Id*. at 7.

BPA Staff's Position

There is no time available in the WP-10 proceeding to address the substantial changes that real-time crediting would entail for BPA's power rates. Lovell *et al.*, WP-10-E-BPA-48, at 9. Staff looks forward to further discussions of this idea after the conclusion of the WP-10 proceeding. *Id*.

Evaluation of Positions

Section 1010.13(b) of BPA's Rules of Procedure Governing rate hearings states that "[p]arties whose briefs do not raise and fully develop their positions on any issue shall be deemed to take no position on such issue. Arguments not raised are deemed to be waived." No party argued in brief that BPA should implement real-time crediting of secondary revenues in this rate period.

Decision

No party argued in brief that BPA should implement real-time crediting of secondary revenues in the WP-10 rate proceeding; therefore, the issue will not be addressed.

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8.0 COST OF SERVICE ANALYSIS AND RATE ANALYSIS MODEL

8.1 Introduction

BPA uses three major ratemaking steps to complete the process of determining BPA's total cost of service for power rates: 1) *functionalization* of costs between generation and transmission to develop the generation revenue requirement; 2) *allocation* of costs to classes of service in the cost of service analysis (COSA); and 3) *rate directives and rate design* to determine the rates. Steps 2 and 3, which determine the costs to be recovered by each of BPA's wholesale power rates, are performed within the Rates Analysis Model (RAM). The cost of service analysis assigns responsibility for BPA's power revenue requirement for the rate period, determined in the Revenue Requirement Study, to the various classes of service in accordance with generally accepted ratemaking principles and in compliance with statutory directives governing BPA's ratemaking.

The COSA first groups parts of the power revenue requirement into cost pools specified by section 7 of the Northwest Power Act. 16 U.S.C. § 839e. The cost pools are associated with resource pools (Federal base system (FBS) resources, exchange resources, and new resources) and costs allocated according to section 7(g) of the Northwest Power Act. 16 U.S.C. § 839e(g). The COSA then apportions or "allocates" the cost pools among classes of service (also known as rate pools) based on the priorities of service from resource pools to rate pools provided in section 7 of the Act and generally on the principle of cost causation when section 7 does not provide guidance. The relative use of resources, services, and facilities among customer classes is identified, and costs are allocated to customer classes in proportion to each class's use.

The rate design portion of RAM carries out a series of statutory adjustments, applies rate designs, and performs a Slice product separation. First, secondary and other revenues are credited to the rate pools. Next, the difference between costs allocated to firm, fixed-rate power contracts is calculated and allocated to other rate pools. Next, section 7(c), which specifies the determination of the level of the rate for sales to DSIs, is applied through a reallocation of costs. Then the section 7(b)(2) rate test (*see* Chapter 10 of this ROD) is performed and costs are reallocated depending on the outcome of the rate test. The outcome of the rate test may also result in another determination of the costs to be recovered from the DSIs. Next, the costs allocated to the Priority Firm Power (PF) Preference rate pool are adjusted to account for preference customer sales pursuant to the Slice product and sales to other preference customers. Finally, specific rate designs are applied to recover the costs allocated to each rate pool through energy, demand, and load variance rates.

The subsections that follow review the issues that were raised by rate case parties in their briefs concerning the allocation of costs to classes of service and the sequencing of the statutory rate adjustments in the development of BPA's FY 2010-2011 power rates.

8.2 Allocation of the Section 7(c)(2) Delta to Surplus Sales

Issue

Whether BPA should include surplus sales in the allocation of the section 7(c)(2) Delta.

Parties' Positions

The IOUs argue that BPA's failure to allocate the 7(c)(2) Delta to surplus sales has not been justified by BPA and is inequitable. IOU Br., WP-10-B-JP1-01, at 55-57. The IOUs claim that there is no reason that surplus sales should not bear a share of the difference between the revenues BPA expects to recover from the DSIs at the initial Industrial Firm Power (IP) rate and the costs allocated to the DSIs. *Id*.

BPA Staff's Position

Neither section 7(g) nor section 7(c)(2) of the Northwest Power Act requires that the 7(c)(2) Delta be allocated to load served under the FPS rate. Brodie *et al.*, WP-10-E-BPA-35, at 4. This is in contrast to the language in section 7(b)(3) of the Act, which requires that the 7(b)(3) supplemental rate charge be applied to *all other power* sold by the Administrator. *Id*. The 7(c)(2) Delta is not a supplemental rate charge and is not required to be allocated to all other power sold by the Administrator. *Id*.

Evaluation of Positions

As directed by section 7 of the Northwest Power Act, BPA allocates the costs of its resource pools (FBS, exchange, and new resources) to the rate pools (7(b) loads—PF rate, 7(c) loads—IP rate, and 7(f) loads—New Resources Firm Power (NR) and Firm Power Products and Services (FPS) rates) using a particular hierarchy of service to load. 16 U.S.C. § 839e. Pursuant to section 7(b)(1) of the Act, the FBS resource costs are allocated to the 7(b) rate pool first, and then exchange resource costs are allocated to the 7(b) rate pool as needed. In the instant rate case, IP, NR, and FPS rate classes are allocated the remaining exchange resource costs and then new resources costs. This initial allocation of costs results in a preliminary unbifurcated PF rate and a preliminary NR rate, as well as initial costs to be recovered from FPS contract sales and pre-statutorily determined costs from the DSIs. After reallocating costs among the rate pools to balance the costs allocated to FPS contract sales with revenues from such sales, BPA calculates an IP rate revenue requirement equal to the revenues that would be generated by an IP rate that equals the preliminary unbifurcated PF rate plus the typical margins included by consumer-owned utilities (COUs) in their retail industrial rates (established pursuant to section 7(c)(2)), minus a value of reserves (VOR) credit (established pursuant to section 7(c)(3)). The pre-statutorily determined costs initially allocated to the DSIs minus the IP rate revenue requirement calculated as described above (preliminary unbifurcated PF rate plus typical margin minus VOR credit) is the "7(c)(2) Delta." The next step is a "7(c)(2) Adjustment," by which BPA allocates the 7(c)(2) Delta to the preliminary unbifurcated PF rate and the NR rate. No allocation of a *pro rata* share of the 7(c)(2) Delta is made to surplus sales (*e.g.*, FPS contract sales, FPS surplus sales, and delivery of surplus power pursuant to the Slice product). *See* section 12.2 for a more in-depth discussion of section 7(c) and the establishment of the IP rate. *See* section 8.4 for more on the delivery of surplus power pursuant to the Slice product.

The IOUs argue that BPA's allocation of the 7(c)(2) Delta solely to the preliminary unbifurcated PF rate and the NR rate is unjustified. IOU Br., WP-10-B-JP1-01, at 56. The IOUs argue that allocation of a *pro rata* share of the 7(c)(2) Delta to surplus sales would be consistent with the Wholesale Power Rate Development Study (WPRDS), which states:

> The 7(c)(2) adjustment is necessary to account for the difference between the revenues BPA expects to recover from the DSIs at the initial IP rate and the costs allocated to the DSIs. This difference, known as the 7(c)(2) delta, is allocated to non-DSI customers, primarily the PF customers.

Id., *quoting* WPRDS, WP-10-E-BPA-05, at page 67.

In the foregoing quotation, however, the IOUs have stated just a portion of the relevant paragraph. The full paragraph shows why allocating the 7(c)(2) Delta solely to the preliminary unbifurcated PF rate and the NR rate is justified:

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

WPRDS, WP-10-E-BPA-05, at 67 (emphasis added).

Prior to the 7(c)(2) Delta adjustment, under the initial allocation of resource costs described above, more expensive exchange and new resources costs are allocated to the FPS surplus contract sales, resulting in an initial FPS rate pool revenue requirement that is greater than the forecast revenues from those sales. The Final Proposal shows that, in the FY 2010-2011 rate period, revenue of $256.9 million is forecast from the sale of firm power in various Pacific Northwest and Southwest markets. The Final Proposal allocates $688.8 million in power costs to this firm power. Therefore, there is a revenue deficiency of $431.9 million over the two-year rate period. This revenue deficiency is allocated to all other firm power (PF, IP, and NR) rates that are being adjusted in this proceeding. Final WPRDS Documentation, WP-10-FS-BPA-05A, Table 2.5.4 (RDS 17).

The Firm Power Revenue Deficiencies Adjustment described in the previous paragraph adjusts the PF, IP, and NR revenue requirements just prior to the 7(c)(2) Delta adjustment and also sets the FPS contract revenue requirement to be equal to the expected revenues from such contracts. Therefore, the 7(c)(2) adjustment should adjust only the PF, IP, and NR revenue requirements, because any increase in the FPS contract revenue requirement caused by the 7(c)(2) Delta adjustment would create an FPS rate pool revenue deficiency and would require an additional Firm Power Revenue Deficiencies Adjustment, thereby changing the PF rate and requiring another 7(c)(2) Delta calculation. Adding a circular process between the 7(c)(2) Delta adjustment and a second Firm Power Revenue Deficiencies Adjustment would then create another allocation to the PF rate, creating a third 7(c)(2) Delta calculation, and so forth, continuing *ad infinitum*. This is an unreasonable ratemaking complication that would not change the fact that, in the Final Proposal, BPA expects to recover $256.9 million from FPS contract sales in the FY 2010-2011 rate period, and recovering any resulting deficiency from the same customers that are paying for the revenue deficiency under BPA's methodology. *Id*.

The IOUs argue that BPA's failure to allocate the 7(c)(2) Delta to surplus sales has not been justified by BPA and is inequitable—there is no reason that surplus sales should not bear a share of the difference between the revenues BPA expects to recover from the DSIs at the initial IP rate and the costs allocated to the DSIs. IOU Br., WP-10-B-JP1-01, at 56. As discussed above, however, prior to the 7(c)(2) Delta adjustment, the FPS contract load allocated costs are set equal to the expected revenues to be recovered from that load through the Power Revenue Deficiencies Adjustment. WPRDS Documentation, WP-10-E-BPA-05A, Table 2.5.4 (RDS 17). Logically, even if BPA were to allocate a portion of the 7(c)(2) Delta to the FPS contract load rather than to the PF and NR rate pools, that portion of the 7(c)(2) Delta would need to be reallocated away from the FPS rate pool in order to maintain the revenue recovery mandated by section 7(a)(1) of the Northwest Power Act. 16 U.S.C. § 839e(a)(1). The only other appropriate loads are the PF and NR loads.

FPS rates are subject to section 7(f) of the Northwest Power Act, which states that:

> Rates 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 Federal base system resources, purchases of power under section [5](c) of this title and additional resources which, in the determination of the Administrator, are applicable to such sales.

16 U.S.C. § 839e(f). FPS rates are further subject to costs allocated under section 7(g), which states in pertinent part:

> Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on December 5, 1980, or by other provisions of this section, the Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this chapter, all costs and benefits not otherwise allocated under this section, including, but not limited to, … the sale of or inability to sell excess electric power.

16 U.S.C. § 839e(g).

The statutory direction for the allocation of costs to sales at FPS rates allows BPA to determine, first, which resource costs are allocable to FPS sales and, second, which other costs are allocable to FPS sales. The 7(c)(2) Delta is not a resource cost allocable pursuant to section 7(f), and section 7(c) provides no direction for the allocation of the cost differential it creates; therefore, the 7(c)(2) Delta is allocated pursuant to section 7(g). Section 7(g) directs the Administrator to equitably allocate costs to power rates in accordance with generally accepted ratemaking principles and the provisions of the Act. As discussed herein, the provisions of section 7 do not discuss the allocation of the 7(c)(2) Delta. Therefore, the remaining direction is that the Administrator shall equitably allocate costs to power rates in accordance with generally accepted ratemaking principles. This language grants the Administrator discretion in the allocation of the costs of the 7(c)(2) Delta. Allocating the 7(c)(2) Delta on the basis of firm power sold at adjustable rates is a reasonable and equitable basis.

The IOUs argue that Staff's rebuttal testimony attempts to defend its failure to allocate a *pro rata* share of the 7(c)(2) Delta to surplus sales by arguing that the 7(c)(2) Delta is not a supplemental rate charge and is not required to be allocated to all firm power sold by the Administrator:

> It is our understanding that neither section 7(g) nor section 7(c)(2) requires that the 7(c)(2) Delta be allocated to load served under the FPS rate. This is in contrast to the language in section 7(b)(3), which requires that the 7(b)(3) supplemental rate charge be applied to *all* firm load served by the Administrator. The 7(c)(2) Delta is not a supplemental rate charge and is not required to be allocated to all firm power sold by the Administrator.

IOU Br., WP-10-B-JP1-01, at 56-57, *quoting* Brodie *et al.*, WP-10-E-BPA-35, at 4.

The IOUs state that BPA's argument does not justify BPA's failure to allocate a *pro rata* share of the 7(c)(2) Delta to surplus sales. *Id.* at 57. The passage within Staff's rebuttal testimony cited by the IOUs above, however, is only part of Staff's testimony. The complete passage follows:

> We disagree with the IOUs' argument that BPA's allocation of the 7(c)(2) Delta is incorrect and that the Delta should be allocated *pro rata* to all non-DSI loads. It is not true that allocation of the 7(c)(2) Delta is controlled by section 7(g) of the Northwest Power Act. Even if we were to accept that premise *arguendo*, section 7(g) still provides the Administrator the flexibility to "equitably allocate" the Delta; section 7(g) does not require *pro rata* allocation over all firm loads.
>
> At the point in BPA's ratemaking of allocating the 7(c)(2) Delta, the unbifurcated Priority Firm rate pool contains all firm PF Preference load (including the PF Slice product load) and all PF Exchange load. It is our understanding that neither section 7(g) nor section 7(c)(2) requires that the 7(c)(2) Delta be allocated to load served under the FPS rate. This is in contrast to the language in section 7(b)(3), which requires that the 7(b)(3) supplemental rate charge be applied to *all* [other power sold] by the Administrator. The 7(c)(2) Delta is not a supplemental rate charge and is not required to be allocated to all [other] power sold by the Administrator. Since 1985, BPA has interpreted and implemented section 7(c)(2) so that the IP rate is set based on specific relationships of the IP rate to the PF and NR rates. The 7(c)(2) Delta and its subsequent allocation constitute the rate adjustment used to adjust the level of the IP, PF, and NR rates so that they have the proper relationships to each other. As such, the allocations are made to rates whose levels are implicated by section 7(c)(2): the PF, IP, and NR rates.

Brodie *et al.*, WP-10-E-BPA-35, at 4-5.

Staff's statement that it "is not true that allocation of the 7(c)(2) Delta is controlled by section 7(g) of the Northwest Power Act" is incorrect. Section 7(g) does assist in determining the allocation of the 7(c)(2) Delta, as discussed above. With this adjustment, however, Staff's analysis is sound.

For the foregoing reasons, BPA continues to believe that BPA's current treatment for the 7(c)(2) Delta is proper and reasonable. Further, this treatment has been unchanged since 1985.

Decision

BPA will not allocate a portion of the 7(c)(2) Delta to BPA's surplus sales.

8.3 Section 7(b)(3) and the Irrigation Rate Mitigation Product (IRMP)

Issue

Whether BPA should include an allocation of the section 7(b)(3) trigger amount to IRMP sales.

Parties' Positions

The IOUs argue that part of the 7(b)(3) trigger amount should be allocated to IRMP sales. IOU Br., WP-10-B-JP1-01, at 68. The IOUs also state that, if BPA fails to allocate section 7(b)(3) trigger amounts to IRMP sales, then BPA must, in any event, recover revenue reductions associated with IRMP sales solely from the PF Preference rate customer class. *Id.* The IOUs argued that IRMP sales, in addition to the 7(b)(3) allocation, should be included in the 7(b)(2) Case general requirements. *Id.* However, in the IOUs' Brief on Exceptions, the IOUs clarify their Initial Brief by stating that their argument that the IRMP sales should be included in the 7(b)(2) general requirements was a misstatement. Rather, the IOUs state they meant to argue that IRMP sales should be served in the 7(b)(2) Case with available FBS resources in the same manner as Pre-Subscription sales. IOU Br. Ex., WP-10-R-JP1-01, at 22.

Cowlitz argues that the IRMP sales cannot simultaneously be "general requirements" in the 7(b)(2) Case and sales to which the section 7(b)(3) trigger amounts are assigned. Cowlitz claims that BPA's inconsistent treatment of such sales is plainly unlawful. Cowlitz Br. Ex., WP-10-R-CO-01, at 6. Cowlitz states that because the IRMP sales are fixed price sales, it is not possible to impose a Supplemental Rate Charge on IRMP sales. *Id.* at 4. Instead, Cowlitz asserts, BPA will simply reduce the secondary revenue credit for PF rates, thus increasing the PF Preference rate. *Id.* Cowlitz believes this "sham recovery" is a plain violation of sections 7(b)(2) and 7(b)(3). *Id.*

PPC *et al.* express a similar view. PPC *et al.* argue that BPA has created an irreconcilable mismatch by maintaining IRMP loads as requirements loads in the rate test while at the same time allocating section 7(b)(3) trigger amounts to the IRMP sales as surplus sales. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 9.

NRU objects to BPA's decision to allocate section 7(b)(3) trigger amounts to IRMP sales on the grounds that parties have not had an adequate opportunity to respond to BPA's decision. NRU Br. Ex., WP-10-R-NR-01, at 6-7. NRU argues that it has not had the opportunity to fully understand from BPA how the draft decision affects rates to its irrigating utility members or to test alternative approaches to the proposed allocation. *Id. at 9.*

PNGC argues that BPA has improperly assumed that IRMP sales are surplus sales. PNGC Br. Ex., WP-10-R-PN-01, at 5. PNGC notes that BPA decided for good policy reasons to apply a discount to the applicable PF rate under the label of an FPS sale. *Id.* PNGC also argues that BPA's manual adjustment to the allocation of the section 7(b)(3) trigger amounts, while solving BPA's practical problem, is not correctly treated in the 7(b)(2) calculation. *Id.*

<u>BPA Staff's Position</u>

BPA Staff modeled the IRMP as firm requirements sales because IRMP customers were historically (and continue to be) public body customers whose power requirements were (and are) generally met with section 5(b) sales. Brodie *et al.*, WP-10-E-BPA-35, at 9. Staff did not discuss, and no party argued in testimony, that IRMP sales should be allocated section 7(b)(3) trigger amounts.

<u>Evaluation of Positions</u>

As an adjunct to its Subscription contracts with consumer-owned utilities, BPA offered surplus power sales contracts under the FPS rate schedule to mitigate inordinate rate impacts on certain groups of customers. Power Subscription Strategy Administrator's ROD, December 1998, at 25-27. When the contracts were offered, BPA anticipated certain rate design changes for the FY 2002-2006 rate period that would result in significantly increased demand charges and summer seasonal rates compared to 1996 rate levels. BPA concluded that it was appropriate to address the potential inordinate impact of rate design changes on utilities. WP-02 Wholesale Power Rate ROD, WP-02-A-02, at 10-3. BPA offered FPS contracts to small rural full service customers with heavy irrigation load where rate design changes had inordinate effects on such customers. These FPS contracts are for the sale of the Irrigation Rate Mitigation Product.

The loads in the RAM include approximately 196 aMW of IRMP sales. Brodie *et al.*, WP-10-E-BPA-35, at 9. These IRMP sales are sales to preference customers under the FPS rate schedule at rates calculated as a discount from PF rates. *Id.* In RAM, these sales are included in the preference customer loads, with a corresponding net cost of the rate discount included in the revenue requirement. *Id.* Table 2.1 in the Loads and Resources Study, WP-10-E-BPA-01, reflects those loads that will be subject to PF rates and therefore does not include the IRMP amounts. *Id.*

IRMP sales have been included as PF Preference load for ratemaking purposes. Brodie *et al.*, WP-10-E-BPA-35, at 10. As a factual matter, preference loads currently served by IRMP sales were previously served by PF Preference sales. *Id.* IRMP sales were converted to surplus sales under section 5(f) of the Northwest Power Act, and not requirements sales under section 5(b), only as a rate accommodation to IRMP customers. *Id.* Indeed, the contract rates for IRMP sales are calculated as a contractually stated discount to the PF Preference rate. *Id.* BPA uses the FPS rate established under section 7(f) of the Act to provide such customers with rate reductions through special rate design features. *Id.* The IRMP provides only a portion of the BPA power sold to irrigation customers. *Id.* IRMP customers were historically (and continue to be) public body customers whose power requirements were (and are) generally met with section 5(b) sales. *Id.* In order to make a proper comparison of the costs of power to public body customers in the

Program and 7(b)(2) Cases, the total loads of the public body customers should be reflected in both Cases. *Id.*

In their Initial Brief, the IOUs argue that IRMP sales are sales under the FPS rate schedule and must be allocated section 7(b)(3) trigger amounts. IOU Br., WP-10-B-JP1-01, at 68. The IOUs state that power sales under the FPS rate include, for example, BPA's Pre-Subscription Contract power sales. *Id.* The IOUs note that BPA allocates section 7(b)(3) trigger amounts to all FPS contract sales in determining the secondary revenue credit. *Id.* The IOUs question BPA's decision to treat IRMP sales differently from all other FPS contract sales with respect to allocation of section 7(b)(3) trigger amounts. *Id.* To be consistent with BPA's treatment of other FPS contract sales, including Pre-Subscription sales, the IOUs contend that IRMP sales should be allocated section 7(b)(3) trigger amounts. *Id.*

In response, BPA states in the Draft ROD that Staff did not address in testimony whether IRMP sales should receive an allocation of the section 7(b)(3) trigger amount. Draft ROD, WP-10-A-01, at 51; *see also* Brodie *et al.*, WP-10-E-BPA-35, at 9-10. BPA also notes that this issue was not raised during the evidentiary phase of the rate proceeding, and the IOUs' Initial Brief presents a matter of first impression before the agency. Draft ROD, WP-10-A-01, at 51. Although the treatment of IRMP sales was not raised during the hearing phase of the proceeding, BPA believed that addressing this issue in the Draft ROD was appropriate because it was assumed to be a purely legal question which would not have benefitted from further factual development from the record.

As a result, BPA agreed in the Draft ROD that IRMP sales should, in general, be treated in the same way as all other FPS contracts. In reaching this decision, BPA considered its prior decision in the WP-07 Supplemental ROD, where BPA found that the plain language of the Northwest Power Act requires that the section 7(b)(3) trigger amount be recovered from all non-PF Preference power sales, including surplus sales made under the FPS rate schedule. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 339. BPA reasoned that although sales to irrigators are traditionally implemented as requirements sales under section 5(b) of the Northwest Power Act, the IRMP sales were structured under BPA's authority to sell surplus power under section 5(f) of the Act. Brodie *et al.*, WP-10-E-BPA-35, at 10. Thus, BPA concluded in the Draft ROD that the IRMP sales are technically sales of power under the FPS rate schedule, and therefore, must be allocated section 7(b)(3) trigger amounts. Draft ROD, WP-10-A-01, at 53.

Although agreeing in principle with the IOUs' argument, in practice, BPA cannot adjust its ratemaking proposal to make the requested change. BPA explains in the Draft ROD that as Staff prepared to make the foregoing adjustment to RAM, Staff encountered a number of modeling difficulties. Draft ROD, WP-10-A-01, at 51. As noted in Staff's testimony, the IRMP sales have been modeled as part of the preference customers' general requirements for purposes of setting the PF rate. Brodie *et al.*, WP-10-E-BPA-35, at 10. To allocate section 7(b)(3) trigger amounts to IRMP sales, BPA would have to remove the loads associated with the IRMP sales from the general requirements of the preference customers and include them as FPS sales. Because the IRMP rate is tied to the PF rate, a new rate algorithm would need to be developed to account for such relationship. Introducing such an algorithm in a limited amount of time could easily introduce other errors into the RAM. Further, making this change now would require significant modification of several other rate case studies, such as the Loads and Resources Study, Revenue Requirement Study, and Section 7(b)(2) Rate Test Study. BPA states in the Draft ROD that it is concerned that if these changes were attempted at this stage in the rate proceeding, BPA's final rate proposal would not be complete and ready to file with the Commission by the end of July.

As an alternative to separately stating IRMP sales in the RAM as FPS sales and thereby directly allocating section 7(b)(3) trigger amounts to IRMP sales, BPA proposed to manually adjust the allocation factor used to assign section 7(b)(3) trigger amounts to surplus sales. Draft ROD, WP-10-A-01, at 52. Specifically, BPA proposed to add 196 aMW (plus losses) to each year's FPS allocation factor in the 7(b)(3) allocation step. *Id*. By increasing the allocation factor for FPS-related sales, the end result would have appropriately reflected, to the maximum extent possible at this stage of the rate proceeding, the effects of assigning part of the section 7(b)(3) trigger amount to IRMP sales. BPA believed at the time that this approach was the most reasonable because it allocated additional section 7(b)(3) trigger amounts to surplus sales (as argued by the IOUs) without requiring BPA to substantially revise its underlying rate case modeling. *Id*. Because the IRMP sales contracts contain specific rate provisions, it was not possible to include a 7(b)(3) Supplemental Rate Charge in the rates to IRMP sales. Therefore, the allocation of the 7(b)(3) trigger amounts to IRMP sales would have been treated in the same manner as other FPS sales with fixed contract rates, and such allocation would have reduced the secondary revenue credit.

A number of parties raised objections and concerns with BPA's draft decision to allocate section 7(b)(3) trigger amounts to IRMP sales without the other necessary modifications. Cowlitz Br. Ex., WP-10-R-CO-01, at 3-6; PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 9-10; NRU Br. Ex., WP-10-R-NR-01, at 4-9; PNGC Br. Ex., WP-10-R-PN-01, at 4-5. Several parties argue that because this issue was raised late in the rate proceeding, they have not been afforded an adequate opportunity to address the IOUs' position. NRU Br. Ex., WP-10-R-NR-01, at 4-9; PNGC Br. Ex., WP-10-R-PN-01, at 4-5. NRU argues that this issue would benefit from further factual development on the record. NRU Br. Ex., WP-10-R-NR-01, at 7-9. Specifically, NRU contends that had this issue been raised sooner in the case, parties would have had an opportunity to submit data requests, analysis, and rebuttal testimony. *Id*. at 9. NRU argues that BPA should not have made this draft decision, because NRU has not had the opportunity to fully understand how the decision affects rates to its irrigating utility members nor the chance to test alternative approaches to the proposed allocation. *Id*.

Other parties argue that BPA's draft decision to treat the IRMP sales as surplus sales is simply incorrect. PNGC, for example, argues that the IRMP sales should not be treated as surplus sales at all. PNGC Br. Ex., WP-10-R-PN-01, at 4-5. Rather, PNGC argues, in substance, these sales are general requirement sales that must be treated like other BPA preference power sales. *Id*. PNGC contends that for good reasons BPA made a policy decision to apply a discount to the applicable PF rate, document it in the IRMP contracts, and implement it under the label of an FPS sale. *Id*.

Finally, both preference customers and the IOUs identify problems with the workaround described in the Draft ROD. *See* Cowlitz Br. Ex., WP-10-R-CO-01, at 3-6; PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 9-10; PNGC Br. Ex., WP-10-R-PN-01, at 4-5. Cowlitz, PPC *et al.*, and

PNGC argue that BPA's draft decision to allocate section 7(b)(3) amounts to IRMP sales results in an irreconcilable conflict because it simultaneously treats IRMP sales as "general requirements" in the 7(b)(2) Case and sales to which the section 7(b)(3) trigger amounts are assigned. Cowlitz Br. Ex., WP-10-R-CO-01, at 3-6; PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 9-10; PNGC Br. Ex., WP-10-R-PN-01, at 4-5. These parties contend that the Northwest Power Act does not allow BPA to include IRMP sales as general requirements loads in the 7(b)(2) rate test case and, at the same time, allocate section 7(b)(3) trigger amounts to these sales as surplus sales. *Id*. The IOUs appear to agree with this aspect of the preference customers' argument. IOU Br. Ex., WP-10-R-JP1-01, at 22. Though not objecting to BPA's draft decision to increase the section 7(b)(3) allocation factors, the IOUs clarify that BPA should remove the IRMP loads from the general requirements in the section 7(b)(2) Case and treat the IRMP sales in the same manner as Pre-Subscription sales. *Id*.

After reviewing the concerns and issues raised by the parties in the Briefs on Exceptions, BPA now believes that it erred in its draft decision on this issue. At the time of publication of the Draft ROD, BPA believed that the treatment of the IRMP sales was primarily a legal question that would not have benefitted from further factual development on the record. The comments made in the parties' Briefs on Exceptions, however, convince BPA that this issue is far more complex and nuanced than BPA originally thought and should be reserved for further factual development in a future rate case. BPA will, therefore, not implement the Draft ROD's treatment of the IRMP sales. In so doing, BPA notes that it is not finally deciding the appropriate treatment of the IRMP sales and will address this issue, if necessary, in a future rate case.

BPA's decision to postpone deciding this issue is influenced by the comments raised in the parties' Briefs on Exceptions in three respects. First, the parties have raised a number of valid factual questions in their briefs that require further development in the rate case record. For example, PNGC argues that there are legitimate reasons for treating IRMP sales differently from other surplus sales. PNGC Br. Ex., WP-10-R-PN-01, at 4-5. PNGC contends that though the IRMP sales on their face appear to be surplus sales, the substance of the agreements supports their being requirement sales. *Id*. PNGC argues that BPA has articulated past justifications that support this treatment. *Id*. PNGC is correct; this is the position Staff took in the testimony that the IOUs challenge. BPA believes having further record development on these assertions from Staff and PNGC is essential to determining whether IRMP sales are not requirements sales and, therefore, should be allocated section 7(b)(3) trigger amounts.

Second, BPA is concerned that without further factual investigation, parties may be denied the opportunity to fully argue against the IOUs' position. As noted by NRU, the fact that this issue was raised for the first time in the IOUs' Initial Brief, and addressed by BPA for the first time in the Draft ROD, means that parties such as NRU have not had an opportunity to request information or suggest alternatives to the IOUs' position. NRU Br. Ex., WP-10-R-NR-01, at 4-9. Although BPA is not precluded in the Draft ROD from addressing legal issues raised for the first time in a party's brief, the factual questions raised by the preference customers suggest to BPA that this issue cannot be decided based on the paucity of material in the existing record. Rather, BPA concurs with NRU's comment that this particular issue would have been better served had it been addressed during the evidentiary phase of the proceeding where it could have been further developed through discovery and rebuttal testimony.

Third, and finally, even if BPA could have resolved the IRMP issue in this proceeding, it is unlikely that BPA could fully and properly reflect the draft decision in the final rate studies. In the Draft ROD, BPA is clear that because of the lateness of this issue, BPA cannot adjust the load treatment of the IRMP sales without substantially revising a number of key models and studies, such as the RAM, the Load and Resource Study, the Revenue Requirement Study, and the 7(b)(2) Rate Study. Draft ROD, WP-10-A-01, at 51-52. Rather than make these substantive revisions, BPA proposed a workaround that addressed the IOUs' concerns without requiring a fundamental change to BPA's underlying rate assumptions. *Id*. This "workaround," however, creates more problems than it solves. As noted by the public agency customers, BPA's proposal to change only the section 7(b)(3) allocation factors but not remove the IRMP sales from the preference customers' general requirements would create an "irreconcilable mismatch." Cowlitz Br. Ex., WP-10-R-CO-01, at 3-6; PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 9-10; PNGC Br. Ex., WP-10-R-PN-01, at 4-5. The only way to avoid this mismatch is to remove the IRMP sales from the general requirements of the preference customers. Cowlitz Br. Ex., WP-10-R-CO-01, at 5-6; PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 9. In revising their argument, the IOUs themselves highlight this flaw by suggesting that the IRMP loads be removed from the general requirements of the preference customers. IOU Br. Ex., WP-10-R-JP1-01, at 22.

Upon further review, BPA agrees that the proposed workaround described in the Draft ROD creates other unintended ratemaking problems. BPA concurs with the parties' observation that the only way to allocate section 7(b)(3) trigger amounts to IRMP sales (if BPA were to decide to make such an adjustment) would be by removing the IRMP sales from the preference customers' general requirements. BPA is not able to make this adjustment in this case, however, because it requires major revisions to most, if not all, of the final rate models and studies. Making these adjustments at this late stage would seriously jeopardize BPA's ability to finalize its rate proposal in time to receive Commission review and approval and have rates in effect for the next fiscal year. BPA attempted to avoid this problem in the Draft ROD by adopting the workaround described above. Because the workaround has been shown to be fundamentally flawed, BPA now finds that even if it concurred that IRMP sales should receive an allocation of section 7(b)(3) amounts, the prior treatment of the IRMP sales would have been maintained in this case because the IOUs did not timely raise the issue during the evidentiary phase of the proceeding, leaving insufficient time to reflect these changes in the final rate models and studies.

In summary, BPA decides in this Final Record of Decision not to adopt the IOUs' position, but instead will maintain the treatment of the IRMP sales as presented in the Initial Proposal. That is, BPA will not allocate section 7(b)(3) amounts to IRMP sales, and IRMP sales will remain included in general requirements. BPA reaches this decision because the issue of whether to allocate section 7(b)(3) amounts to IRMP sales was raised at a late stage in the case, has not been adequately addressed in the record, and would require major revisions to the models and studies, if adopted. By continuing the status quo, BPA is not expressing an opinion on the merits of this issue and will address whether to allocate section 7(b)(3) trigger amounts to IRMP sales, if necessary, in a future rate case.

In addition to the arguments described above, Cowlitz, PPC *et al.*, and NRU re-argue their prior position that BPA's decision to allocate costs to surplus sales is unlawful and inconsistent with section 7(b)(2). Cowlitz Br. Ex., WP-10-R-CO-01, at 3-6; PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 9-10; NRU Br. Ex., WP-10-R-NR-01, at 4-9. BPA has previously addressed these arguments in the WP-07 Supplemental ROD and will not repeat its responses here. *See* WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 335-368. To the extent that the parties' arguments pertain to IRMP sales, that issue is now moot.

The IOUs stated that IRMP loads, like Pre-Subscription loads, should be included in the 7(b)(2) Case general requirements. *Id*. at 70. In its Brief on Exceptions, the IOUs clarify that this statement was in error, and that BPA should not include IRMP and Pre-Subscription sales in the preference customers' general requirements. IOU Br. Ex., WP-10-R-JP1-01, at 22. Instead, the IOUs argue BPA should serve these loads with available FBS resources in the 7(b)(2) Case. *Id*. Because BPA is deferring the underlying issue, BPA will not decide this issue at this time. This issue also needs more development regarding the proper order of the application of FBS resources in the 7(b)(2) Case.

The IOUs state that if BPA fails to allocate the 7(b)(3) trigger amount to IRMP sales, then BPA must, in any event, not improperly and arbitrarily shift impacts of revenue reductions associated with the IRMP sales from PF Preference rate customers to PF Exchange rate customers. IOU Br., WP-10-B-JP1-01, at 69. The IOUs claim that BPA inappropriately shifts a significant portion of the lost revenue resulting from the IRMP to the PF Exchange rate by allocating the net cost of the IRMP to the unbifurcated PF rate. *Id*. Under this approach, both the PF Preference rate and the PF Exchange rates share the net cost of the IRMP. *Id* The IOUs argue there is no BPA stated policy or legal explanation for shifting costs from the PF Preference rate customer class to the PF Exchange rate customer class. *Id*. Only PF Preference rate customers receive, or are even eligible for, the IRMP. *Id*. Accordingly, the IOUs claim, BPA should revise the steps of RAM2010 or the PF Preference rate design as necessary to ensure that none of the revenue reduction associated with the IRMP is allocated to the PF Exchange rate customer class. *Id*. Indeed, the IOUs state, BPA could recognize the IRMP sales as part of the final step in designing the (non-Slice) PF Preference rate in a manner that would recover the revenue reduction associated with the IRMP sales from within the PF Preference rate class. *Id*.

The IOUs' argument is not persuasive. In essence, the IOUs argue that the revenue reduction associated with the IRMP sales should not be allocated to the PF Exchange rate. IOU Initial Brief, WP-10-B-JP1-01, at 68-71. This treatment would not be proper. The revenue reduction resulting from the sale of IRMP power is properly included in the *PF rate* revenue requirement. Prior to the section 7(b)(2) rate test, there is only one PF rate class, not a PF Preference rate class and a PF Exchange rate class. The revenue reduction from IRMP sales must be included in the projected amounts to be charged preference customers when performing the section 7(b)(2) rate test. At this point in the ratesetting process, there is no distinction between the PF Preference rate and the PF Exchange rate; at this point the rate is called the unbifurcated PF rate. If the section 7(b)(2) rate test does not "trigger" and thus provides no rate protection, the two rates are identical (with the exception of a transmission adder to deliver exchange power to PF Exchange purchasers). Allocating the IRMP solely to the PF Preference rate would cause the PF Preference rate to exceed the PF Exchange rate in the case when there is no section 7(b)(2) rate protection. There is no basis to charge preference customers more than Residential Exchange Program (REP) participants when the rate for the common section 7(b)(1) rate pool is to be equal. The same logic holds even when the section 7(b)(2) rate test triggers and affords rate protection to preference customers. Simply because the section 7(b)(2) rate protection lowers the PF Preference rate and increases the PF Exchange rate does not give rise to allocating the revenue reduction of the IRMP differently from how it would be allocated in the absence of section 7(b)(2) rate protection.

Decision

The rate case record has not been sufficiently developed for BPA to reach a decision on whether to allocate section 7(b)(3) trigger amounts to IRMP sales. Additional factual development on the record is necessary for BPA to decide this issue. In addition, BPA will not assign the revenue reduction from IRMP sales solely to the PF Preference rate.

8.4 Section 7(b)(3) Supplemental Rate Charges and the Slice Rate

Issue 1

Whether BPA should allocate a section 7(b)(3) Supplemental Rate Charge to the surplus portion of BPA's Slice sales.

Parties' Positions

The Slice Customers Group argues that BPA should not allocate a portion of the 7(b)(3) trigger amount to BPA's surplus power sales, including surplus sales to Slice customers. Slice Br., WP-10-B-JP4-01, at 3-5.

BPA Staff's Position

In BPA's WP-07 Supplemental rate proceeding, Staff noted that the allocation of a portion of the 7(b)(3) trigger amount to BPA's surplus power sales, including surplus sales to Slice customers, needed to be determined based on a review of legal issues and the record. Doubleday *et al.*, WP-07-E-BPA-78, at 11. In the WP-07 Supplemental ROD, the Administrator concluded that BPA would allocate a portion of the 7(b)(3) trigger amount to BPA's surplus power sales, including Slice. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 335-368. In the instant case, Staff notes that the surplus portion of BPA's Slice sales is allocated its proper amount of 7(b)(3) rate protection costs. Brodie *et al.*, WP-10-E-BPA-35, at 3.

Evaluation of Positions

In BPA's WP-07 Supplemental rate proceeding, BPA determined that its surplus power sales, including the surplus portion of sales under the Slice rate, do not serve the general requirements of preference customers. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 339-340; *generally*, 335-368. Therefore, such sales are not afforded the rate protections under section 7(b)(2). *Id*. Only the section 7(b)(1) PF Preference rate for the general requirements of public body, cooperative, and Federal agency customers is entitled to the protection of section 7(b)(2). *Id*. Therefore, BPA's surplus sales, including the surplus portion of sales under the Slice rate, are a part of "… all other power sold by the Administrator to all customers" under section 7(b)(3). *Id.* Thus, a portion of the 7(b)(3) trigger amount can be allocated to BPA's surplus power sales, including the surplus portion of sales under the Slice rate.

The Slice Group raises the same issue that was decided in BPA's WP-07 Supplemental rate proceeding, arguing that BPA should not allocate a portion of the trigger amount to BPA's surplus power sales, particularly BPA's surplus power sales under the Slice rate. Slice Br., WP-10-B-JP4-01, at 3-5. As noted in section 1.1.5, the Standstill Agreement preserves all litigants' arguments regarding the identified issues decided in the WP-07 Supplemental rate proceeding. Thus, there was no need for the Slice Group to repeat arguments regarding this issue in its brief. The Slice Group raises no new issues on this topic in its Initial Brief, as seen by a review of such arguments.

The Slice Group argues that BPA's proposal to allocate a portion of the 7(b)(3) trigger amount to BPA's surplus sales, including the PF Slice rate, subordinates the cost protection language of section 7(b)(2) to the ministerial cost collection language of section 7(b)(3). Slice Br., WP-10-B-JP4-01, at 3, *citing* WPRDS Documentation, WP-10-E-BPA-05A, Table 2.5.9A. The Slice Group states that the BPA proposal creates a conflict between the operation of these two provisions where none exists, and defeats the very purpose of the 7(b)(2) rate test. *Id.* The Slice Group argues that statutory provisions must be interpreted in a manner that harmonizes their operation, and not in a way that creates a fundamental conflict in their operation or that renders a provision surplusage. *Id., citing* 2A Sutherland Statutory Construction, § 46.06 (5th ed. 1992).

The Slice Group claims BPA's proposal to allocate a portion of the section 7(b)(3) trigger amount to the PF Slice rate is contrary to the plain meaning of sections 7(b)(2) and (3) and violates these basic canons of statutory interpretation. *Id.* Preference customers previously raised these arguments in the WP-07 Supplemental rate proceeding. As BPA explained in the WP-07 Supplemental ROD, BPA's interpretation is consistent with the plain meaning of the statute, does not create a conflict between the statutory provisions, and is consistent with the purpose of the 7(b)(2) rate test. Although BPA harmonized the provisions of sections 7(b)(2) and 7(b)(3), the Slice Group's proposal would have been *directly contrary* to the requirement in section 7(b)(3) to allocate the trigger amount to "all other power sold by the Administrator to all customers." 16 U.S.C. § 839e(b)(3). WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 335-368. Furthermore, section 7(b)(3) of the Act is not simply a "ministerial" provision, but rather a substantive provision with the critical function of prescribing the power sales from which the trigger amount is to be recovered.

The Slice Group also argues that applying the 7(b)(3) surcharge to the surplus power sold to Slice customers will not "recover" additional revenues. Slice Br., WP-10-B-JP4-01, at 4. The Slice Group argues that it merely reallocates the cost of the 7(b)(2) rate ceiling protection back to the PF rate, including the PF Slice rate, and results in the Slice customers being unlawfully charged the costs of their own 7(b)(2) rate ceiling protection. *Id.* Preference customers previously raised this argument in the WP-07 Supplemental rate proceeding. BPA determined the argument was not convincing for the reasons stated in the WP-07 Supplemental ROD. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 335-368.

The Slice Group also argues that applying the 7(b)(3) surcharge to BPA's surplus power sales, including the surplus power sold to Slice customers, shields the REP benefits enjoyed by the IOUs from the full operation of 7(b)(2) and (3) and charges Slice and other preference customers a PF rate that exceeds the amounts that can lawfully be charged such customers under the 7(b)(2) rate ceiling test. Slice Br., WP-10-B-JP4-01, at 5. Preference customers previously raised this argument in the WP-07 Supplemental rate proceeding. BPA determined that the argument was not convincing for the reasons stated in the WP-07 Supplemental ROD. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 335-368.

Decision

In accordance with the decision in BPA's WP-07 Supplemental ROD, BPA will continue to allocate a portion of the 7(b)(3) allocation amount to BPA's surplus power sales, including surplus power sales to Slice customers.

Issue 2

Whether BPA should recover the section 7(b)(3) trigger amount allocated to the surplus portion of sales under the PF Slice rate through a 7(b)(3) Supplemental Rate Charge to the Slice rate rather than a reduction in the secondary revenue credit.

Parties' Positions

The IOUs argue that the surplus portion of sales under the Slice rate is not afforded section 7(b)(2) rate protection, and the Slice rate should include a 7(b)(3) Supplemental Rate Charge. IOU Br., WP-10-B-JP1-01, at 46-55. The IOUs state that BPA correctly concluded that the surplus portion of sales under the Slice rate is not afforded section 7(b)(2) rate protection. *Id*. at 47. The IOUs state that, under Staff's proposal, the only impact on the Slice rate from allocation of the section 7(b)(3) trigger amount to Slice surplus sales results from BPA including in the Slice rate formula the increased REP net benefits (which result from recognizing that the PF rate secondary revenue credit is reduced by the allocation of the section 7(b)(3) trigger amount to surplus power). *Id*. at 50.

The IOUs argue that this approach simply treats the Slice rate the same as the non-Slice PF Preference rate and in no way demonstrates the extent to which the secondary energy sold under the Slice rate bears any section 7(b)(3) trigger amounts. *Id*. The IOUs argue that BPA should develop supplemental rate charges to recover the section 7(b)(3) trigger amounts allocated to Slice surplus sales and add such supplemental rate charges to the rates for those sales. *Id*. at 53; IOU Br. Ex., WP-10-R-JP1-01, at 23.

In contrast, the Slice Group argues that the IOU proposal should be rejected for four primary reasons: 1) it would result in an inequitable and unlawful double allocation of 7(b)(3) trigger amounts to Slice customers; 2) it would require the unlawful imposition of a 7(b)(3) surcharge directly on the PF Slice rate, which is statutorily protected from such surcharges; 3) it would result in large disparities in the 7(b)(3) trigger amounts paid by individual Slice customers; and 4) it would result in a windfall increase in REP benefits. Slice Br., WP-10-B-JP4-01, at 3.

BPA Staff's Position

The surplus portion of sales under the PF Slice rate is already allocated its proper amount of 7(b)(3) rate protection costs. Doubleday *et al.*, WP-10-E-BPA-35, at 3. No further allocation of 7(b)(3) rate protection costs is necessary. *Id.* at 4.

Evaluation of Positions

The IOUs note that BPA's WP-07 Supplemental ROD concluded that the surplus portion of sales under the Slice rate is not afforded section 7(b)(2) rate protection. IOU Br., WP-10-B-JP1-01, at 46-47. The IOUs also note that, in this proceeding, BPA proposes to allocate the section 7(b)(3) trigger amount to three rate classes: 1) the PF Exchange rate; 2) the IP rate; and 3) the FPS contracts and surplus sales. *Id.* The FPS contracts and surplus sales to which BPA allocates section 7(b)(3) trigger amounts consist of secondary energy sales (including secondary energy sales to the Slice customers) and long-term contract sales (including Pre-Subscription sales, but not IRMP sales). *Id.* The IOUs note that BPA has two different methods for recovering allocated section 7(b)(3) trigger amounts:

a. For the section 7(b)(3) trigger amounts allocated to the PF Exchange rate and the IP rate, BPA develops supplemental rate charges and adds such supplemental rate charges to those rates. This method increases the revenue recovered from these rate schedules by the amount of the section 7(b)(3) supplemental rate charge.

b. For the section 7(b)(3) trigger amounts allocated to FPS contract sales, FPS secondary sales, and secondary energy sales under the Slice product, BPA reduces the secondary revenue credit, which credit is allocated to the unbifurcated PF rate. This method does not increase the revenue recovered from FPS contract sales, FPS secondary sales, and secondary energy sales under the Slice product.

Id.

The IOUs state that BPA does not recover, as a result of the section 7(b)(3) trigger amount allocation, increased revenues from FPS contract sales, FPS surplus sales, or the surplus portion of sales under the Slice rate. *Id.* at 48. The IOUs state that it appears that BPA's rationale for not doing so is based on the following: 1) FPS contract sales and FPS surplus sales are at prices set by either contract or the marketplace, 2) BPA has already forecast revenues and assumed revenues based on those contract prices and forecast market prices, and 3) BPA believes it could not, after making such forecast, recover additional costs from such contracts and surplus sales through imposition of supplemental rate charges. *Id.* The IOUs argue that BPA's own rationale does not apply to secondary energy sales under the Slice rate and does not preclude use of a 7(b)(3) Supplemental Rate Charge to increase revenues from those sales to recover section 7(b)(3) trigger amounts allocated to such sales. *Id.*

The IOUs have misconstrued BPA's rationale and practice concerning the allocation of 7(b)(3) rate protection amounts to power sales under the FPS rate schedule. During the allocation of the 7(b)(3) rate protection amount to all other power sold than PF Preference loads, the allocation factor for secondary and FPS contract loads includes the full forecast of secondary sales, both

Slice and non-Slice. RAM2010, tab 7b2 Allocation, cells F21 and G21, specifically the references to cells REV__SIM!I47 and J47.

Using FY 2010 as an example, the allocation factor is 2779.6 aMW, consisting of the 613 aMW allocation factor for FPS contracts plus the 2,166.6 aMW allocation factor for total secondary sales. This 2,166.6 aMW secondary sales allocation factor is derived by adding the 1,630 aMW of non-Slice secondary sales to the 477 aMW of Slice product secondary sales and adding a transmission loss factor to produce an energy allocation from the total sales amount. Therefore, the surplus portion of sales under the Slice rate is allocated a portion of the 7(b)(3) rate protection amount, and those sales are not afforded 7(b)(2) protection. Brodie *et al.*, WP-10-E-BPA-35, at 5.

After the 7(b)(3) allocation of the rate protection amount to all loads other than PF Preference loads is completed, no further allocation under 7(b)(3) is necessary or allowed. Contrary to the IOUs' position, because the total amount of the 7(b)(3) rate protection amount is already allocated, a further 7(b)(3) Supplemental Rate Charge to increase revenues from secondary energy sales under the Slice rate is precluded.

The IOUs state that BPA reduces the secondary revenue credit, which is allocated to the unbifurcated PF rate, by the section 7(b)(3) trigger amount allocated to FPS contract sales, FPS surplus sales, and secondary energy sales under the Slice product. IOU Br., WP-10-B-JP1-01, at 49. This reduction of the amount of the secondary revenue credit allocated to the unbifurcated PF rate increases that rate—which, in BPA's view, requires the section 7(b)(2) rate test to be rerun. *Id.* This causes the section 7(b)(3) trigger amount to increase, which, in turn, causes the supplemental rate charges allocated to the PF Exchange rate and the IP rate to increase. *Id.* BPA iterates this process until the section 7(b)(3) trigger amount does not change in the last iteration. *Id.* The IOUs claim that, as a result of BPA's iterative process, Slice customers likely pay less than 20 percent of section 7(b)(3) trigger amounts allocated to BPA Slice secondary energy sales. *Id.*

The IOUs state that the average 7(b)(3) Supplemental Rate Charge for FY 2010-2011 is proposed to be \$7.737 per MWh, and this is the section 7(b)(3) trigger amount that should be borne by projected secondary energy sales under the Slice rate. *Id.* The IOUs state that BPA projects that the surplus portion of sales under the Slice rate will be 477 aMW in FY 2010 and 486 aMW in FY 2011. *Id.* The IOUs conclude that applying the average 7(b)(3) Supplemental Rate Charge to the projected amount of secondary energy to be sold under the Slice rate results in a section 7(b)(3) trigger amount allocated to Slice secondary energy of \$32.6 million per year; therefore, the section 7(b)(3) supplemental rate charge recovered from the Slice rate as a result of secondary energy sales under the Slice rate should be \$32.6 million per year. *Id.* at 50.

As explained previously, and using FY 2010 as an example, the 477 aMW of Slice product secondary is allocated its proper amount of 7(b)(3) rate protection costs. The average amount of \$32.6 million calculated by the IOUs is included in the roughly \$184 million of 7(b)(3) rate protection costs allocated to the total secondary and FPS contract load. WPRDS Documentation, WP-10-E-BPA-05A, at 33, Table 2.5.9. Therefore, no further allocation of 7(b)(3) rate protection costs is necessary.

The IOUs state that under the BPA approach, the only impact on the Slice rate from allocation of the section 7(b)(3) trigger amount results from BPA including in the Slice rate formula the increased REP net benefits (which result from recognizing that the PF rate secondary revenue credit is reduced by the allocation of the section 7(b)(3) trigger amount to surplus power). IOU Br., WP-10-B-JP1-01, at 50. The IOUs note that, as BPA explained in the WP-07 Supplemental ROD, this is equivalent to assigning to the Slice rate the Slice percentage (22.63 percent) of the increased REP net benefits. *Id*. The IOUs state that this approach simply treats the Slice rate the same as the non-Slice PF Preference rate. *Id*.

BPA showed that its approach resulted in both Slice and non-Slice PF Preference customers bearing the same proportionate share of increased net REP benefits. *Id*. at 51. The IOUs claim that this showing in no way demonstrates the extent to which the secondary energy sold under the Slice rate bears any section 7(b)(3) trigger amounts. *Id*. The IOUs conclude that the comparability of treatment of the firm portion of the Slice product with the treatment of the non-Slice PF Preference product described by BPA fails to address the requirement that the secondary portion of power sold under the Slice rate must bear section 7(b)(3) trigger amounts. *Id*.

As discussed previously, the total amount of the 7(b)(3) rate protection is allocated to all other load, including the Slice portion of secondary. Any further allocation to the Slice portion of secondary and recovery of such allocation through a 7(b)(3) Supplemental Rate Charge, as the IOUs propose, would be double-counting and therefore inappropriate.

The IOUs propose that, for purposes of allocating section 7(b)(3) trigger amounts, BPA can and should treat the firm and secondary portions of the power sold under the Slice rate differently:

> (i) The firm power sold under the Slice rate should be treated comparably with the non-Slice PF Preference rate power. (This comparable treatment is what the WP-07 [Supplemental] ROD quotation at page 367 (conformed) demonstrates.)
>
> (ii) The secondary portion of the power sold under the Slice rate should be subject to a full *pro rata* share of the section 7(b)(3) trigger amount. (The comparability of treatment of the firm portion set forth above fails to address the requirement that the secondary portion of power sold under the Slice rate must bear section 7(b)(3) trigger amount.)

IOU Br., WP-10-B-JP1-01, at 51.

The IOUs conclude that the section 7(b)(3) trigger amount that should be recovered under the Slice rate as a result of the allocation of the section 7(b)(3) trigger amount to secondary energy sold under that rate is $32.6 million per year. *Id*. at 52. The IOUs also conclude that the only impact under the Initial Proposal on the Slice rate from allocation of the section 7(b)(3) trigger amount results from BPA including in the Slice revenue requirement the increased REP net benefits (which result from recognizing that the PF rate secondary revenue credit is reduced by the allocation of the section 7(b)(3) trigger amount to surplus power). *Id*. The IOUs expect that the impact would be similar to that which occurred in the WP-07 Supplemental rate proceeding—the allocation of the section 7(b)(3) trigger amount to surplus power as determined in the WP-07 Supplemental ROD (*see* quotation above) resulted in an increase in Slice costs of only about $6 million per year. *Id*. The IOUs state that it thus appears likely that, under BPA's proposal, the Slice rate bears only about $6 million of the section 7(b)(3) trigger amount, which is less than 20 percent of the $32.6 million of the section 7(b)(3) trigger amount that the Slice rate should appropriately bear as a result of secondary energy sales under the Slice rate. *Id*.

The IOUs conclude that BPA's approach results in the same impact, expressed in mills/kWh of requirements purchases, on Slice and non-Slice PF Preference rate customers, even though 1) the non-Slice PF preference rate customers purchase no BPA secondary under the PF Preference rate and 2) the Slice customers purchase substantial BPA secondary under the rate for the Slice product. *Id*. at 53. The IOUs state that the BPA approach likely results in Slice customers paying less than 20 percent of the section 7(b)(3) trigger amount allocated to BPA Slice surplus energy sales. *Id*.

The IOUs have miscalculated the rate effect of allocating the 7(b)(3) amount to BPA's surplus sales. As the IOUs observed above, the allocation of the 7(b)(3) amount has two different methodologies, depending upon whether the supplemental rate charge is applied to a class that will produce additional revenues or if it is applied to a load that produces a revenue credit. In the latter case, the revenue credit load absorbs an amount of 7(b)(3) costs equivalent to the supplemental rate charge. The rate effect of this lower revenue credit is felt by the rates that are allocated the credit and the subsequent rate design steps, such as the 7(b)(2) rate test. It is an over-simplification to assume, as the IOUs do, that the 7(b)(3) amount allocated to surplus sales will have the same rate effect as simply adding costs to a rate pool.

In the WP-07 Supplemental ROD, BPA proved that the only ratemaking effect of allocating the 7(b)(3) amount to all non-PF Preference loads, as the Northwest Power Act requires, is to modestly increase the forecast net REP benefits, and the Slice customers pay their percentage of the net REP benefits as a matter of course. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 363-364. BPA had performed a scenario analysis comparing 1) the WP-07 Supplemental Final Proposal ratemaking with 2) a scenario without the 7(b)(3) amount allocated to secondary sales. *Id*. (This analysis addressed NRU's request for a demonstration that there are no cost shifts between Slice and non-Slice customers as a result of the allocation of the 7(b)(3) amount to secondary sales.) *Id*. For FY 2009, the analysis produced a non-Slice PF rate of $26.46/MWh, an REP net benefits amount of $239.637 million, and a Slice cost of $517.65 million. *Id*. The WP-07 Supplemental Final Proposal produced a non-Slice PF rate of $26.90/MWh, an REP net benefits amount of $266.798 million, and a Slice cost of $523.524 million. *Id*.

To be equitable, the Slice cost should have recovered 22.63 percent of the increased net REP costs. *Id*. The difference in net REP costs was $266.798 million - $239.637 million = $27.162 million. *Id*. Slice should have recovered $27.162 million × 22.63% = $6.146 million. *Id*. The actual difference in Slice costs was $523.524 million - $517.65 million = $5.874 million. *Id*.
However, because the non-Slice PF rate increased by $0.44/MWh due to the allocation of 7(b)(3) amounts to secondary sales, the net cost of system augmentation paid by the Slice customers was

reduced by $0.272 million. *Id*. Therefore, the observed increase in the Slice cost of $5.874 million was net of a reduction in net system augmentation costs paid by Slice customers. *Id*. The observed increase in Slice costs of $5.874 million, when added to the $0.272 million in reduced net augmentation costs, yielded the $6.146 million that was the Slice share of the increased net REP costs. *Id*. This analysis showed that the Slice customers were paying 22.63 percent of the increased REP benefits, although there was a small secondary effect of slightly reducing their net system augmentation costs. *Id*.

The IOUs argue that the Slice rate for the sale of secondary energy is a BPA rate for the sale of power other than PF Preference rate power and, therefore, should be allocated the 7(b)(3) Supplemental Rate Charge at the same rate as other power that is not PF Preference rate power. IOU Br., WP-10-B-JP1-01, at 53. The IOUs state that under the BPA approach, there is no 7(b)(3) Supplemental Rate Charge applied to any portion of the power sold under the Slice rate. *Id*.

The IOUs state that BPA can and should develop a 7(b)(3) Supplemental Rate Charge to recover the section 7(b)(3) trigger amounts allocated to Slice secondary energy sales and add such 7(b)(3) Supplemental Rate Charges to the rates for those sales. *Id*. The IOUs state that BPA has not provided any reason for not using that method with respect to the Slice secondary energy. *Id*. Even assuming *arguendo* the validity of concerns regarding the allocation of section 7(b)(3) trigger amounts to rates established by contract or the marketplace, the IOUs state that any such concerns do not apply to the allocation of section 7(b)(3) trigger amounts to Slice surplus energy. *Id*. at 53-54. The IOUs assert that a section 7(b)(3) supplemental rate charge for sales of secondary energy under the Slice rate is permitted, for example, by Appendix A Section 4.B.3 of BPA's proposed General Rate Schedule Provisions. *Id*. at 54. Further, BPA sales of Slice surplus energy are not made at market-based rates. *Id*.

Accordingly, the IOUs state, BPA can and should develop and apply a 7(b)(3) Supplemental Rate Charge to the Slice rate to recover the full amount of the section 7(b)(3) trigger amount allocated to Slice surplus energy sales. *Id*. Under this approach, BPA would use the following two methods for recovering allocated section 7(b)(3) trigger amounts:

a. For the section 7(b)(3) trigger amounts allocated to the PF Exchange rate, the IP rate, and Slice secondary energy sales, BPA should develop supplemental rate charges and add such supplemental rate charges to those rates. This method increases the revenue recovered from these rate schedules by the amount of the section 7(b)(3) supplemental rate charge.

b. For the section 7(b)(3) trigger amounts allocated to FPS contract sales and FPS secondary sales, BPA should reduce the secondary revenue credit, which credit is allocated to the unbifurcated PF rate. This method does not increase the revenue recovered from FPS contract or FPS secondary sales.

Id. at 54.

The IOUs claim that under this approach, the secondary revenue credit would not be reduced by any section 7(b)(3) trigger amounts allocated to secondary energy sales under the Slice product. *Id*. Thus, the IOUs assert, any suggestion that this approach would result in Slice customers being double-charged for section 7(b)(3) trigger amounts or bearing more than their share of REP costs is misplaced. *Id*.

The Slice Group disagrees with the IOUs, stating that the IOUs urge BPA to impose on the PF Slice rate a direct allocation of an additional portion of the 7(b)(3) trigger amount. Slice Br., WP-10-B-JP4-01, at 6. The Slice Group suggests that the IOU proposal should be rejected for four primary reasons: 1) it would result in an inequitable and unlawful double allocation of 7(b)(3) trigger amounts to Slice customers; 2) it would require the unlawful imposition of a 7(b)(3) surcharge directly on the PF Slice rate, which is statutorily protected from such surcharges; 3) it would result in large disparities in the 7(b)(3) trigger amounts paid by individual Slice customers; and 4) it would result in a windfall increase in REP benefits. *Id*.

The Slice Group notes that, although it disagrees with BPA's basic decision to allocate part of the 7(b)(3) amount to surplus sales, the method chosen by BPA to make this allocation recognizes the differing nature of the PF rates and power supplies provided to Slice and non-Slice customers, and fairly apportions between Slice and non-Slice customers the section 7(b)(3) trigger amount it proposes to allocate to the PF rate. *Id*. BPA's method allocates to both Slice and non-Slice customers a full proportional share of the 7(b)(3) trigger amount based on their forecast requirements purchases from BPA under both the Slice and non-Slice PF rates. *Id*. at 6-7.

The Slice Customer Group states that the IOU proposal would upset this apportioning of 7(b)(3) trigger amount between Slice and non-Slice customers through imposition of a direct, dollar-for-dollar allocation of an additional portion of the 7(b)(3) trigger amount to the PF Slice rate. *Id*. at 7. The IOU proposal would result in the Slice customers being improperly charged two separate allocations of 7(b)(3) trigger amounts, the first through the increased net REP costs based on the BPA allocation, and a second, much larger, portion through a direct dollar-for-dollar allocation of the preliminary 7(b)(3) trigger costs to the PF Slice rate. *Id*. The Slice Group argues that such a double allocation of 7(b)(3) trigger amounts to Slice customers is both unlawful and inequitable, as it would result in the Slice customers bearing a disproportionately large portion of the 7(b)(3) trigger amount. *Id*.

The Slice Group argues that implementation of the IOU proposal would also require BPA to directly impose on the PF Slice rate a 7(b)(3) Supplemental Rate Charge, in contravention of the plain words of the statute. *Id*. The Slice product is comprised of the sale of firm power for the preference customers' requirements load, and the advance sale of surplus energy if and when available. *Id*. Slice customers do not receive a revenue credit based on forecast secondary revenues, as do all non-Slice PF rates. *Id*. Instead, Slice customers receive an in-kind delivery of surplus energy to the extent it is available. *Id*. The product is sold under a single PF Slice rate that does not differentiate between the firm and surplus components. *Id*. There is no separate sale of surplus energy to Slice customers, and no separate rate under which such surplus energy, if any, is sold. *Id*. at 7-8. It is all part and parcel of the service provided under the PF Slice rate. *Id*. at 8. As a consequence, implementation of the IOU proposal would require the imposition of a 7(b)(3) Supplemental Rate Charge on the rate that is protected from such surcharges by the very words of that statutory section. *Id*.

There is no separate rate for the surplus sale to Slice customers to which a 7(b)(3) Supplemental Rate Charge may be attached. The rate to Slice customers is the PF Slice rate, which is developed pursuant to section 7(b)(1) and is eligible for rate protection under section 7(b)(2). Under the PF Slice rate, Slice customers purchase power at a rate of general application for electric power sold to meet their general requirements. 16 U.S.C. § 839e(b)(1). This rate is subject to the consideration of the projected amounts to be charged for firm power for the general requirements of preference customers and may not exceed in total an amount equal to the power costs for general requirements of such customers. 16 U.S.C. § 839e(b)(2). The surplus power delivered with the sale of the firm power for the general requirements is an in-kind delivery in lieu of the section 7(b)(1) rate and revenue credit non-Slice customers receive for the value of the secondary energy. Therefore, the Slice Group is correct that the PF Slice rate is protected from the imposition of a 7(b)(3) Supplemental Rate Charge.

The Slice Group states that the IOU proposal also allocates 7(b)(3) trigger amounts to Slice customers based on the assumptions that average water will prevail, and that each Slice customer will receive its proportionate share of secondary energy based on such average water assumption. Slice Br., WP-10-B-JP4-01, at 8. The Slice Group states that these assumptions are unsound, because the amount of secondary energy actually available in any month may well fall short of the amount assumed by the IOUs, and variations in actual retail loads of Slice customers may result in what would otherwise be secondary energy being used to serve requirements load, and as a consequence being denominated as requirements power. *Id.*

The Slice Group is correct that assessing the PF Slice rate an additional amount calculated on the basis of average water prevailing during the FY 2010-2011 rate period may overstate or understate the actual amount of surplus power sold to Slice customers. For this reason, the 7(b)(3) Supplemental Rate Charge is developed as a unit rate, expressed in dollars per megawatthour. The proper application of the 7(b)(3) Supplemental Rate Charge should take into account the actual amount of power purchased under a rate subject to the 7(b)(3) Supplemental Rate Charge.

The PF Slice rate is not a rate that charges for the actual amount of power purchased. Instead, the PF Slice rate compensates BPA for a share of BPA's total costs, as expressed in the Slice revenue requirement, in exchange for an equivalent share of the output of the Federal generating system. The PF Slice rate does not change when surplus power is included in the amount delivered; therefore, it cannot be expressed in dollars per megawatthour. As such, there is no billing determinant (megawatthours) to which to attach a 7(b)(3) Supplemental Rate Charge.

The Slice Group states that the interaction of these factors from month to month will result in some Slice customers paying a 7(b)(3) Supplemental Rate Charge for secondary energy that is never made available to them from the Federal base system, or for surplus energy that is actually used for requirements load service due to variations in retail load levels. *Id.* The result is the creation of large disparities in the 7(b)(3) trigger amounts paid by, and the secondary energy actually provided to, individual Slice customers. *Id.*

The IOU proposal would result in an allocation of 7(b)(3) trigger amounts among Slice customers that would have little or no relation to the amount of secondary energy they actually receive over the course of the rate period, due to operational and retail load factors that are inherent in the Slice product. *Id*. at 8-9. It would also result in the 7(b)(3) Supplemental Rate Charge being assessed on power purchases under the PF Slice rate used to serve requirements load, a result that cannot be reconciled with the requirements of sections 7(b)(2) and 7(b)(3). *Id*. at 9.

The IOUs claim that the Slice Group erroneously argues that a 7(b)(3) Supplemental Rate Charge to the Slice rate to recover section 7(b)(3) trigger amounts allocated to Slice secondary energy sales would be inappropriate, by asserting that it:

> …could result in large disparities in the § 7(b)(3) surcharge amounts paid and the actual secondary energy provided to individual Slice product purchasers. It also has the potential for an inequitable distribution of the proposed § 7(b)(3) surcharge amounts among Slice purchasers due to operational and retail load factors that are inherent in the Slice product.

IOU Br., WP-10-B-JP1-01, at 55, *citing* Brawley *et al.*, WP-10-E-JP4-02, at 12.

The IOUs state that these arguments ignore the fact that any 7(b)(3) Supplemental Rate Charge to recover section 7(b)(3) trigger amounts is based on projected amounts to be charged as determined under section 7(b)(2). *Id*. The IOUs assert that BPA can and should develop a 7(b)(3) Supplemental Rate Charge to the Slice rate to recover section 7(b)(3) trigger amounts allocated to Slice secondary energy sales. *Id*.

The IOUs misstate the statute by transferring the reference to the "projected amounts to be charged" from section 7(b)(2) to section 7(b)(3). The "projected amounts to be charged" is used in the determination of whether such amounts exceed the power costs of the 7(b)(2) Case. The "projected amounts to be charged" language does not apply to the "supplemental rate charges for all other power sold." There is no instruction that supplemental rate charges be applied to "projected amounts," and assessing a supplemental rate charge on power that is simply projected, but turns out to be *not* sold, would be inequitable.

The Slice Group argues that the IOU proposal also should be rejected because it fails to take into account the impact of the IOUs' proposed direct allocation of 7(b)(3) trigger amounts to the PF Slice rate on the level of the PF cost pool used to develop the PF Exchange rate. Slice Br., WP-10-B-JP4-01, at 9. This results in an improper inflation of REP benefits available to the IOUs. *Id*. The Slice Group states that rather than using an iterative process, as BPA does, to account for the impact of 7(b)(3) allocation on the PF cost pool and the PF Exchange rate, the IOUs propose that the 7(b)(3) trigger amounts in the PF Exchange rates be decreased by the full amount of their proposed allocation to the PF Slice rate. *Id*. The IOUs fail to take into account the increase to the PF cost pool and the PF Exchange rate from their proposed direct allocation of the 7(b)(3) trigger amounts to the PF Slice rate. *Id*. The Slice Group claims the IOU proposal is an inequitable and unlawful allocation of 7(b)(3) trigger amounts to the PF Slice rate, which results in a windfall increase in the IOUs' REP benefits. *Id*.

Assuming, *arguendo*, it would be proper to allocate 7(b)(3) trigger amounts directly to the PF Slice rate, BPA would agree with the IOUs that the secondary revenue credit should not be decremented for such allocation. This would prevent the double collection of the 7(b)(3) trigger amounts that Slice customers claim would occur. However, BPA disagrees with the IOUs' proposal. As noted previously, the IOUs claim that recovering from the Slice customers a percentage equal to the Slice percentage of the increased net cost of the REP does not result in the Slice customers bearing their appropriate share of section 7(b)(3) trigger amounts. The IOUs claim that the surplus portion of sales under the Slice rate should be allocated its full *pro rata* share of section 7(b)(3) trigger amounts.

However, in the rate design portions of BPA's ratemaking, before the Slice Separation Step, the PF Preference load pool contains the Non-Slice PF load as well as the firm portion of the PF Slice product load. *Compare* the billing determinant used for the PF Preference rate, WPRDS Documentation, WP-10-E-BPA-05A, at 37, cell C52, with that used for the unbifurcated PF rate, *id*. at 38, cell C51. Doubleday *et al.*, WP-10-E-BPA-35, at 2.

Also, at this point in the ratemaking process, secondary sales include both the forecast secondary power marketed by BPA and the amount forecast to be sold with the Slice product. *Compare* the secondary revenues used during the 7(b)(3) allocation, WPRDS Documentation, WP-10-E-BPA-05A, at 27, cells B13 and C13, with the secondary revenues used in setting rates other than Slice, *id*. at 82, cells D16 and F16 (the difference being the Slice percentage, 22.263 percent, and displayed, *id*. at 35, cells D31 and E31). Doubleday *et al.*, WP-10-E-BPA-35, at 3.

During the allocation of the 7(b)(3) trigger amount to all loads other than PF Preference loads, the allocation factor for Secondary and FPS contract loads includes the full forecast of secondary power, both Slice and Non-Slice. *Id*. Using FY 2010 as an example, the Initial Proposal allocation factor is 2779.6 aMW, consisting of the 613 aMW allocation factor for FPS contracts plus the 2,166.6 aMW allocation factor for total secondary sales. *Id*. This 2,166.6 aMW secondary sales allocation factor is derived by adding the 1,630 aMW of non-Slice secondary sales to the 477 aMW of Slice product secondary sales and adding a transmission loss factor to produce an energy allocation from the total sales amount. *Id*. Therefore, the Slice product surplus sales are allocated a portion of the 7(b)(3) rate protection amount, and those sales are not afforded 7(b)(2) protection. *Id*.

As noted previously, the IOUs state that applying the average section 7(b)(3) Supplemental Rate Charge to the projected amount of secondary energy to be sold under the Slice rate results in a section 7(b)(3) trigger amount allocated to and collected from Slice secondary energy of $32.6 million per year; therefore, the IOUs claim, the 7(b)(3) Supplemental Rate Charge recovered from the Slice rate as a result of secondary sales under the Slice rate should be $32.6 million per year. *Id*. As explained previously, however, the 477 aMW of Slice product surplus sales is allocated its proper amount of 7(b)(3) rate protection costs. *Id*. The average amount of $32.6 million calculated by the IOUs is included in the roughly $184 million of 7(b)(3) rate protection costs allocated to the total secondary and FPS contract load. *Id*.
No further allocation of 7(b)(3) rate protection costs is necessary. *Id*. The result of this method is the same as would occur if the Slice product did not exist and BPA sold the secondary directly to market.

In their Brief on Exceptions, the IOUs argue that sales of secondary energy under the Slice rate constitute "other power sold" under section 7(b)(3) of the Northwest Power Act and should be subject to a 7(b)(3) Supplemental Rate Charge. IOU Br. Ex., WP-10-R-JP1-01, at 23. The IOUs state that BPA argues that a 7(b)(3) Supplemental Rate Charge may be imposed on surplus sales to Slice customers only if there is a separate rate for such surplus sales. *Id*., *citing* Draft ROD, WP-10-A-01, at 63. The IOUs argue, however, that section 7(b)(3) provides for "supplemental rate charges for all other power sold" (*i.e.*, other than PF Preference power). IOU Br. Ex., WP-10-R-JP1-01, at 23. The IOUs claim that section 7(b)(3) does not require or contemplate that there must be a separate rate for such sales for there to be a section 7(b)(3) Supplemental Rate Charge for such sales. *Id*. The IOUs reiterate that BPA's basic rationale for not applying a section 7(b)(3) Supplemental Rate Charge to FPS contract sales and FPS surplus sales—FPS contract sales and FPS surplus sales are at prices either set by contract or the marketplace—does not apply to secondary sales under the Slice rate. *Id*.

Contrary to the IOUs' assertion, section 7(b)(3) *does* contemplate that there must be a separate rate for such sales *by its very words*: "…shall be recovered through supplemental rate charges…." 16 U.S.C. § 839e(b)(3). The word "supplement" means "something added to complete a thing." Random House Dictionary, © Random House, Inc. 2009, accessed on July 10, 2009, through www.dictionary.com. In this case, to qualify as a *supplemental* rate charge, it has to be *added to* a rate charged for the power sold. Because there is no rate charged for the surplus power "sold," there can be no supplement to such non-existent rate.

The IOUs argue that sales of secondary energy under the Slice rate constitute "other power sold" under section 7(b)(3). IOU Br. Ex., WP-10-R-JP1-01, at 23. However, it is unclear whether the surplus power delivered to Slice purchasers is "power *sold* by the Administrator." The Slice purchasers are paying the Slice rate for firm requirements power. WP-02 Wholesale Power Rate ROD, WP-02-A-02, at 16-1. The Slice purchasers pay this rate *whether or not* any surplus power is generated and delivered. *See generally, id*.; Slice Br., WP-10-B-JP4-01, at 8. The Slice rate receives no revenue credits for BPA's sale of surplus power. In consideration for paying a rate that has no revenue credits, the Slice purchasers receive a share of any available surplus power in kind, *i.e.*, as power delivered. The Slice purchaser may be using such surplus power to resell into the wholesale power market *or* to serve requirements load. BPA does not know the disposition of such surplus power after it is delivered to Slice purchasers. It is inappropriate to levy a 7(b)(3) Supplemental Rate Charge on such power, especially if the power is being used to serve requirements load.

Furthermore, the IOUs' proposed solution creates an inequity. The IOUs propose that BPA should calculate the amount of revenue that would be received if a 7(b)(3) Supplemental Rate Charge were assessed to the amount of surplus power that is forecast in the rate case, and add such revenue to the Slice rate. This could put the Slice purchasers in the position of paying a 7(b)(3) Supplemental Rate Charge on power that they may not receive. For example, if BPA were to experience a critical water year during the rate period, no surplus power would be delivered to Slice purchasers. Yet, under the IOUs' proposal, Slice purchasers would still pay a 7(b)(3) Supplemental Rate Charge for an amount of power that was forecast in the rate case, even though that power was not actually purchased. Clearly, such a solution is inequitable.

Decision

BPA will not recover the section 7(b)(3) trigger amount allocated to the surplus portion of sales under the PF Slice rate through a 7(b)(3) Supplemental Rate Charge to the Slice rate.

Issue 3

Whether BPA's allocation of 7(b)(3) trigger amounts to secondary and surplus sales treats customer groups equitably in relation to one another.

Parties' Positions

PPC *et al.* argue that BPA's allocation of 7(b)(3) trigger amounts to secondary and surplus sales should treat Slice and non-Slice customers equitably in relation to one another. PPC *et al.* Br., WP-10-B-JP11-01, at 15-16.

NRU argues that in each WPRDS in each rate case in which BPA establishes and maintains Slice and non-Slice rates, BPA should make a demonstration that these two preference customer groups are treated equitably in relation to each other. NRU Br., WP-10-B-NR-01, at 8-9.

BPA Staff's Position

BPA's allocation of 7(b)(3) amounts to secondary and surplus sales is equitable to Slice and non-Slice customers. Brodie *et al.*, WP-10-E-BPA-35, at 4.

Evaluation of Positions

Despite the disagreement of PPC *et al.* with BPA's allocation of 7(b)(3) protection amounts to surplus and secondary sales, PPC *et al.* express an expectation that BPA's implementation of its decision will affect Slice and non-Slice customers to the same degree. PPC *et al.* Br., WP-10-B-JP11-01, at 15. PPC *et al.* state that it would be extremely disappointing for BPA to implement an allocation of protection amounts to surplus and secondary sales that resulted in customers being unduly penalized for their product choice, especially when BPA's proposed treatment of secondary revenues was wholly unanticipated at the time customers made their product choice, and the consequences of it continue to be unclear. *Id*. at 16.

BPA agrees. The allocation of 7(b)(3) protection amounts to surplus and secondary sales should not disproportionately affect preference customers based on their product choice.

NRU suggests that in each WPRDS in each rate case in which BPA establishes and maintains Slice and non-Slice rates, BPA should make a demonstration that these two preference customer groups are treated equitably in relation to each other. NRU Br., WP-10-B-NR-01, at 9. NRU states that BPA can expect that issues regarding potential cost shifts and the need for equitable treatment between these two customer classes will be recurring issues, and Slice and non-Slice customers should not have to seek these demonstrations in data requests. *Id*.

BPA agrees in this rate proceeding to produce a demonstration that non-Slice and Slice customers are treated equitably by the 7(b)(3) rate protection allocation to surplus power.

In its Brief on Exceptions, WPAG argues that secondary revenues should not bear a section 7(b)(3) Supplemental Rate Charge. WPAG Br. Ex., WP-10-R-WG-01, at 15-17. This issue was thoroughly addressed in BPA's WP-07 Supplemental ROD, which is incorporated by reference. Nevertheless, WPAG's arguments will be addressed in summary fashion below.

WPAG claims that in the Draft ROD BPA proposes to continue to allocate to the PF Preference rate a portion of the costs excluded from that rate by the section 7(b)(2) rate test. *Id*. at 15. BPA does not allocate any of the 7(b)(3) surcharge to the PF Preference rate. WPAG argues that the method used by BPA to make this allocation is complicated, and attempts to characterize what BPA has done as an improper 7(b)(3) surcharge. *Id*. WPAG claims that, first, a portion of the 7(b)(3) trigger amount is imposed on preference customers by a reduction in the secondary revenue credit used to calculate the unbifurcated PF revenue requirement. *Id*. This assertion is incorrect. The reduction of the secondary revenue credit due to an allocation of the 7(b)(3) trigger amount to secondary sales simply does not equate to an allocation of the trigger amount to the PF Preference rate. It is much more complex than this simple statement.

WPAG claims, second, that the net REP benefits paid to the IOUs, and funded by preference customers, are thereby increased. *Id*. However, the fact that a decrease in the secondary revenue credit increases REP benefits is simply a result of the proper implementation of the Act's rate directives. Logically, when the secondary revenue credit decreases, the unbifurcated PF rate (the PF rate before the rate test) increases. But this is only in the Program Case. When the rate test is conducted, because 7(b)(2) Case rate bears no such allocation of the section 7(b)(3) trigger amount, the difference between the constant 7(b)(2) Case rate and increased the Program Case rate is higher. The secondary revenue credit in the 7(b)(2) Case remains the same as it is before the Program Case secondary revenue credit is reduced by such allocation. Thus, again logically, a higher rate test trigger results in lower REP benefits for exchanging preference and IOU customers. The increase in REP benefits resulting from the allocation of the 7(b)(3) trigger amount to secondary is therefore mitigated by the increase in the rate protection amount.

WPAG asserts, third, that BPA's preference customers pay a higher PF rate than they would absent this allocation. *Id*. Once again, however, if the secondary revenue credit to the PF Preference rate is decreased, the PF Preference rate will increase, and vice versa. This reflects the proper effect of a change in the secondary revenue credit on the PF Preference rate.

WPAG argues, fourth, that all preference customers end up paying a share of the costs excluded from the PF rate by the 7(b)(2) rate test. *Id*. This argument is also incorrect. Contrary to WPAG's argument, preference customers do not end up paying any costs excluded by the rate test but, instead, pay the appropriate costs that reflect the statutory requirement that some of the 7(b)(3) surcharge must be allocated to BPA's surplus power sales.

WPAG argues that BPA's allocation of the 7(b)(3) surcharge to BPA's surplus power sales is inconsistent with sections 7(b)(2) and 7(b)(3) of the Act and creates a conflict between these two statutory provisions where no such conflict should exist. WPAG Br. Ex., WP-10-R-WG-01, at 15-17. Contrary to WPAG's argument, however, BPA's interpretation does not create a conflict between sections 7(b)(2) and 7(b)(3), but instead resolves a conflict. BPA's interpretation, which provides for recovery of part of the trigger amount from BPA's surplus sales through a supplemental rate charge in the FPS rate schedule, harmonizes the need to recover the trigger amount through supplemental rate charges with the statutory direction to recover the trigger amount from all of the Administrator's power sales, and with the rate protection afforded preference customers by section 7(b)(2) of the Act, through retaining the unreduced secondary revenue credit in the 7(b)(2) Case. This argument was thoroughly addressed in BPA's WP-07 Supplemental ROD, which is incorporated by reference.

WPAG argues that BPA's method of recovering some of the trigger amount from BPA's surplus power sales does not recover any additional revenues to replace those that cannot be collected under the PF rate due to the 7(b)(2) rate ceiling test. WPAG Br. Ex., WP-10-R-WG-01, at 15-17. This argument also was thoroughly addressed in BPA's WP-07 Supplemental ROD, which is incorporated by reference. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 335-368.

In summary, BPA correctly concluded that, as expressly required by section 7(b)(3) of the Northwest Power Act, some of the trigger amount must be recovered from *all* of BPA's non-PF Preference power sales, which include surplus sales. BPA has proposed a means to implement this rate directive in a manner consistent with section 7(b)(2). The public agencies' arguments are directly and unequivocally inconsistent with the section 7(b)(3) requirement to recover the trigger amount from *all* non-PF Preference power sales. Such an untenable argument cannot stand.

Decision

BPA's allocation of 7(b)(3) amounts to secondary and surplus sales treats customer groups equitably in relation to one another. BPA will provide a demonstration of such equitable treatment in the Final WPRDS.

8.5 Allocation of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to Surplus Sales

Issue 1

Whether BPA should include surplus sales in the allocation of the Section 7(b)(2) Industrial Adjustment 7(c)(2) Delta.

Parties' Positions

The IOUs argue that BPA should allocate a *pro rata* share of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales. IOU Br., WP-10-B-JP1-01, at 57-67; IOU Br. Ex., WP-10-R-JP1-01, at 3-8. The IOUs further argue that any 7(b)(2) Industrial Adjustment 7(c)(2) Delta is an "amount not charged to public body, cooperative, and Federal agency customers by reason of [Northwest Power Act section 7(b)(2)]" and, therefore, the allocation of both the 7(b)(2) Industrial Adjustment 7(c)(2) Delta and the section 7(b)(3) trigger amounts is governed by section 7(b)(3), and BPA must allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales. IOU Br., WP-10-B-JP1-01, at 59; *see also* IOU Br. Ex., WP-10-R-JP1-01, at 6-7.

BPA Staff's Position

Staff 's testimony disagreed with the IOUs' argument that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta should be borne by all BPA power rates, including the PF Preference rate, the PF Exchange rate, the IP rate, the New Resources rate, the FPS rate, and the Slice rate. Brodie *et al.*, WP-10-E-BPA-35, at 7-8. The IOUs did not pursue this argument in brief; rather, the IOUs modified the argument such that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta should be allocated to surplus sales made under the FPS rate schedule. Staff is not persuaded by the IOUs' argument that the allocation of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is governed by section 7(b)(3) of the Northwest Power Act. *Id.*

Evaluation of Positions

In their Initial Brief, the IOUs describe their understanding of BPA's ratemaking pertaining to the 7(b)(2) Industrial Adjustment 7(c)(2) Delta:

> After the 7(c)(2) Adjustment, BPA runs the section 7(b)(2) rate test. If the section 7(b)(2) rate test triggers, a portion of any section 7(b)(3) trigger amount is allocated to the IP Rate, and BPA performs the "7(b)(2) Industrial Adjustment."
>
> In the 7(b)(2) Industrial Adjustment, BPA recalculates the IP rate revenue requirement using the PF Preference rate (plus margin minus VOR credit plus section 7(b)(3) trigger allocation) that results from the removal of the section 7(b)(3) trigger amount from the PF Preference rate. (*Id.*) This recalculated IP rate revenue requirement is used to recalculate a "7(b)(2) Industrial Adjustment 7(c)(2) Delta," which the Initial Proposal describes as follows:
>
> > The second adjustment is the 7(b)(2) Industrial Adjustment. The amount of this adjustment is the value of a recalculated 7(c)(2) delta at the lower PF Preference rate that resulted from the allocation of the 7(b)(2) rate protection to the PF Preference rate. The same adjustments described in the 7(c)(2) Adjustment, section 3.3.4, are performed again with the lower PF Preference rate.
>
> The 7(b)(2) Industrial Adjustment reduces the IP rate revenue requirement by the 7(b)(2) Industrial Adjustment 7(c)(2) Delta.
>
> The 7(b)(2) Industrial Adjustment 7(c)(2) Delta is about $53 million over the two-year rate period or about $26.5 million per year. BPA allocates the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to the PF Exchange rate and the NR rate. The result of the section 7(b)(2) rate test and follow-on rate design steps is that the PF Exchange rate bears
>
> > (i) its full share of the section 7(b)(3) trigger amount as determined by BPA and
> >
> > (ii) the entire 7(b)(2) Industrial Adjustment 7(c)(2) Delta.

IOU Br., WP-10-B-JP1-01, at 57-58.

BPA generally agrees with the IOUs' description of BPA's ratemaking regarding the 7(b)(2) Industrial Adjustment 7(c)(2) Delta. WPRDS, WP-10-E-BPA-05, sections 3.3.4, 3.3.5, and 3.3.6. The IOUs argue that under BPA's application of the section 7(b)(2) rate test, the PF Exchange rate bears its share of the section 7(b)(3) trigger amount allocation determined by BPA and the entire 7(b)(2) Industrial Adjustment 7(c)(2) Delta, which is roughly equal to the section 7(b)(3) trigger amount that BPA allocated to the IP rate. *Id.* at 58. The IOUs argue that therefore, in effect, the PF Exchange rate bears not only its share of the section 7(b)(3) trigger amount allocation determined by BPA, but also essentially all of the IP rate's share of the section 7(b)(3) trigger amount allocation determined by BPA. *Id.*

The IOUs' description appears to connect 1) the 7(b)(3) allocation of a portion of the PF Preference protection amount to the IP rate to 2) the need for the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation. In fact, however, the 7(b)(3) amount allocated to the IP rate stays with the IP rate even after the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation is completed. It is the lower PF Preference rate due to the application of the 7(b)(2) rate protection that necessitates the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation. This result can be seen in the Initial Proposal in the WPRDS Documentation, WP-10-E-BPA-05A, at 34, Table 2.5.10. The IP rate's shares of the 7(b)(2) adjustment before and after the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation are shown on lines 2 and 7, respectively. The values on lines 2 and 7 are nearly identical: $27.4 million and $27.2 million for FY 2010 and FY 2011, respectively. The $26.5 million per year 7(b)(2) Industrial Adjustment 7(c)(2) Delta is caused by the lower IP revenues at the now-lower PF Preference rate.

The IOUs argue that, in the Draft ROD, BPA misstated their position by stating in the Staff position that the IOUs requested that the section 7(b)(2) Industrial Adjustment 7(c)(2) Delta be allocated to the PF Preference and other rates. IOU Br. Ex., WP-10-R-JP1-01, at 3. Instead, the IOUs claim that what they support in their Initial Brief is for the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to be allocated to surplus sales. *Id.*

The overview of Staff's position above reflects the position of the parties as of the end of the hearing phase of this case. In testimony, the IOUs' witnesses argued that BPA should allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to the PF Preference and other rates. *See* La Bolle *et al.*, WP-10-E-JP1-01, at 46. Staff objected to this proposal in their testimony, which is why Staff reiterated their view above in the description of Staff's position. *See* Brodie *et al.*, WP-10-E-BPA-35, at 7-8. BPA is encouraged by the fact that the IOUs have now abandoned this line of argument. BPA adjusted its description of Staff's position to make clear that the IOUs are no longer advocating that BPA allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to PF Preference and other rates, but only to surplus sales.

The IOUs note that, in its rebuttal testimony, Staff argued that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is not allocated to the PF Preference rate by reason of section 7(b)(2): "Any further allocation of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta amount to the PF Preference rate would violate 7(b)(2) rate test protection." IOU Br., WP-10-B-JP1-01, at 59, *citing* Brodie *et al.*, WP-10-E-BPA-35, at 5-6. The IOUs argue that, assuming *arguendo* that BPA cannot allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to the PF Preference rate by reason of section 7(b)(2), then BPA must, consistent with section 7(b)(3) of the Northwest Power Act, allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to BPA sales of all other power, including for surplus sales. IOU Br., WP-10-B-JP1-01, at 59. The IOUs cite section 7(b)(3) of the Northwest Power Act as expressly requiring such allocation:

> …any amounts not charged to public body, cooperative, and Federal agency customers by reason of [Northwest Power Act section 7(b)(2)] shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers.

Id., *citing* 16 U.S.C. § 839e(b)(3).

Accordingly, the IOUs argue, any 7(b)(2) Industrial Adjustment 7(c)(2) Delta is an amount "not charged to public body, cooperative, and Federal agency customers by reason of [Northwest Power Act section 7(b)(2)]." *Id.* The IOUs argue, therefore, the allocation of both 7(b)(2) Industrial Adjustment 7(c)(2) and section 7(b)(3) trigger amounts is governed by section 7(b)(3), and BPA must allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales. *Id.*

The IOUs have misconstrued sections 7(b)(2), 7(b)(3), and 7(c)(2) of the Northwest Power Act in a manner that would shift costs away from the PF Exchange rate. In the WP-10 Initial Proposal, the 7(b)(2) rate test triggered by $8.07 per MWh, resulting in approximately $514.6 million per year in PF Preference rate protection. WPRDS Documentation, WP-10-E-BPA-05A, at 33, Table 2.5.9. The entire amount of the rate protection is then allocated to all other load as directed by section 7(b)(3) of the Act. *Id.* The IP rate revenue requirement is allocated approximately $27.3 million per year through section 7(b)(3). *Id.* After the allocation of the total amount of 7(b)(2) PF Preference rate protection to all other non-PF Preference load through the 7(b)(3) process, there are no further rate protection amounts, and no further 7(b)(3) allocations are necessary.

The IOUs have noticed that the $27.3 million per year in 7(b)(3) allocation to the IP rate is similar to the $26.5 million per year 7(c)(2) allocation to the PF Exchange rate. WPRDS Documentation, WP-10-E-BPA-05A, at 33, Table 2.5.9. The IOUs argue that these two very different ratemaking steps, which are in effect currently producing similar numbers, are one and the same and should both be controlled by section 7(b)(3). IOU Br., WP-10-B-JP1-01, at 3. This is incorrect. Section 7(b)(3) controls the allocation of PF Preference rate protection, and section 7(c)(2) controls the relationship between the levels of the IP rate and BPA's applicable wholesale rate. These two very different calculations can be seen in Tables 2.5.9 and 2.5.10 cited above.

The IOUs contend in their Brief on Exceptions that the above description of their position is erroneous. IOU Br. Ex., WP-10-R-JP1-01, at 3-4. The IOUs assert that it is not their position that these two ratemaking steps are "one and the same" and that they are therefore both controlled by section 7(b)(3). *Id.* at 4. The IOUs claim that the Draft ROD responds to this erroneous premise by demonstrating that these two ratemaking steps are different. *Id.* However, the IOUs' argue the fact that these two ratemaking steps are indeed different in no way establishes that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is not subject to section 7(b)(3). *Id.*

The discussion above responds to the IOUs' assertion that by allocating the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to the PF Exchange rate, the PF Exchange rate is not only being allocated its share of the section 7(b)(3) trigger amounts, but also the section 7(b)(3) trigger amounts assessed to the IP rate. As noted above, the IOUs have attempted to support this statement by pointing out that the amount of section 7(b)(3) surcharge dollars allocated to the IP rate is similar to the amount being allocated to the PF Exchange rate through the 7(b)(2) Industrial Adjustment 7(c)(2) Delta. In their Brief on Exceptions, the IOUs quibble with BPA's use of the phrase "one and the same" in describing their argument. While a more artful term could have been chosen, BPA has not misunderstood the essence of the IOUs' argument, which asserts that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is allocating to the PF Exchange rate the same dollars that BPA allocated to the IP rate through the section 7(b)(3) amount. As noted in the IOUs' Brief on Exceptions:

> … the *effect* on the PF Exchange rate of bearing not only its share of the section 7(b)(3) trigger amount allocation determined by BPA but also the entire 7(b)(2) Industrial Adjustment 7(c)(2) Delta is essentially the same as bearing not only the PF Exchange rate's share of the section 7(b)(3) trigger amount allocation determined by BPA but also essentially all of the *<u>IP rate's share of the section 7(b)(3) trigger amount</u>* allocation determined by BPA.

IOU Br. Ex., WP-10-R-JP1-01, at 4 (first emphasis in original, underlined emphasis added).

As discussed above, the IOUs' assertion is unfounded. Section 7(b)(3) dollars are *not* reallocated from the IP rate to the PF Exchange rate when BPA performs the 7(b)(2) Industrial Adjustment 7(c)(2) Delta. The 7(b)(2) Industrial Adjustment 7(c)(2) Delta is an independent adjustment that calculates a different set of dollars when BPA is re-linking the IP rate to the PF rate as required by section 7(c)(2) of the Act. The fact that, in this rate case, this adjustment allocates an amount that is "roughly equal" to the amount allocated under section 7(b)(3) is simply a coincidence and does not support the IOUs' assertion that the PF Exchange rate is being allocated additional section 7(b)(3) dollars. Indeed, in many instances these numbers are vastly different. For example, in the WP-02 rate case, the IP rate was allocated approximately $248 million of the section 7(b)(3) trigger amount. *See* 2002 Final WPRDS, Documentation Volume 1, WP-02-FS-05A, at 73. However, when performing the 7(b)(2) Industrial Adjustment 7(c)(2) Delta adjustment in that case, only $148 million was allocated to the PF Exchange rate. *Id.* at 75. Thus, the IOUs' assertion that BPA is allocating (or "effectively" allocating) the IP rate's share of the section 7(b)(3) trigger amounts to the PF Exchange rate through the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is simply incorrect.

The IOUs state that in cross-examination, Staff recognized that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is caused by the section 7(b)(2) rate test and the allocation of the section 7(b)(3) trigger amount that results from the section 7(b)(2) rate test:

> Q. Is the 7(b)(2) industrial adjustment 7(c)(2) delta part of the 7(b)(3) trigger amount, in your view?
>
> A. (Mr. Doubleday) It is not part of the trigger amount, but it is caused by the 7(b)(2) rate test and the resultant allocation of costs through 7(b)(3), because it's at that point that the PF preference rate -- the unbifurcated PF rate is

> bifurcated into the lower PF preference and the higher PF exchange, and that lower PF preference actually drives the 7(b)(2) industrial adjustment 7(c)(2) delta. They're not one and the same, but they are related.

IOU Br., WP-10-B-JP1-01, at 60, *citing* Cross Ex. Tr. 68.

The Staff witness clearly states, however, that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is *not* part of the 7(b)(3) trigger amount. The witness goes on to describe how it is the lower PF Preference rate that necessitates the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation and not the 7(b)(3) allocation of rate protection to the IP rate. As discussed above, the rate protection amount allocated to the IP rate through section 7(b)(3) remains with the IP rate after the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation and is not reallocated to the PF Exchange rate as the IOUs suggest. BPA's ratemaking has many steps and, as the witness observes when discussing the 7(b)(3) allocation step and the following 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation step, they are not in effect one and the same but are related in that the ending cost allocation from the 7(b)(3) step is the beginning cost allocation for the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation.

The IOUs argue that, assuming *arguendo* that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is not part of the section 7(b)(3) trigger amount and that its allocation is not governed by section 7(b)(3), BPA should nevertheless make an allocation of 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales. IOU Br., WP-10-B-JP1-01, at 60. The IOUs claim that the absence of an express statutory requirement to allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta amount to, for example, the PF Exchange rate and surplus sales does not and cannot justify the arbitrary decision to allocate essentially all of such amount to the PF Exchange rate and none to surplus sales. *Id*.

The IOUs assert that allocating essentially all of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to the PF Exchange rate, thus allocating none of it to surplus sales, is inequitable and arbitrary. *Id*. The IOUs claim that allocation of the *pro rata* share of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales would not violate section 7(b)(2) of the Northwest Power Act and would not disturb what BPA considers to be the appropriate relationship between the IP and PF Preference rates. *Id*.

Contrary to the IOUs' argument, allocating essentially all of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to the PF Exchange rate, thus allocating none of it to surplus sales, is not inequitable and is not arbitrary. It would make no sense to allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales. The firm surplus sales are made at negotiated rates, and any further allocation of costs to these sales would result in a revenue deficiency. This revenue deficiency would require adjustment of other rates. At this point in BPA's ratemaking, the PF Preference rate cannot be increased to recover the deficiency, because it would violate the section 7(b)(2) rate protection. The IP rate cannot be increased to recover the deficiency, because it would violate the section 7(c)(2) rate linkage. The only remaining rates are the PF Exchange and NR rates, exactly those rates to which the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is allocated in BPA's current methodology.

Section 7(a)(1) of the Northwest Power Act requires BPA to develop power rates that recover BPA's power-related costs. Therefore, unresolved revenue deficiencies are not allowed under BPA ratemaking. In addition, sections 7(b)(2) and 7(c)(2) of the Act direct Staff to develop the PF Preference and IP rates in accordance with the terms of those respective sections of the Act. There are no sections of the Northwest Power Act that direct BPA to allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales.

As stated in section 8.2 above, the statutory direction for the allocation of costs to sales at FPS rates allows BPA to determine that other costs are allocable to FPS sales. The 7(b)(2) Industrial Adjustment 7(c)(2) Delta is not a resource cost allocable pursuant to section 7(f); therefore, the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is allocated pursuant to section 7(g). With section 7(g), the direction is that the Administrator shall equitably allocate certain costs to power rates in accordance with generally accepted ratemaking principles and the provisions of the Northwest Power Act. As discussed herein, the provisions of section 7 do not discuss the allocation of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta, but such allocation to the PF Preference rate and to the IP rate would not be in accordance with the provisions of section 7. Therefore, the remaining direction is that the Administrator shall equitably allocate certain costs to power rates, in accordance with generally accepted ratemaking principles. This language grants the Administrator discretion in the allocation of the costs of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta. Allocating the 7(b)(2) Industrial Adjustment 7(c)(2) Delta on the basis of firm power sold at adjustable rates is a reasonable and equitable basis.

The IOUs argue that BPA should allocate a *pro rata* share of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to sales under the surplus rates using an iterative process similar to the process that BPA uses to allocate section 7(b)(3) trigger amounts. IOU Br., WP-10-B-JP1-01, at 61. The IOUs state that Staff recognizes that it is possible to allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales:

> Q. So what I'm trying to understand is – and I guess I would ask you to assume, for your purposes, hypothetically, that if Bonneville were to conclude that it was appropriate to allocate 7(b)(2) industrial adjustment 7(c)(2) delta to secondary sales, would it be possible if Bonneville were doing that to use an iteration approach to determine how much 7(c)(2) industrial adjustment 7(c)(2) delta should be allocated to the secondary or surplus sales of BPA without creating a revenue deficiency, just as Bonneville does on the 7(b)(3) trigger amount?
>
> A. (Mr. Doubleday) Well, I think hypothetically that if you were to have a second iteration after the first that we have discussed earlier, what would happen is that you would allocate 7(c)(2) industrial adjustment dollars to PF Exchange rate, NR and, in your hypothetical, secondary sales and surplus contract sales. Now, at this point in time in the rate making, you've already established what secondary revenue credit goes into the unbifurcated PF rate and, therefore, went into the PF preference rate after the 7(b)(2) rate test. So I don't see that you could allocate really anything to secondary which would leave you with the surplus contract sales. With the surplus contract sales, we already forecast what the revenues would be for the year. So this iteration that

you're positing here would allocate costs to these contracts. It would establish because they would be allocating more costs than the sales could support, that would be a revenue deficiency, and the iterative process would just be a way of reallocating from getting rid of that deficiency and putting those very same dollars back on to the only two rates that we feel can be adjusted at this point in rate making, which is the PF exchange and NR. Which is why, in answer to your -- to the data requests that are now in the record, we've said that the way we've done it and an iterative process would get you to the same spot in our thinking.

* * * *

Q. Would it be possible to rerun the 7(b)(2) test after you allocate -- if you were to allocate 7(b)(2) industrial adjustment 7(b)(2) delta to secondary, would it be possible to rerun the 7(b)(2) test after that allocation?

A. (Mr. Doubleday) Well, in rate modeling there's a multitude of things that are possible, in your hypothetical. But staff believes that while the iterative process for 7(b)(3) is required by our understanding of the Regional Act, there is no such language covering the 7(b)(2) industrial adjustment 7(c)(2) delta, and so there was no reason for staff to contemplate running the 7(b)(2) test through a second set of iterations.

Id. at 61-62, *citing* Cross Ex. Tr. at 66, 72.

The Staff witness was commenting on an IOU-posed hypothetical, which assumed that BPA allocated a portion of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales. The witness states, however, that such a circumstance would create a revenue deficiency. Section 7(a)(1) of the Northwest Power Act requires BPA to develop power rates that recover BPA's power-related costs. Therefore, unresolved revenue deficiencies are not allowed under BPA ratemaking. As stated above, the revenue deficiency would require adjustment of other rates. The PF Preference rate cannot be increased to recover the deficiency, because it would violate the section 7(b)(2) rate protection. The IP rate cannot be increased to recover the deficiency, because it would violate the section 7(c)(2) rate linkage. The only remaining rates capable of receiving the 7(b)(2) Industrial Adjustment 7(c)(2) Delta costs not recoverable through surplus sales are the PF Exchange and NR rates.

The IOUs argue that Staff's rebuttal testimony erroneously asserts that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta may be allocated to only the PF Exchange rate and the NR rate. IOU Br., WP-10-B-JP1-01, at 62. The IOUs state that notwithstanding Staff's recognition that it would be possible to allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to rates other than the PF Exchange rate and the NR rate, the Staff rebuttal testimony erroneously asserts that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta may be allocated to only the PF Exchange rate and the NR rate. *Id*.

The IOUs state that Staff provides the following arguments in support of this erroneous assertion: 1) section 7(c)(2) of the Act does not require that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta be allocated to BPA's sales of surplus power; 2) the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is not a supplemental rate charge and is not required to be allocated to all firm power sold by the Administrator; and 3) the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is a rate adjustment used to adjust the level of the IP, PF, and NR rates so they have what BPA considers to be a "proper relationship to one another":

> Based on our understanding of the Northwest Power Act, section 7(c)(2) of the Act does not require that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta be allocated to BPA's sales of surplus power (in this case, load served under the FPS rate). In contrast, section 7(b)(3) of the Act requires that the 7(b)(3) supplemental rate charge be applied to all firm load served by the Administrator. The 7(b)(2) Industrial Adjustment 7(c)(2) Delta is not a supplemental rate charge and is not required to be allocated to all firm power sold by the Administrator. The Delta, and its subsequent allocation, is a rate adjustment used to adjust the level of the IP, PF, and NR rates so they have the proper relationship to one another. As such, the adjustments are made to rates whose levels can be adjusted at this point in BPA's ratemaking: the PF Exchange and NR rates.

Id., *citing* Brodie *et al.*, WP-10-E-BPA-35, at 7.

The IOUs claim that these arguments in the Staff rebuttal testimony are erroneous for a number of reasons. IOU Br., WP-10-B-JP1-01, at 62.

The IOUs claim that Staff's assertion that "section 7(c)(2) of the Act does not require that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta be allocated to BPA's sales of surplus power (in this case, load served under the FPS rate)" misses the point. *Id.* at 63. Similarly, the IOUs claim, Staff's assertion that the "7(b)(2) Industrial Adjustment 7(c)(2) Delta is not a supplemental rate charge and is not required to be allocated to all [other] power sold by the Administrator" also misses the point. *Id.* The IOUs claim that section 7(b)(3) of the Northwest Power Act requires that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta be allocated to BPA's sales of surplus power (in this case, load served under the FPS rate). *Id.* The IOUs state, however, that even if there is no express statutory requirement to allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta amount to, for example, the PF Exchange rate and surplus sales, that does not and cannot justify the arbitrary decision not to allocate any such amount to surplus sales (*e.g.*, through an iterative process, such as the one described below). *Id.*

This argument is not persuasive. The IOUs have misconstrued sections 7(b)(2), 7(b)(3), and 7(c)(2) of the Act. After the total amount of 7(b)(2) PF Preference rate protection is allocated to all other non-PF Preference load through the 7(b)(3) process, there are no further rate protection amounts and no further 7(b)(3) allocations necessary. BPA's ratemaking has many steps. The 7(b)(3) allocation step and the following 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation step are not in effect one and the same, but they are related in that the ending cost allocation from the 7(b)(3) step is the beginning cost allocation for the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation. The IOUs suggest that these two very different ratemaking steps, 7(b)(3) and 7(c)(2), are in effect one and the same and should both be controlled by section 7(b)(3). Section 7(b)(3), however, controls the allocation of PF Preference rate protection, and section 7(c)(2) controls the relationship between the levels of the IP rate and BPA's applicable wholesale rate. WPRDS, WP-10-E-BPA-05, sections 3.3.4, 3.3.5, and 3.3.6.

Second, the IOUs argue that there is no reason to believe that allocation of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales will prevent what BPA considers to be the "proper relationship" among the IP, PF, and NR rates, provided that BPA allocates the 7(b)(2) Industrial Adjustment 7(c)(2) Delta using an iterative process. IOU Br., WP-10-B-JP1-01, at 64. The 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation step is conducted after the 7(b)(2) rate test and after the 7(b)(3) allocation of PF Preference rate protection to all other loads. It is the 7(b)(3) allocation of rate protection amounts away from the PF Preference rate pool that necessitates the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation step. The PF Preference revenue requirement is set after BPA conducts the 7(b)(2) rate test.

After that rate test protection amount is set and removed from the PF Preference revenue requirement, the PF Preference rate revenue requirement is set and does not change. With a stable PF Preference revenue requirement, the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation step stabilizes the IP rate revenue requirement. As stated above, allocating a 7(b)(2) Industrial Adjustment 7(c)(2) Delta amount to surplus sales would create a revenue deficiency that would require the adjustment of other rates. The PF Preference rate cannot be increased in violation of the section 7(b)(2) rate protection. The IP rate cannot be increased in violation of the section 7(c)(2) rate linkage. The only remaining rates are the PF Exchange and NR rates, which are the rates to which the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is allocated in BPA's current methodology.

The IOUs claim there is no reason to assume that only the PF Exchange and NR rates can be adjusted and that BPA must adhere to an unnecessary and seemingly arbitrary sequencing of its ratemaking steps. *Id*. The IOUs state that BPA's rationale for allocating the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to only the PF Exchange rate and the NR rate seems to be that BPA has chosen a particular sequencing of its rate steps:

> Q. What criteria does BPA use in determining where to allocate 7(b)(2) industrial adjustment 7(c)(2) delta?
>
> A. Well, as I've said earlier, the only -- we feel at this point in the rate making, the only two adjustable rates that can -- the only rates that can be adjusted at this point are the PF exchange rate and the NR rate.

Id., *citing* Cross Ex. Tr. at 68. The IOUs claim that this logic is circular, because BPA cannot choose its ratemaking sequence rather than the iterative approach for allocating the 7(b)(2) Industrial Adjustment 7(c)(2) Delta and then argue that BPA cannot allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales because of its choice. IOU Br., WP-10-B-JP1-01, at 64.

To the contrary, however, BPA's ratemaking sequence is logical and necessary. The 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation step can be conducted only after the 7(b)(2) rate test and after the 7(b)(3) allocation of PF Preference rate protection to all other loads. It is the 7(b)(3) allocation of rate protection amounts away from the PF Preference rate pool that lowers the PF Preference rate and necessitates the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation step. If the 7(b)(2) rate test does not indicate any rate protection for the PF Preference rate, there is no resulting allocation pursuant to section 7(b)(3), and there is no 7(b)(2)

Industrial Adjustment 7(c)(2) Delta. The ordering of these steps is not just BPA's choice; these steps cannot be performed in any other order.

As stated above, the iterative process favored by the IOUs would result in either a revenue deficiency, because costs that would be ultimately unrecoverable would be allocated to the surplus rate pool, or would yield the same result that BPA attains using its current methodology. There is a difference between the 7(b)(3) rate protection amount allocation and the 7(b)(2) Industrial Adjustment 7(c)(2) Delta allocation. The iterative process BPA uses to allocate 7(b)(3) amounts to surplus occurs in BPA's ratemaking in concert with the 7(b)(2) rate test and determines the secondary revenue credit applied to the unbifurcated PF rate. It is only after that iteration process that the unbifurcated PF rate can be used in the 7(b)(2) rate test.

The 7(b)(2) Industrial Adjustment 7(c)(2) Delta ratemaking step occurs after the 7(b)(2) rate test and after the 7(b)(3) rate protection allocations. As discussed above, at this point in the ratemaking the only rates that can bear the 7(b)(2) Industrial Adjustment 7(c)(2) Delta are the PF Exchange and NR rates. This is true whether BPA's method is used or if an iterative process were used that allocated the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to the PF Exchange, NR, and surplus rates, and then spread the surplus deficiency back to the PF Exchange and NR rates.

Finally, the IOUs argue that if allocation of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is not governed by section 7(b)(3), and if adding the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to the IP rate violates the IP rate directive, then—by the same logic—adding the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to the PF Exchange rate violates the PF Exchange rate directives (under which the PF Exchange rate is to equal resource costs pursuant to section 7(b)(1) of the Northwest Power Act plus an allocation of the section 7(b)(3) trigger amount). *Id*. at 64-65.

To the contrary, however, section 7(c)(2) of the Act directs BPA to set the IP rate so that it has a specific relationship to BPA's applicable wholesale rate. 16 U.S.C. § 839e(c)(2). Section 7(c)(2) essentially makes the IP rate a formula rate. BPA calculates the IP rate revenue requirement using the PF Preference rate plus the margin, minus the VOR credit, plus the section 7(b)(3) trigger allocation. Contrary to the IOUs' contention, the PF Exchange rate is not a formula rate under any rate directive.

The IOUs argue that allocation of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales would not result in a revenue deficiency. *Id*. at 65. The IOUs note that BPA's rebuttal testimony asserts that the allocation of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales would result in a revenue deficiency:

> Also, it would not make sense to allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales. The firm surplus sales are made at negotiated rates, and any further allocation of costs to these sales would result in a revenue deficiency. This revenue deficiency would require adjustment of other rates. The PF Preference rate cannot be increased to recover such deficiency, because it would violate the section 7(b)(2) rate protection. The IP rate cannot be increased to recover such deficiency because it would violate the section 7(c)(2) rate linkage. The only remaining rates are the PF Exchange and NR rates, exactly those rate to which the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is allocated in

our current methodology. The same logic holds for secondary sales. The result of the IOU proposal would be identical to our current method.

Id., citing Brodie *et al.*, WP-10-E-BPA-35, at 8.

The IOUs claim that BPA thus argues that any further allocation of costs to firm surplus sales (including secondary energy sales) would result in a revenue deficiency (or require a reduction in the secondary revenue credit) that would require adjustment of other rates, such as the PF Preference rate, and that such adjustment would be contrary to the section 7(b)(2) rate test. IOU Br., WP-10-B-JP1-01, at 65. The IOUs argue that BPA determined in the WP-07 Supplemental ROD, however, that the secondary revenue credit could be reduced by allocating the section 7(b)(3) trigger amount to the secondary revenue credit, rerunning the section 7(b)(2) rate test to determine a revised section 7(b)(3) trigger amount that reflected the reduced secondary revenue credit, and then repeating this iterative process until the section 7(b)(3) trigger amount was unchanged when the section 7(b)(2) rate test was rerun. *Id.* at 65-66. Similarly, the IOUs state that BPA can and should reduce the secondary revenue credit by allocating section 7(b)(3) trigger amounts to 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales (which reduces the secondary revenue credit), rerunning the section 7(b)(2) rate test to determine a revised section 7(b)(3) trigger amount that reflected the reduced secondary revenue credit, and then repeating this iterative process until the section 7(b)(3) trigger amount is unchanged when the section 7(b)(2) rate test was rerun. *Id.* at 66.

While it is mechanically possible to allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales, it is questionable whether such an actions would be appropriate. The IOUs continue to argue that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation is analogous to the 7(b)(3) allocation of the 7(b)(2)-derived PF Preference rate protection amount and, therefore, deserving of the iterative treatment. As discussed earlier, however, the two ratemaking steps are quite different. The 7(b)(2) Industrial Adjustment 7(c)(2) Delta adjustment must occur after the 7(b)(3) allocation, by definition. Therefore, it is not just a matter of the sequencing of the rate steps and deserving of iterative treatment. Because the two ratemaking steps occur in sequence, one after the other, clearly they are not in effect the same. In addition, they are not controlled by the same section of the Act. The IOUs go so far as to say that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation is controlled by section 7(b)(3) of the Act. Clearly, it is not. The 7(b)(2) Industrial Adjustment 7(c)(2) Delta adjustment is designed to bring the IP rate into the proper relationship with the lower PF Preference rate after the 7(b)(2) rate test is completed and after the 7(b)(3) supplemental rate charges have been established. It is section 7(c)(2) of the Act that controls the rate adjustments used to bring the IP rate into conformance with the PF rate, and section 7(c)(2) does not require a specific allocation. Lacking a specific allocation, section 7(g) controls, such that BPA's allocation need only be equitable and in accordance with generally accepted ratemaking principles. BPA's method meets both standards.

The IOUs, in their Brief on Exceptions, disagree with this argument, noting that merely because the 7(b)(2) Industrial Adjustment 7(c)(2) Delta may have been "designed to bring the IP rate into the proper relationship with the lower PF Preference rate" does not and cannot alter the fact that at least the portion of such 7(b)(2) Industrial Adjustment 7(c)(2) Delta not allocated to the PF Preference rate must be allocated pursuant to section 7(b)(3). IOU Br. Ex., WP-10-R-JP1-01, at 7. This argument fails, however, because the IOUs are viewing the 7(b)(2) Industrial

Adjustment 7(c)(2) Delta as an "amount" that is governed by section 7(b)(3). As discussed more fully below, this reading of the statutory language is misplaced.

The IOUs state: "BPA can and should reduce the secondary revenue credit by allocating section 7(b)(3) trigger amounts to 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales (which reduces the secondary revenue credit), rerunning the section 7(b)(2) rate test to determine a revised section 7(b)(3) trigger amount that reflected the reduced secondary revenue credit, and then repeating this iterative process until the section 7(b)(3) trigger amount was unchanged when the section 7(b)(2) rate test was rerun." *Id*. This is another example of comingling the 7(b)(3) rate step and the 7(b)(2) Industrial Adjustment 7(c)(2) Delta rate step. The IOUs confuse section 7(c)(2) with section 7(b)(3). Section 7(c)(2) has no language that supports the IOUs' position.

Section 7(c)(2) of the Northwest Power Act does not require that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta be allocated to BPA's sales of surplus power (in this case, load served under the FPS rate). In contrast, section 7(b)(3) of the Act requires that the 7(b)(3) supplemental rate charge be applied to all other power sold by the Administrator. The 7(b)(2) Industrial Adjustment 7(c)(2) Delta is not a supplemental rate charge and is not required to be allocated to "all other power sold by the Administrator to all customers." 16 U.S.C. § 839e(b)(3). The Delta, and its subsequent allocation, is a rate adjustment used to adjust the level of the IP, PF, and NR rates so they have the proper relationship to one another. As such, the adjustments are made to rates whose levels can be adjusted at this point in BPA's ratemaking: the PF Exchange and NR rates. Also, it would make no sense to allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales. The firm surplus sales are made at negotiated rates and, as explained previously, any further allocation of costs to these sales would result in a revenue deficiency that could not be allocated to the PF Preference or IP rates.

The iterative process described by the IOUs treats the allocation of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta essentially the same as the allocation of the section 7(b)(3) trigger amount, in that they would both reduce the secondary revenue credit applied to the unbifurcated PF rate. Leaving aside the fact that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is not the same as the section 7(b)(3) trigger amount, and the two different rate steps are controlled by two different sections of the Act, the required sequencing of the two different steps renders the IOU proposal ineffective. The 7(b)(2) rate test and the determination of the 7(b)(3) supplemental rate charges must, by definition, be performed before the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation. BPA's current ratemaking iterates the 7(b)(2) rate test and the determination of the 7(b)(3) supplemental rate charges until the secondary credit to the unbifurcated PF rate is stable, and then proceeds to the remaining rate design steps, including the bifurcation of the PF rate into the PF Exchange rate and PF Preference rate and the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation.

The IOUs propose that some portion of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta be allocated to surplus sales, thereby lowering the secondary revenue credit, and then reiterating the 7(b)(2) rate test and the determination of the 7(b)(3) supplemental rate charges until the secondary credit to the unbifurcated PF rate is stable, then performing the 7(b)(2) Industrial

Adjustment 7(c)(2) Delta calculation again and allocating a portion of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to secondary, thereby lowering the credit, and so on and so on.

This protracted iteration and reiteration is certainly possible from a computer modeling perspective, but it would render very little difference in the PF Exchange rate. Lowering the secondary revenue credit to the unbifurcated PF rate would raise the PF Preference rate. Raising the PF Preference rate, in the absence of explicit instruction such as that contained in section 7(b)(3), is not allowed under the "shall not exceed" test in section 7(b)(2). Therefore, the IOUs' iterative approach would not work. BPA is not objecting to the iteration solely on the basis that it is an iteration. For example, an iteration would be appropriate if an NLSL were being served at the NR rate, thus affecting the section 7(c)(1) applicable wholesale rate. In such a case, an allocation of the Delta to the NR rate would change the IP rate, resulting in either an iteration or an algebraic solution to such an iteration.

The IOUs argue that an iterative approach, in effect, treats the allocation of 7(b)(2) Industrial Adjustment 7(c)(2) Delta essentially the same as the allocation of section 7(b)(3) trigger amount. IOU Br., WP-10-B-JP1-01, at 66. The IOUs claim that failure to allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales on the grounds that such allocation would cause a revenue deficiency is tantamount to erroneously 1) assuming that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is always equal to zero; 2) calculating an overstated secondary revenue credit based on this erroneous assumption; and 3) asserting that it is then somehow too late to correct this erroneous assumption and that as a result the 7(b)(2) Industrial Adjustment 7(c)(2) Delta must be allocated only to the PF Exchange rate and the NR rate. *Id.* The IOUs argue that no such assumption is necessary or appropriate under an iterative approach. *Id.*

As stated above, however, the IOUs argue that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta calculation is analogous to the 7(b)(3) allocation of the 7(b)(2)-derived PF Preference rate protection amount. As discussed earlier, the two ratemaking steps are quite different. The 7(b)(2) Industrial Adjustment 7(c)(2) Delta adjustment occurs after the 7(b)(3) allocation, by definition. Although the two ratemaking steps occur in sequence, one after the other, they are not in effect the same, and they are not controlled by the same section of the Act. Further, the language of section 7(b)(3) refutes the IOUs' position. Section 7(b)(3) states that any amounts not charged to preference customers by reason of section 7(b)(2) shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers. 16 U.S.C. § 839e(b)(3).

In their Brief on Exceptions, the IOUs reiterate their arguments that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta must be allocated to surplus sales pursuant to the provisions of section 7(b)(3). IOU Br. Ex., WP-10-R-JP1-01, at 5-6. The IOUs' argument on this point can be summed up in the following faulty syllogism: 1) section 7(b)(3) says that "any amounts not charged" to the preference customers because of section 7(b)(2) must be allocated to all other power sold under the Act, such as surplus sales; 2) the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is not allocated to the PF Preference rate because of section 7(b)(2); 3) therefore, the 7(b)(2) Industrial Adjustment 7(c)(2) Delta must be allocated to all other power sold under the Act, such as surplus sales. *Id.*

This syllogism, however, fails because it is founded on several incorrect premises. First, the language of the Northwest Power Act does not support the IOUs' assertion that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is an amount that is "not charged to preference customers" as stated in section 7(b)(3). Section 7(b)(3) provides:

> Any amounts not charged to public body, cooperative, and Federal agency customers by reason of [Northwest Power Act section 7(b)(2)] shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers.

16 U.S.C. § 839e(b)(3). It is a fundamental canon of statutory construction that words or phrases in a statute be read in context and with a view to their place in the overall statutory scheme. *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 133, 120 S.Ct. 1291, 146 L.Ed.2d 121 (2000) (*quoting Davis v. Michigan Dep't of Treasury*, 489 U.S. 803, 809, 109 S.Ct. 1500, 103 L.Ed.2d 891 (1989)). In the instant case, the "amounts" referred to in section 7(b)(3) are those amounts (if any) that are removed from the rates charged to preference customers as a result of the 7(b)(2) rate test. That amount is a specific sum of dollars that is allocated away from the PF preference rate at the conclusion of the 7(b)(2) rate test and allocated to all other power sold by BPA. Viewed in this context, the most natural reading of the statutory language is that the "amount" referred to in section 7(b)(3) is the trigger "amount" BPA removes from the PF rate as a consequence of the 7(b)(2) rate test. The 7(b)(2) Industrial Adjustment 7(c)(2) Delta is not affected by this language because it is not an "amount" that is allocated away from the preference customers as a result of the 7(b)(2) rate test. Rather, it is an adjustment that arises by reason of re-linking the IP rate to the revised PF rate pursuant to section 7(c)(2), which occurs *after* the section 7(b)(3) trigger amounts have been finally determined and fully allocated. *See* WPRDS, WP-10-E-BPA-05, sections 3.3.4 and 3.3.6.

To avoid this logical construction of the Act, the IOUs argue that the "amounts" referred to in section 7(b)(3) are not only the amounts determined in section 7(b)(2) but also any other undefined "amounts" that are not allocated to the preference customers' rates as a consequence of the rate test. This expansive reading of the text is unsupportable. For section 7(b)(3) to apply to the 7(b)(2) Industrial Adjustment 7(c)(2) Delta, section 7(b)(3) would have to read that "any amounts not charged to industrial customers by reason of section 7(c)(1) shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers." The fact that section 7(b)(3) does not so provide, and there is no other such direction, is compelling. "[W]here Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion." *United States v. Youssef*, 547 F.3d 1090, 1094-95 (9th Cir. 2008) *quoting Russello v. United States*, 464 U.S. 16, 23 (1983). In the instant case, Congress did not direct BPA to allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to "all other power sold" by BPA. In addition, the language in section 7(b)(3) contains no references to the adjustments associated with section 7(c)(2). Faced with these omissions in the statutory language, BPA does not believe it would be reasonable to interpret the word "amounts" out of context and expand its meaning to include other adjustments, such as the 7(b)(2) Industrial Adjustment 7(c)(2) Delta adjustment, as suggested by the IOUs.

Furthermore, the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is a rate adjustment and not a supplemental rate charge. As such, the adjustments are made to rates whose levels can be adjusted: the PF Exchange and NR rates. Technically, the IOUs are incorrect that the 7(c)(2) Delta is allocated solely to the PF Exchange rate; it is also allocated to the NR rate. From a practical perspective, however, there is no NR rate service forecast in this rate case, and all of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta necessarily must be allocated to the PF Exchange rate.

The IOUs argue that, moreover, the allocation of a *pro rata* share of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales would not allocate more dollars to that load than the load could recover through sales. IOU Br., WP-10-B-JP1-01, at 66. In its Response to Data Request No. PS-BPA-14, BPA stated as follows:

> [S]imple logic dictates that if BPA were to allocate more dollars to a load than the load could recover though sales, there would be a revenue deficiency. That is, by definition, the revenue from that load would be deficient in recovering the costs allocated to that load.

Id. at 66-67.

The IOUs claim there would still be a substantial secondary revenue credit even if the secondary energy sales revenues after "7b3 Allocation" were reduced or offset by an allocation of 7(b)(2) Industrial Adjustment 7(c)(2) Delta. *Id*. at 67. The IOUs state that BPA projects secondary energy sales revenues after the "7(b)(3) Allocation" that would exceed $1.3 billion during the FY 2010-2011 rate period. The total 7(b)(2) Industrial Adjustment 7(c)(2) Delta for this same period is slightly more than $53 million.

The IOUs further argue that given the fact that BPA's projected surplus sales revenues will dwarf the total 7(b)(2) Industrial Adjustment 7(c)(2) Delta allocated to surplus for the FY 2010-2011 rate period, there is no basis for concluding that an allocation of 7(b)(2) Industrial Adjustment 7(c)(2) Delta to BPA surplus sales would create a revenue deficiency *(i.e.*, "the revenue from that load" would not be "deficient in recovering the costs allocated to that load"). *Id*. Further, the IOUs state that there would be no overall revenue deficiency if BPA were to use the iterative approach discussed above to allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to BPA surplus sales. *Id*.

The IOU proposal is an unwarranted complication that has no basis in BPA's rate directives or ratemaking history. The IOUs are correct that the 7(b)(2) Industrial Adjustment 7(c)(2) Delta amount is less than the total secondary revenue credit, but that fact is beside the point. The mere fact that an ineffective and unsupportable ratemaking treatment is technically possible is no reason to adopt that treatment. An allocation of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus, which would reduce the secondary revenue credit to the PF Preference rate, would still run afoul of the language in section 7(b)(2), which states that "the amounts to be charged" preference customers (which includes the revenue credit) "*may not exceed*" the power costs for preference customer requirements determined pursuant to the remaining provisions of section 7(b)(2). A reduction in the secondary revenue credit to the "amounts to be charged" would cause such amounts to "exceed" the power costs for preference customer requirements determined pursuant to the remaining provisions of section 7(b)(2). Without clear direction requiring an allocation of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to surplus sales, as is the case with the rate protection amount in section 7(b)(3), such allocation is not appropriate.

In their Brief on Exceptions, the IOUs argue that the iterative process is not an "unwarranted complication," but a requirement of section 7(b)(3). IOU Br. Ex., WP-10-R-JP1-01, at 8. This is incorrect. As noted above, section 7(b)(3) addresses "amounts" determined as a consequence of the section 7(b)(2) rate test, not "adjustments" that result from BPA's implementation of section 7(c)(2), which occur *after* the section 7(b)(2) rate test is complete. Thus, the IOUs are mistaken in asserting that section 7(b)(3) directs the allocation of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta.

Decision

The 7(b)(2) Industrial Adjustment 7(c)(2) Delta ratemaking step is not controlled by section 7(b)(3) of the Northwest Power Act. BPA will continue to allocate the 7(b)(2) Industrial Adjustment 7(c)(2) Delta to the PF Exchange and NR rate pools.

9.0 RESIDENTIAL EXCHANGE PROGRAM: AVERAGE SYSTEM COST

9.1 Introduction

The Residential Exchange Program (REP) was created by section 5(c) of the Northwest Power Act to provide residential and small farm customers of Pacific Northwest (regional) utilities a form of access to low-cost Federal power. Under the REP, BPA purchases power from each participating utility at that utility's Average System Cost (ASC). BPA establishes a utility's ASC through a formal ASC Review Process. Once a utility's ASC is established, BPA offers, in exchange, to sell an equivalent amount of electric power to the utility at BPA's Priority Firm Power (PF) Exchange rate. The exchange actually transfers no power to or from BPA because the "exchange" is simply an accounting transaction: "In practice, only dollars are exchanged, not electric power." *CP Nat'l Corp. v. BPA*, 928 F.2d 905, 907 (9th Cir. 1991) (*as amended*), *quoting Public Util. Comm'r of Oregon v. Bonneville Power Admin.*, 583 F.Supp. 752, 754 (D. C. Or. 1984). The amount of power purchased and sold between BPA and the utility is equal to the utility's qualifying residential and small farm load. The Northwest Power Act requires that all of the net benefits of the REP be passed through directly to the residential and small farm customers of the participating utilities. 16 U.S.C. § 839c(c)(3).

9.2 Average System Cost

The ASC is the unit cost of a utility's allowable generation and transmission system as determined by the Administrator through the ASC Review Process, an extensive review of the utility's cost and load data. ASC (expressed in $/MWh) equals a utility's ASC Contract System Cost divided by its ASC Contract System Load.

ASC Contract System Cost and ASC Contract System Load are determined by following the prescribed functionalization rules and requirements identified in the 2008 Average System Cost Methodology (2008 ASCM), an administrative rule developed by BPA in consultation with its customers and other stakeholders. *See* 16 U.S.C. § 839c(c)(7); *see also* 18 C.F.R.§ 301.1-301.9. The Commission granted interim approval of the 2008 ASCM on October 10, 2008. *See Sales of Elec. Power to the Bonneville Power Administration, Revisions to Average System Cost Methodology*, 73 Fed. Reg. 60,105 (Oct. 10, 2008). The Review Processes for individual utilities' ASC filings occur in a separate administrative forum that is not part of the WP-10 rate proceeding. *Id*.

Once the ASC Review Processes are complete, BPA publishes an ASC Report for each utility, which establishes each utility's final ASC(s). The final ASCs are used to calculate the utilities' REP benefits for the term of the ASC Exchange Period, which coincides with BPA's FY 2010-2011 rate period. Utilities' ASCs are used as an input to estimate REP costs for purposes of setting rates.

Background information, publications, procedures and review schedules, and BPA's published reports are available at http://www.bpa.gov/corporate/finance/ascm/.

9.3 Average System Cost Forecast for FY 2010-2011

Utilities' ASCs for FY 2010-2011 were determined in BPA's FY 2010-2011 ASC Review Processes and not in this rate proceeding. Russell *et al.*, WP-10-E-BPA-18, at 5. Issues related to the FY 2010-2011 ASCs are not within the scope of the WP-10 rate proceeding. *Id.*; *see also* 74 Fed. Reg. 6,609, at 6,615 (Feb. 10, 2009). To forecast utilities' ASCs for the FY 2010-2011 rate period, Staff used the "as filed" ASCs submitted by the utilities in October of 2008 for the FY 2010-2011 ASC Review Process. Russell *et al.*, WP-10-E-BPA-18, at 6. These "as-filed" ASCs were temporary placeholders while BPA completed the ASC Review Processes. *Id.*

On July 21, 2009, BPA issued the Final FY 2010-2011 ASC Reports for eight utilities that submitted ASC filings for consideration in BPA's ASC Review Process. *See* http://www.bpa.gov/corporate/finance/ascm/fy10-asc-final-reports.cfm. The Final FY 2010-2011 ASC Reports have been incorporated into the administrative record of this proceeding. Consistent with Staff's proposal, BPA has updated the placeholder ASCs used in the Initial Proposal with the ASCs determined in BPA's Final FY 2010-2011 ASC Reports.

There were no issues raised by parties with respect to BPA's use of the "as-filed" ASCs for FY 2010-2011 or with BPA's decision to update the "as-filed" ASCs with the final ASCs determined in the Final FY 2010-2011 ASC Reports.

9.4 Average System Costs for FY 2012-2015

To perform the section 7(b)(2) rate test, BPA must have forecast ASCs for FY 2012-2015 for utilities participating in the REP. Russell *et al.*, WP-10-E-BPA-18, at 9. To develop these forecasts, Staff uses a similar methodology as is used to determine the ASCs for FY 2010-2011. *Id.* at 10. Staff uses the costs and loads in the rate period ASCs as the starting point. *Id.* The rate period ASCs include the costs of all new resources forecast to come on-line through the end of the rate period. *Id.* Then, each line item in the FY 2010-2011 Contract System Cost forecast is linked to an escalator in a computer model, referred to as the ASC Forecast Model. *Id.* To calculate the ASCs for FY 2012-2015, the ASC Forecast Model escalates the rate period ASC values forward through FY 2015. *Id.*

The ASC Forecast Model is designed to apply different escalation factors to the various cost and revenue categories used to calculate Contract System Cost. *Id.* In general, the ASC Forecast Model uses the same escalators described in the 2008 ASCM. *Id.* The escalation rates are displayed in the Section 7(b)(2) Rate Test Study Documentation, WP-10-BPA-FS-06A, Appendix E, Table 5. The results of the ASC forecast for each year of the rate test period are shown in the Section 7(b)(2) Rate Test Study Documentation, WP-10-BPA-FS-06A, Appendix F, Tables A-H.

The FY 2012-2015 ASC forecast assumes that all load growth is met with market purchases at utility-specific market rates. The utility-specific market rates are calculated using the individual utilities' price spreads contained in each utility's ASC filing. The Contract System Loads used

in the FY 2012-2015 ASC forecast are shown in the Section 7(b)(2) Rate Test Study Documentation, WP-10-BPA-FS-06A, Appendix E, Table 2.
Forecasts of ASCs for FY 2012-2015 are calculated for all utilities that filed ASCs with BPA in October 2008. The filing utilities are Avista, Idaho Power Company, NorthWestern Energy, PacifiCorp, Portland General Electric, Puget Sound Energy, Franklin County PUD, and Snohomish County PUD. *See* Section 7(b)(2) Rate Test Study Documentation, WP-10-BPA-FS-06A, Appendix E, Table 3, for a summary of the FY 2012-2015 ASC forecasts for these utilities.

Similar to the FY 2010-2011 ASCs, Staff stated that it would update the FY 2012-2015 forecast of ASCs to reflect any changes that resulted from the final ASC Review Process determinations for the FY 2010-2011 rate period ASCs. Russell *et al.*, WP-10-E-BPA-18, at 13. In addition, Staff stated that it would update the ASC forecast to reflect the Final Proposal natural gas price forecast, electric energy market price forecast, and PF rates. *Id*.

As noted above, the Final FY 2010-2011 ASC Reports were issued by BPA on July 21, 2009. BPA has updated the forecast ASCs for FY 2012-2015 to reflect any changes made in the final ASC Reports.

There were no issues raised by the parties with respect to BPA's forecast of utilities' ASCs for FY 2012-2015.

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10.0 SECTION 7(b)(2) RATE TEST

10.1 Introduction

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

To understand the context of the development of BPA's rates and the implementation of the section 7(b)(2) rate test, it is helpful to review the genesis of the Northwest Power Act. BPA was established by the Bonneville Project Act of 1937 (Project Act), 16 U.S.C. § 832, *et seq*. The Project Act authorized BPA to market the low-cost hydropower generated by Federal dams in the PNW. Although section 4(a) of the Project Act requires BPA to "give preference and priority to public bodies and cooperatives" when selling power, 16 U.S.C. § 832c(a), BPA had sufficient power for many years to serve the needs of all customers in the region. These customers include public bodies and cooperatives, known as "preference customers" because of their statutory first right to Federal power under the preference clause noted above. *Id*. BPA's customers also included IOUs and DSIs. Starting in 1948, the increasing demand for power caused BPA to require that contracts with the DSIs must include provisions to allow the interruption of service when necessary to meet the needs of BPA's preference customers. H.R. Rep. No. 96-976, Part 2, at 28 (1980). In the 1970s, forecasts showed that preference customers soon would require all of BPA's power. *Id*. Therefore, in 1973, BPA gave notice that new contracts for firm power to IOUs would not be offered, and that as DSI contracts expired between 1981 and 1991, the contracts were not likely to be renewed. *Id*. at 29. In 1976, BPA advised preference customers that BPA would not be able to satisfy preference customer load growth after 1983, and would have to determine how to allocate power among preference customers. *Id*. at 30.

The high cost of alternative sources of power caused BPA's non-preference customers to attempt to regain access to cheap Federal power. *Id*. at 30. Many areas served by IOUs moved to establish public entities designed to qualify as preference customers and be eligible for administrative allocations of power. Because the Project Act provided no clear way of allocating power among preference customers, and because the stakes involved in buying cheap Federal power had become very high, the competition for administrative allocations threatened to produce contentious litigation. *Id*. The uncertainty inherent in the situation greatly complicated the efforts by all BPA customers to plan for their future power needs. *Id*. at 31. To avoid the prospect of unproductive and endless litigation regarding access to the Federal power marketed by BPA, Congress enacted the Northwest Power Act in 1980. 16 U.S.C. § 839, *et seq*.

Numerous, complex tradeoffs were necessary in order to resolve the competing claims for BPA's low-cost hydropower in the late 1970s, and to solve the electric power planning uncertainties facing the PNW at that time. The provisions of the Northwest Power Act reflect the give and take of those tradeoffs. The Northwest Power Act established new directives regarding regional electric power planning, establishing the Pacific Northwest Electric Power and Conservation Planning Council (Northwest Power and Conservation Council). 16 U.S.C. § 839b. The Act granted the Administrator new authority to acquire resources to serve BPA's customers. 16 U.S.C. § 839d. The Act also established new directives regarding BPA's power sales, 16 U.S.C. § 839c, and new directives for the establishment of BPA's rates for power and transmission services, 16 U.S.C. § 839e.

The Northwest Power Act reaffirmed the right of BPA's preference customers to first call on Federal power before such power could be offered to BPA's IOU or DSI customers. 16 U.S.C. § 839g(c). The Act also established the right of BPA's preference customers and investor-owned utility customers to receive service from BPA to meet their net requirements. 16 U.S.C. § 839c(b)(1). Similarly, the Act required BPA to establish initial long-term power sales contracts with its DSI customers, and provided the Administrator the discretionary authority to serve the DSIs after their initial contracts expired. 16 U.S.C. § 839c(d).

Although the Northwest Power Act established the right of BPA's IOU customers to receive service from BPA to meet their net requirements, the rate applicable to such service would be set at the cost of new resources rather than the embedded cost of the hydrosystem. Therefore, the Act also established the REP. 16 U.S.C. § 839c(c). As noted above, when BPA had insufficient Federal power to meet the needs of IOUs in the 1970s, such utilities developed their own resources, which generally were more costly than Federal hydropower. The REP provides Pacific Northwest utilities (both preference customers and IOUs) a form of access to low-cost Federal power. Under the program, a Pacific Northwest utility may sell power to BPA at a rate based on the utility's average system cost of its resources. BPA is required to purchase that power and sell, in exchange, an equivalent amount of power to the utility at BPA's PF rate. This is the same rate that applies to BPA's sales of power to its preference customers, although the Act provides that the PF rate for the REP may be higher than the PF rate for preference customers due to the section 7(b)(2) rate test. 16 U.S.C. § 839e(b)(3). When a utility's ASC is higher than BPA's PF rate, the difference between the two rates is multiplied by the utility's residential load to determine an amount of money that is paid to the utility as REP benefits. These benefits must be passed through directly to the utility's residential and small farm consumers through lower retail rates. The utilities themselves receive no benefits from the REP. The cost of BPA providing these benefits to exchanging utilities' residential consumers is borne primarily by BPA's consumer-owned utility and DSI customers, subject to the rate test in section 7(b)(2) of the Northwest Power Act.

The Northwest Power Act also established new ratemaking directives. Section 7(a)(1) of the Act reiterated BPA's most critical rate directive: BPA's rates must be established to recover BPA's costs. Section 7(a)(1) provides:

> 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 cost associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this chapter and other provisions of law. Such rates shall be established in accordance with sections 9 and 10 of the Federal Columbia River Transmission System Act [16 U.S.C. 838g and 838h], section 5 of the Flood Control Act of 1944 [16 U.S.C. 825s], and the provisions of this chapter.

16 U.S.C. § 839e(a)(1).

Section 7(a)(2) of the Act governs review and approval of BPA's rates, conditioning such approval on the ability of BPA's rates to recover BPA's total costs:

> Rates established under this section shall become effective only, except in the case of interim rules as provided in subsection (i)(6) of this section, upon confirmation and approval by the Federal Energy Regulatory Commission upon a finding by the Commission, that such rates—
>
> (A) 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,
>
> (B) are based upon the Administrator's total system costs, and
>
> (C) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system.

16 U.S.C. § 839e(a)(2).

The Act also establishes specific rate directives for the power sold to BPA's customer classes, including preference, IOU, and DSI customers. Section 7(b)(1) of the Northwest Power Act prescribes the manner in which BPA will allocate costs to the rate that applies to sales to preference customers and the loads of utilities (primarily IOUs) participating in the REP. Section 7(b)(1) expressly provides that REP costs can be allocated to BPA's rate for preference customers, which also applies to the REP:

> The Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest, *and loads of electric utilities under section 5(c)*. Such rate or rates shall recover the costs of that portion of the Federal base system resources needed to supply such loads until such sales exceed the Federal base system resources. Thereafter, such rate or rates shall recover the cost of additional electric power as needed to supply such loads, first from the *electric power acquired by the Administrator under section 5(c)* and then from other resources.

16 U.S.C. § 839e(b)(1) (emphasis added). The foregoing reference to "electric power acquired by the Administrator under section 5(c)" is a reference to the resources exchanged with BPA

under the REP, which, as noted above, is a program established in section 5(c) of the Northwest Power Act.

In simple terms, BPA first allocates the costs of FBS resources to preference customer and REP loads until the amount of the FBS is exhausted. When preference customer and REP loads exceed the FBS, BPA then is directed to allocate the costs of the exchange resources acquired under the REP to the preference customers' requirements loads and REP loads. Thus, the Northwest Power Act expressly directs BPA to allocate REP costs to BPA's preference customers' PF rate after first allocating FBS costs to such rate. This statement of the plain language of the Act must be reemphasized to ensure it is understood. The Northwest Power Act establishes there are circumstances (lack of sufficient FBS resources) where the Act expressly directs BPA to allocate REP costs to BPA's preference customers' PF rate. In the instant case, the FBS is insufficient to serve all of the requirements of the preference and REP customers. Because the amount of exchange resources acquired by BPA under section 5(c) is equal to the loads placed on BPA by participants in the REP, and the FBS exceeds preference loads, the total resources provided by the FBS and REP resources exceed the loads specified in section 7(b)(1).

Section 7(c) prescribes the manner in which BPA establishes rates for the DSIs:

> 839e(c)(1) The rate or rates applicable to direct service industrial customers shall be established—
>
> (A) for the period prior to July 1, 1985, at a level which the Administrator estimates will be sufficient to recover the cost of resources the Administrator determines are required to serve such customers' load and the net costs incurred by the Administrator pursuant to [16 U.S.C. 839c(c)], based upon the Administrator's projected ability to make power available to such customers pursuant to their contracts, to the extent that such costs are not recovered through rates applicable to other customers; and
>
> (B) 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.
>
> 839e(c)(2). The determination under paragraph (1)(B) of this subsection shall be based upon the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates but shall take into account—
>
> (A) the comparative size and character of the loads served,
>
> (B) the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions, and
>
> (C) direct and indirect overhead costs, as related to the delivery of power to industrial customers, except that the Administrator's rates during such

> period shall in no event be less than the rates in effect for the contract year ending on June 30, 1985.

16 U.S.C. § 839e(c). Section 7(c) prescribes different rate directives for DSI rates prior to and after July 1, 1985. Prior to July 1, 1985, the DSIs paid the cost of resources the Administrator determined were required to serve the DSIs' load and the net costs of the REP to the extent that such costs were not recovered through rates applicable to other customers. Thus, if preference customers were allocated REP costs after FBS resources proved inadequate to meet preference and REP loads, the DSIs did not pay the REP costs allocated to preference customers. After July 1, 1985, the DSIs' rates are based on BPA's power rates for preference customers and a typical margin included by preference customers in their retail industrial rates. *Id.*

BPA's other firm power rates are also subject to the effect of different rate directives after July 1, 1985. This occurs through the rate test established in section 7(b)(2) of the Northwest Power Act. During the development of the Northwest Power Act, preference customers were concerned about additional costs they would be required to pay under the new Act. Senator Jackson of Washington explained:

> Publicly owned utilities in the region and nationally have expressed concern that the proposed regional legislation adversely affects the preference clause. Northwest preference customers have sought to address this issue through amendments to establish a "preference customer rate limit" which would preserve the financial benefits of the preference clause for public agencies. The public power council amendments would require BPA to test the estimated power costs to preference customers under the bill against the costs which these customers would have encountered *in the absence of legislation.*
>
> A number of specific assumptions are set forth in the amendments which would guide BPA in making the determination of costs *in the absence of legislation*.

Cong. Rec. Senate, S3999 (April 5, 1979); *reprinted in* Legislative History at 526F (emphasis added); *see also* Cong. Rec. H2060 (April 5, 1979) (Congressman Duncan discusses the "'rate cap' amendment to ensure that preference customers will pay no more under this bill than they would without it"); *reprinted in* Legislative History at 528.

The preference customer amendments were the basis for sections 7(b)(2) and 7(b)(3) of the Act. Simply stated, the sections would test 1) preference customers' costs under the Act, with 2) preference customers' costs without the Act as established by a number of assumptions incorporated into section 7(b)(2). Senator Jackson's and Representative Duncan's remarks recognize the rate test was not solely a matter of protecting preference customers from the cost of the REP, but rather from "power costs to preference customers under the bill," which are reflected in the statutory language. *Id.* This is confirmed elsewhere in the legislative history.

The report of the Senate Committee on Energy and Natural Resources noted the rate test is a comparison of costs in the absence of the bill, not simply the REP:

> A rate test is provided in section 7 to insure that the Administrator's power rates for public bodies and cooperatives entitled to preference and priority under the

> Bonneville Project Act [are] no greater *than would occur in the absence of the regional program established in S. 885*.

S. Rep. No. 272, 96th Cong., 1st Sess. 20 (1979) (emphasis added). Thus, the purpose of the rate test is not to protect preference customers from the costs of the REP, but from the costs of the Act in excess of cost reductions arising from the Act.

The report of the House Committee on Interior and Insular Affairs characterized the test as generally ensuring costs benefits of preference rights, not simply precluding the allocation of REP costs:

> Subsection 7(b)(2) establishes a "rate ceiling" for BPA's preference customers, and specifies the method of calculating this ceiling, in order to insure such customers *the cost benefits of their preference rights for sales under this subsection.* Amounts not recoverable from preference customers because of this ceiling are to be recovered through supplemental rate charges for all other power sold by BPA under other provisions of section 7, as subsection 7(b)(3) specifies.

H.R. Rep. No. 96-976, Pt. II, 96th Cong., 2nd Sess. 52 (1980). This general intent is also recognized in the report of the House Committee on Interstate and Foreign Commerce. The report states:

> In addition, section 7(b) reserves for preference customers the price benefits for Federal power that they would have enjoyed *in the absence of this legislation*. This is accomplished by a "rate ceiling" which governs preference customer general requirements rates. Under this provision, the Northwest preference customers could pay less – but not more – for power under the legislation than they would have in any five-year period.

H.R. Rep. No. 976, Part I, 96th Cong., 2d Sess. 34 (1980) (emphasis added). The report also notes:

> Section 7(b)(2) establishes a "rate ceiling" for preference customers that seeks to assure these customers that their rates will be no higher than they would have been *had the Administrator not been required to participate in power sales or purchase transactions with non-preference customers under this Northwest Power Act*. The assumption[s] to be made by the Administrator in establishing this ceiling are specifically set forth. It is through rate ceilings that this Northwest Power Act provides additional protection to public bodies and cooperatives' preference customers as to the price of the sale of power by the Administrator. In the event that this rate ceiling is triggered, then the additional needed revenues must be recovered from BPA's other rate schedules.

Id. at 68-69; *see also* H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 36 (1980). This language recognizes BPA incurs costs under the Act due to BPA's "power sales" with "non-preference customers," such as BPA's sales to the DSIs, and "purchase transactions," and exchange purchases under the REP. This language also emphasizes something of critical importance. Although the legislative history speaks in general terms about a comparison of costs in the absence of the Northwest Power Act or some of the costs incurred thereunder, the report emphasizes that "[*t*]*he assumption*[*s*] *to be made by the Administrator in establishing this ceiling* *are specifically set forth*." In other words, the statutory language of section 7(b)(2), which requires BPA to incorporate *a number* of significant factors in conducting the rate test, governs the costs from which preference customers are protected. If the only purpose of section 7(b)(2) had been to protect preference customers from the costs of the REP, the test would have compared a case where the REP existed and a case where it did not. Congress did not choose to do so.

BPA acknowledges Congress intended to provide preference customers, in a general sense, protection from excessive REP costs. This is not the same thing as precluding the allocation of *any* REP costs to preference customers. The report of the House Committee on Interior and Insular Affairs states:

> … This [residential] exchange will allow the residential and small farm consumers of the region's IOUs to share in the economic benefits of the lower-cost Federal resources marketed by BPA and will provide these consumers wholesale rate parity with residential consumers [of] preference utilities in the region. Consumers of preference utilities will not suffer any adverse economic consequences as a result of this exchange since, as discussed below, the DSIs of BPA are required to pay the costs of the exchange during its initial years while a "rate ceiling" protects the customers of preference utilities during later years.

H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 35 (1980) (emphasis added). The foregoing language demonstrates the need to view such language in the context of the statutory rate directives. The report states preference customers would not suffer adverse consequences of the REP because "the DSIs of BPA are required to pay the costs of the exchange during its initial years." Reviewing the statutory language, however, it is true that the DSIs were expected to pay *the majority of costs of the REP* prior to July 1, 1985. Section 7(b)(1) of the Act, however, provides that REP costs can be allocated to preference customers' loads if the FBS resources become insufficient to meet such loads, and the DSIs do not pay the REP costs paid by other customers. 16 U.S.C. § 839e(b)(1). Thus, the report language is somewhat accurate, but is not in accord with the precise statutory requirements of section 7. Similarly, the report states that "a 'rate ceiling' protects the customers of preference utilities during later years," but the rate ceiling determines a trigger amount from *all of the factors* included in the rate test, not simply the REP. However, *in a general sense*, the rate test protects customers from REP costs because the REP costs are *part* of the calculation of the trigger amount.

The foregoing examination of the legislative history of the Northwest Power Act provides the context for reviewing section 7(b)(2) of the Northwest Power Act, which states:

> After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator assumes that—

(A) the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are—

(i) served by the Administrator, and

(ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives;

(B) public body, cooperative, and Federal agency customers were served, during such five-year period, with Federal base system resources not obligated to other entities under contracts existing as of the effective date of this Act (during the remaining term of such contracts) excluding obligations to direct service industrial customer loads included in subparagraph (A) of this paragraph;

(C) no purchases or sales by the Administrator as provided in section 5(c) were made during such five-year period;

(D) all resources that would have been required, during such five-year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were –

(i) purchased from such customers by the Administrator pursuant to section 6, or

(ii) not committed to load pursuant to section 5(b),

and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator; and

(E) the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from—

(i) reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, and

(ii) reserve benefits as a result of the Administrator's actions under this Act

were not achieved.

16 U.S.C. § 839e(b)(2).

In summary, the rate test involves the projection and comparison of wholesale power costs for general requirements of BPA's public body, cooperative, and Federal agency customers (7(b)(2) Customers) in two cases. The two sets of costs are: 1) a set for the test period and ensuing four years assuming that section 7(b)(2) is not in effect (Program Case rates); and 2) a set for the same period taking into account the five assumptions listed in section 7(b)(2), including adjustments to determine section 7(b)(2) general requirements (7(b)(2) Case rates). Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act are subtracted from the Program Case rates. Next, each nominal rate is discounted to the test year of the relevant rate case. The discounted Program Case rates are averaged, as are the 7(b)(2) Case rates. Both averages are rounded to the nearest tenth of a mill for comparison. If the average Program Case rate is greater than the average 7(b)(2) Case rate, the rate test triggers. Based on the extent to which the test triggers, the amount to be reallocated to non-PF Preference sales in the rate test period is calculated. 16 U.S.C. § 839e(b)(3).

As noted previously, section 7(b)(2) of the Northwest Power Act became applicable to BPA's rate development on July 1, 1985. *See* 16 U.S.C. §§ 839e(b)(2), 839e(b)(3), 839e(c)(1)(B), 839e(c)(2)(C). This section, however, does not repeal or eliminate the rate directives used to develop BPA's 1981 and subsequent power rates. Instead, the Act requires the rate test to be applied after the existing section 7(b)(1) rate directives. In order to conduct the rate test, BPA must first determine "the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative, and Federal agency customers" (the "Program Case rate"). This means BPA must first determine the rate to be charged preference customers using the rate directives of section 7(b)(1). In other words, BPA first allocates the costs of FBS resources to preference customer and REP loads until the amount of the FBS is insufficient to meet such loads. When the FBS "runs out," BPA then allocates the costs of the exchange resources to the preference customers' and REP loads in an amount needed to meet the loads not met by the FBS, and then, if necessary, costs from other resources. Thus, during the development of BPA's post-1985 power rates, including BPA's WP-02 and WP-07 power rates, BPA must allocate REP costs to the PF rate if the FBS is insufficient. In other words, prior to conducting the section 7(b)(2) rate test, the PF rate properly includes REP costs in the Program Case rates. Furthermore, sections 7(b)(2) and 7(b)(3) do not remove specific costs, such as REP costs, from the rates to preference customers; rather, the costs to preference customers are just limited to a certain amount. Therefore, even though the rate test lowers the rate to preference customers, it does not actually remove REP costs from the preference customer rate. REP costs remain in the rate, except in the extremely unusual event, which has never occurred in the history of ratemaking under the Northwest Power Act, that the FBS resources would be able to serve all preference customer and REP loads. Therefore, even though the 7(b)(2) Case rate does not contain any REP costs, the section 7(b)(3) rate protection does not eliminate REP costs from the Program Case rate.

This result is due to the 7(b)(2) Case rate being the same as the Program Case rate except for the exclusions to the Program Case rate and the Five Assumptions applied to the 7(b)(2) Case rate. (One of the Five Assumptions in the 7(b)(2) Case is that the REP does not take place.) BPA then compares the Program Case rate with the 7(b)(2) Case rate. If the Program Case rate exceeds the 7(b)(2) Case rate, the rate test triggers and the difference, the "trigger amount," must be allocated to rates other than the PF Preference rate through section 7(b)(3) of the Act.

It is possible for the section 7(b)(2) rate test to trigger even if no utility is participating in the REP. Assume, for example, a hypothetical case with no DSI loads in addition to no REP loads. If the FBS is not sufficient to meet the general requirements of preference customers, the costs of new resources are included in the preference customers' rates in proportion to the amount of new resources needed to meet preference customers' remaining general requirements. In the Program Case, the new resource costs will be the average cost of all new resources. In the 7(b)(2) Case, the new resource costs will be the least expensive resources in the section 7(b)(2)(D) resource stack. If the section 7(b)(2)(D) resource stack resources are cheaper than the average cost of all new resources, then the 7(b)(2) Case rates will be cheaper than the Program Case rates, causing the section 7(b)(2) rate test to trigger.

Section 7(b)(3) of the Northwest Power Act governs the allocation of costs in the event the section 7(b)(2) rate test triggers. Section 7(b)(3) provides that "[a]ny amounts not charged to public body, cooperative, and Federal agency customers by reason of paragraph (2) of this subsection shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers." 16 U.S.C. § 839e(b)(3). In other words, if the rate test triggers, the trigger amount must be allocated away from preference customers' power sales priced under section 7(b) to other power sales, including sales to utilities participating in the REP. These costs increase the PF Exchange rate, which is the rate at which BPA sells power to utilities participating in the REP. When the PF Exchange rate increases, the difference between that rate and the utility's ASC rate decreases, resulting in a reduction of REP benefits paid to the utility. Because each exchanging utility's ASC rate and residential load are different from those of other utilities, exchange benefits differ among participating utilities. A utility will receive no benefits when its ASC rate drops below BPA's PF Exchange rate.

Even if the trigger amount allocated to the PF Exchange rate does not raise the PF Exchange rate so high that REP benefits are completely eliminated, the PF Preference rate will still properly be recovering *some* REP costs. Thus, section 7(b)(2) does not protect the PF Preference rate from *all* REP costs, only from *additional* REP costs, and then, not by eliminating REP costs, but lowering non-specific costs allocated to the PF Preference rate. As noted previously, if Congress had intended to simply eliminate REP costs from the PF Preference rate, the section 7(b)(2) rate test would have been a comparison of a Program Case rate with the REP with a 7(b)(2) Case rate without the REP, *with no other differences between the two Cases*. Obviously, Congress did not do this.

Although REP costs are included in the Program Case and excluded from the 7(b)(2) Case, there are *numerous* other factors that Congress included in the rate test. These include the exclusion from the Program Case of costs of conservation, resource and conservation credits, experimental resources, and uncontrollable events and a different treatment for these costs in the 7(b)(2) Case; in the 7(b)(2) Case, Within and Adjacent DSI loads are included in the general requirements of preference customers; preference customers are served first with FBS resources not obligated under contracts in effect at the time the Act was signed; preference customers are served, after the FBS is exhausted, with either resources purchased from such customers by the Administrator or resources not committed to load under section 5(b) of the Act; and monetary savings from reduced financing costs and reserve benefits are not achieved.

It is this *combination* of *many* factors that produces the result of the rate test, not simply the REP. Some of the differences result in lower rates to preference customers, others in higher costs to preference customers. The REP, however, is the largest and most costly BPA program that is treated differently in the two Cases and therefore the primary focus of attention in assessing the effects of the rate test. Basically, when Congress established the REP, preference customers wanted some protection from the costs of the REP becoming extremely high and thereby excessively raising the PF Preference rate. In recognition that other aspects of the Northwest

Power Act provided benefits to preference customers, Congress chose to test the REP benefits against the other costs and benefits of the Act. The rate test addresses this balancing, but not by a test based solely on the REP or by a requirement that absolutely no REP costs be included in the PF Preference rate, but rather on a rate test based on a combination of factors. Indeed, the section 7(b)(2) rate test can 1) "trigger" even in the absence of REP costs, and 2) not "trigger" even with substantial REP costs.

This understanding is reflected in the legislative history of the Northwest Power Act. Appendix B to the Senate Report projected REP costs and cost allocations under the Act and demonstrated the understanding, from the inception of the Act, that projected REP costs (indeed, substantial projected REP costs) could be allocated to preference customers in the development of BPA's rates. S. Rep. No. 96-272, 96th Cong., 1st Sess. 56-79 (1979). The Senate base case analysis projected REP payments to IOUs for FY 1995 alone in excess of $750 million, without creating any trigger amount under section 7(b)(2). *Id*. at 69-71 (explanation: IOU Exchange rate [ASC, line 60] = 33.7, BPA PF Exchange rate [line 72] = 20.1, Exchange load [line 72] = 6,421 aMW; [33.7 -20.1=13.6 × 6,421 aMW × 8,760 [hours per year] = $765 million).

As discussed above, the portion of BPA's costs that remain allocated to preference customers may be limited by the section 7(b)(2) rate test, depending on the determination of the trigger amount in that test. Also as noted above, a trigger amount is not the same thing as removing REP costs because the trigger amount is determined using *all* of the Five Assumptions listed in section 7(b)(2). 16 U.S.C. § 839e(b)(2). When BPA calculates the trigger amount, BPA cannot quantify the synergy between the Five Assumptions that results in the trigger amount. It is not possible or meaningful to segregate the individual component contributions of any single section 7(b)(2) assumption to the trigger amount, because all five hypothetical assumptions must be made in concert. Thus, under sections 7(b)(2) and 7(b)(3), BPA removes the *trigger amount* from the costs allocated to the preference customers' rate, *not* REP costs. Similarly, under section 7(b)(3), when BPA reallocates the trigger amount to non-preference rates, BPA reallocates the *trigger amount* and *not* REP costs. The trigger amount, however, affects the costs properly allocated to the PF Preference rate.

BPA notes that its preference customers sometimes refer to section 7(b)(2) as a "rate ceiling." The legislative history of the Northwest Power Act does mention section 7(b)(2) operating as a "rate ceiling." *See* H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 36 (1980). It is important to recognize, however, that section 7(b)(2) does not establish an *absolute* rate ceiling on the PF Preference rate. BPA acknowledges that when it conducts the section 7(b)(2) rate test and a trigger amount is produced, the trigger amount is allocated to non-preference customers pursuant to section 7(b)(3). The PF Preference rate, after the allocation of the trigger amount to non-preference customers, is established at a specific level. This has been characterized as a "rate ceiling." However, section 7(b)(2) does not establish an *absolute* rate ceiling because, as recognized since the inception of the rate test, there may be circumstances where BPA's paramount statutory ratemaking requirement to recover its costs would govern over section 7(b)(2). Section 7(a)(1) of the Northwest Power Act provides that BPA's rates "shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power

System … and the other costs and expenses incurred by the Administrator." 16 U.S.C. § 839e(a)(1).

Section 7(a)(2) of the Northwest Power Act states that the Commission cannot approve BPA's rates unless the rates are 1) "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," 16 U.S.C. §839e(a)(2)(A), and 2) "are based upon the Administrator's total system costs…" 16 U.S.C. § 839e(a)(2)(B). Simply put, the cardinal statutory rule of BPA ratemaking is that BPA's rates *must* recover BPA's costs. If BPA's proposed rates do not recover BPA's total costs, they cannot be approved and implemented, and BPA cannot meet its obligations to the Treasury.

Before BPA had occasion to develop any power rates applying the 7(b)(2) test, BPA established the Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act, 49 Fed. Reg. 23,998 (June 8, 1984), to provide guidance on how BPA would harmonize section 7(b) with section 7(a). The Legal Interpretation was modified in the WP-07 Supplemental Rate Proceeding and provides that "implementation of section 7(b)(2), and any subsequent reallocation pursuant to section 7(b)(3), will not conflict with the requirements of section 7(a)." *See* Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act Legal Interpretation, WP-07-A-06, at 6. BPA's Legal Interpretation recognized that absent establishing rates in accordance with section 7(a), BPA's rates could not be confirmed and approved by the Commission and therefore could not be placed into effect. *See* 16 U.S.C. § 839e(a)(2). BPA concluded:

> The legislative history of the Northwest Power Act supports application of section 7(b) in a manner consistent with BPA's primary statutory obligation that its rates recover costs. The House Interior Committee report declares that:
>
> > Section 7 of the legislation sets out the requirements BPA must follow when fixing rates for the power sold its customers under this legislation. Subject to the general requirement (contained in section 7(a)) that BPA must continue to set its rates so that its total revenues continue to recover its total costs, BPA is required by the legislation to establish the following rates: [report continues by setting out rate structure of the Act]. H. Rep. No. 976, Part II, 96th Cong., 2d Sess. 36 (1980).
>
> Section 7(a)(2) illustrates the importance of BPA's statutory obligation to set rates at levels sufficient to collect its costs. Section 7(a)(2) states that FERC cannot approve BPA's rates unless the 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," 16 U.S.C. §839e(a)(2)(A), and "are based upon the Administrator's total system costs …" 16 U.S.C. § 839e(a)(2)(B).
>
> * * * *
>
> BPA is neither predetermining the results of the rate test nor suggesting a disregard for section 7(b)(2) with this discussion. BPA is not suggesting a solution to any problem arising from a potential conflict among sections 7(a),

> 7(b)(2), and 7(b)(3). BPA is merely attempting through this notice to alert its customers and the public to one possible problem which may present itself in the future. By raising the matter at this early date, BPA hopes that full discussion and consideration of such issues will enhance resolution of the problem when, and if, it arises in the context of the relevant rate case.

Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act Legal Interpretation, WP-07-A-06, at 6-7.

Such a condition could arise. In the hypothetical example begun above, if the costs of BPA's new resources exceeded the costs of the section 7(b)(2)(D) resource stack resources, a rate test trigger would occur, all other things being equal. In this case, assume there are no other loads to which to allocate the trigger amount. In such case, the preference customers would be due rate protection, but there would be no one to absorb the trigger amount. In such an instance, the trigger amount would necessarily be required to be paid by preference customers under section 7(a). In such an instance, the "rate ceiling" would be exceeded.

In addition, even if one were to assert the erroneous argument that there is a specific "rate ceiling" (because there are circumstances where this is not correct), it certainly does not limit the actual amount of REP benefits that may be provided during the rate period and therefore does not form a "cost ceiling." The difference between these two concepts is significant. A "rate ceiling" would be the maximum amount of forecast REP benefits allowed to be included in rates during a ratemaking proceeding. A "cost ceiling" would extend to the maximum amount that BPA could pay exchanging utilities in REP benefits.

However, REP benefits are determined *after* rates are established and in effect. There is no basis for a cost ceiling on the amount of REP benefits that BPA may actually pay in implementing the REP in any of BPA's statutes, GRSPs, policies, or procedures, and the REP benefit amount is subject only to the amount of benefits determined in such implementation. Further, the term "rate ceiling" does not occur in the Northwest Power Act; it is only referenced in the legislative history. The concept of a "cost ceiling" also does not occur in the Act. If Congress had intended that section 7(b)(2) would constitute a "cost ceiling," it would have said so. Indeed, just the opposite is true. In describing the rate test in section 7(b)(2), Congress directs BPA to look at "projected amounts," not amounts that will actually occur during the period following establishment of the rates. Thus, although section 7(b)(2) provides extensive rate protection to BPA's preference customers in the establishment of the PF Preference rate (through what is sometimes referred to as a "rate ceiling"), it does not establish a "cost ceiling."

The subsections that follow present the issues that were raised by rate case parties in their Initial Briefs concerning how the 7(b)(2) rate test was implemented in the development of BPA's proposed FY 2010-2011 power rates.

10.2 Conservation Savings Achieved Through Market Transformation and Conservation Rate Credit Efforts

Issue 1

What amount of conservation savings in service territories of BPA's preference customers should be included in the determination of the 7(b)(2) Case load augmentation amount and the amount of resources included in the section 7(b)(2)(D) resource stack?

Parties' Positions

The IOUs argue that any conservation funded by BPA in the service territories of BPA's preference customers should be treated as Type 1 resources, regardless of whether BPA pays the conservation funding to BPA's preference customers. IOU Br., WP-10-B-JP1-01, at 2. The IOUs also argue that if BPA-funded conservation savings in service areas of non-load following BPA preference customers are not Type 1 resources, then all conservation savings in such service territories must be Type 2 resources—whether funded by BPA or not. *Id*.

In their Brief on Exceptions, the IOUs claim that BPA improperly fails to include conservation funded by BPA in the service territories of BPA's preference customers in the section 7(b)(2)(D) resource stack. The IOUs state that BPA fails to do so based on two erroneous conclusions: 1) that conservation does not decrease the Administrator's load service obligations for non-load following preference customers; and 2) that only conservation that actually decreases the Administrator's load service obligations is includable in the section 7(b)(2)(D) resource stack. IOU Br. Ex., WP-10-R-JP1-01, at 10.The IOUs argue that BPA's treatment of conservation is also inconsistent with BPA's treatment of Power Resource Cooperative's 10-percent share of the output from the Boardman Coal Plant. *Id*.

APAC and PPC *et al.* argue that the conservation savings provided by market transformation programs are not resources "purchased from [preference] customers" and therefore cannot be included in the section 7(b)(2)(D) resource stack for the 7(b)(2) test. APAC Br., WP-10-B-AP-01, at 11; PPC *et al.* Br., WP-10-B-JP11-01, at 16. APAC also argues that conservation savings provided by the Conservation Rate Credit (CRC) program cannot be included in the section 7(b)(2)(D) resource stack for the 7(b)(2) test. APAC Br., WP-10-B-AP-01, at 12.

In its Brief on Exceptions, APAC argues that savings from the CRC program are not "resources," because the acquisition from the utility is not based on the amount of actual savings. APAC Br. Ex., WP-10-R-AP-01, at 5. APAC claims that under the CRC, all BPA is obtaining from the utility is the promise to expend a certain amount, and BPA then imputes to that expenditure an amount of deemed savings based on the programs utilized. *Id*. at 6.

BPA Staff's Position

The adjusted conservation savings in service territories of BPA's preference customers resulting from market transformation expenditures and BPA's CRC program pertaining to loads that can be reduced by these conservation efforts are included in 7(b)(2) Case load augmentation and in the section 7(b)(2)(D) resource stack. Doubleday *et al*., WP-10-E-BPA-39, at 8-13.

Evaluation of Positions

In determining the amount of conservation that should be included in the section 7(b)(2)(D) resource stack, BPA excludes a portion of market transformation conservation savings acquired through the Northwest Energy Efficiency Alliance (NEEA) that was not located in BPA's service territory, as well as the savings associated with non-load following BPA customer contracts. BPA excludes all of the conservation savings associated with BPA's C&RD program because the mechanisms that were used to document the savings did not provide us with sufficient confidence in the saving amounts for FY 2002-2006. BPA's CRC program (FY 2007-2015) has provided additional compliance and documentation requirements over conservation savings associated with the granting of CRC credits. BPA also excludes a portion of the conservation savings associated with the Conservation Rate Credits (CRC) program associated with non-load following BPA contracts during FY 2007-2015. These exclusions to the section 7(b)(2)(D) resource stack amounts also reduce the amount of 7(b)(2) Case load augmentation at the start of the rate test period. Study, WP-10-E-BPA-06, Appendix D. BPA excludes the portion of these conservation acquisitions that are associated with Slice and Block purchasers because the load these customers place on BPA is not reduced by the achieved conservation. Lacking a reduction in BPA's load to serve these customers, it follows that the load in the 7(b)(2) Case should not be augmented for such conservation.

The IOUs argue that all conservation savings in service territories of BPA's preference customers resulting from market transformation expenditures or BPA rate discounts should be included in 7(b)(2) Case load augmentation and in the section 7(b)(2)(D) resource stack. IOU Br., WP-10-B-JP1-01, at 23. The IOUs claim that, for example, all NEEA and other BPA-funded conservation, including the conservation from BPA conservation rate credits in BPA preference customer service territories, are includable in the 7(b)(2) Case as Type 1 resources. *Id.* (Type 1 resources are actual and planned resources acquired by BPA from 7(b)(2) Customers consistent with the Program Case. Type 2 resources are 7(b)(2) Customer resources not currently committed to regional loads.) The IOUs state that the effect of conservation in BPA preference customer service territories is to reduce the preference customers' net requirements (the amount of power the preference customers are entitled to purchase under section 5(b) under the Northwest Power Act). *Id.* at 24. Thus, the IOUs claim, any conservation in service territories of BPA preference customers that results from BPA expenditures and reduces the BPA preference customers' net requirements is, and should be treated as, Type 1 resources purchased by BPA. *Id.* Such BPA expenditures—even if not made to the preference customers—reduce the net requirements of the preference customers and thereby benefit BPA. *Id.*

The IOUs conclude that conservation savings in a BPA preference customer's service territory—whether a load following or non-load following customer—decrease the net requirements of that customer and thus provide a benefit to BPA and should be considered as Type 1 Resources. *Id.* at 25. The IOUs argue further that, in determining the projected costs in the 7(b)(2) Case of serving the general requirements of preference customers that are Slice or Block purchasers, there is no basis for assuming that such purchasers would purchase less than their full general requirements from BPA. *Id.* at 26. In such case, the IOUs claim, the conservation funded by BPA would indisputably reduce such purchases from BPA. *Id.*

BPA agrees with the IOUs' argument that conservation savings in service territories of BPA's preference customers resulting from market transformation expenditures or BPA rate discounts are Type 1 resources that have been acquired by BPA. BPA, however, disagrees with the IOUs' argument that Staff incorrectly reduces the amount of conservation savings available to meet 7(b)(2) Customer loads by excluding conservation savings that are limited by power purchase contract provisions. In determining the correct amount of market transformation conservation savings to include in the section 7(b)(2)(D) resource stack, Staff assumes that the current preference customer (Subscription) contracts that cover the term of October 1, 2001, through September 30, 2011, and which govern the sale and purchase of power in the Program Case, also govern the sale and purchase of power in the 7(b)(2) Case for the entire rate test study period (FY 2010-2015). This assumption follows the general approach established in BPA's Legal Interpretation: "The Administrator will exercise his discretionary authority in the following manner. Except for the Five Assumptions specified in section 7(b)(2), all underlying premises will remain constant between the Program Case and the 7(b)(2) Case." Section 7(b)(2) Rate Test Study, WP-10-E-BPA-06, Attachment 1, at 1. COUs with Block and Slice contracts are, in general, guaranteed the right to purchase a fixed amount of power under "take or pay" terms in their Subscription contracts. As such, they are allowed to remove resources from their contract to maintain their net requirement on BPA. The amount of power purchased cannot be reduced for conservation savings associated with C&RD, CRC, or Market Transformation conservation savings. Therefore, the IOUs are incorrect in their assumption that the market transformation and rate credit conservation acquisitions reduce the Slice and Block customers' net requirements.

Although BPA has purchased these conservation savings from COUs that occur in non-load following service territories, these conservation savings do not have the ability to reduce the Administrator's contractual load obligations under the terms of the Subscription contracts that govern both Cases. (BPA purchases of conservation from non-load following customers under Conservation Acquisition Agreements (CAAs) do reduce net requirements of such customers and are not at issue here.) Because the loads of COUs with Block and Slice contracts cannot be reduced in the Program Case for these conservation savings, there is no basis for increasing the loads in the 7(b)(2) Case for such savings. In projecting the amount of conservation resources available to the section 7(b)(2)(D) resource stack, BPA follows the over-arching principle that resources in the stack must have the ability to actually decrease the Administrator's load service obligations. Although the IOUs are correct in stating that conservation occurring in non-load following customer service areas exists independent of the utility's Block and Slice contracts, their argument ignores the fact that the power purchase contracts in the 7(b)(2) Case do not allow BPA to reduce their loads by these conservation savings. In contrast, conservation savings acquired through CAAs with individual non-load following COUs provide for reductions in power purchased amounts and therefore the savings and related costs are included in the section 7(b)(2)(D) resource stack.

In the alternative, the IOUs argue that under BPA's general approach to conservation, if BPA-funded conservation savings in service areas of non-load following BPA preference customers are not Type 1 resources, then all conservation savings in such service territories must be Type 2 resources—whether funded by BPA or not, and these conservation savings should, under BPA's general approach to conservation, augment the load in the 7(b)(2) Case and be included in the section 7(b)(2)(D) resource stack. IOU Br., WP-10-B-JP1-01, at 27. BPA does not need to address this alternative argument because it agrees with the underlying argument that the conservation resources in question would be Type 1 resources. However, lacking a basis to augment the 7(b)(2) Customer load, BPA will continue to exclude these conservation resources from the section 7(b)(2)(D) resource stack.

In an ideal world, the conservation savings (located in the service territories of customers with Slice and Block Subscription contracts that do not have other resources or other purchased power amounts) that are reducing the utility's incremental load growth would be quantified and would be included in the section 7(b)(2)(D) resource stack as Type 1 resources. There are a number of BPA customers that have not experienced load growth in their service territories since the inception of the Subscription contracts. The conservation savings associated with meeting incremental load growth would have to be determined on an individual customer basis and would take an extensive amount of Staff and customer resources. In the case of conservation savings associated with non-load following customers with Slice and Block Subscription contracts, which have other resources that are "freed-up" for resale as a result of the conservation savings, such Type 2 resources would also be quantified, with their amounts of power (aMW) and related costs included in the section 7(b)(2)(D) resource stack. However, there are problems identifying customers with multiple resources and power purchase contracts. There are similar problems with the determination of the portion of the resource sales that is attributable to being "freed-up" due to conservation savings. There are additional problems with Staff's ability to obtain the necessary resource cost information associated with those resources. Due to these problems, such resources cannot be objectively determined and have not been included in the section 7(b)(2)(D) resource stack for this rate case. This is consistent with the position stated in the IOUs' Initial Brief in the WP-07 Supplemental rate proceeding, which noted that "BPA must develop a full and complete justification for the resources to be included in the section 7(b)(2)(D) resource stack, information regarding these resources, and the appropriate costs attributable to those resources to be included in determining the 7(b)(2) Case costs." IOU Br., WP-07-B-JP6-01, at 27. Because this is the first time this argument has been raised, and because the IOUs did not raise this argument until their rebuttal testimony, there has been insufficient time to gather the resource information and allow other rate case parties an opportunity for discovery and rebuttal on those resource amounts and costs.

Under the Regional Dialogue contracts that take effect October 1, 2011, the amount of power purchased by a COU from BPA is the lower of its High Water Mark amount or the utility's net requirements at the start of every rate case. BPA expects that net requirements will be reduced for conservation savings; thus, there would be no reduction to conservation savings for non-load following loads in determining the 7(b)(2) Case load augmentation amount (or the amount contained in the section 7(b)(2)(D) resource stack), because such amounts will not exist under the new contracts during BPA's WP-12 rate case. Thus, gathering this information now would be relevant for only a limited time, would be burdensome, and would be precluded by the procedural inability to provide interested parties a full and fair opportunity to respond. Further, it would have only a *de minimus* effect on the 7(b)(2) rate test. As noted previously, increasing the 7(b)(2) Case loads for conservation savings that do not reduce customer loads in the Program Case would distort the rate test.

In their Brief on Exceptions, the IOUs reiterate the argument that BPA fails to recognize that BPA-funded conservation savings in service areas of preference customers are "resources" acquired by BPA that should be included in the section 7(b)(2)(D) resource stack, regardless of whether such conservation savings reduce a preference customer's net requirement or purchases from BPA in the Program Case. IOU Br. Ex., WP-10-R-JP1-01, at 8-12. The IOUs note that BPA proposes to exclude from the section 7(b)(2)(D) resource stack BPA-funded conservation savings in service areas of non-load following BPA preference customers. *Id*. at 8-9, *citing* Draft ROD, WP-10-A-01, at 102. The IOUs conclude that BPA thus appears to recognize that BPA-funded conservation savings in service areas of non-load following BPA preference customers are Type 1 resources, but somehow erroneously conclude that, despite such conservation savings being Type 1 resources, 7(b)(2) Case loads should not be increased by the amount of such savings and they should be excluded from the section 7(b)(2)(D) resource stack. *Id*. at 9.

The IOUs note that the Northwest Power Act defines "resource" as including "actual or planned load reduction resulting from direct application of a renewable energy resource by a consumer, or from a conservation measure." IOU Br. Ex., WP-10-R-JP1-01, at 9. The IOUs conclude that conservation savings in the service territories of non-load following BPA preference customers constitute "resources" regardless of whether such conservation savings reduce the net requirements of those BPA preference customers. *Id*. The IOUs argue that if BPA funds conservation, it is acquired by BPA pursuant to section 6 of the Northwest Power Act and must be included in the section 7(b)(2)(D) resource stack. *Id*. The IOUs note that the Legal Interpretation determined that conservation acquired by BPA is a Type 1 resource. *Id*., *citing* Study, WP-10-E-BPA-06, Attachment 1, at 10. The IOUs argue that under section 7(b)(2), resources purchased from preference customers by the Administrator pursuant to section 6 of the Northwest Power Act must be included in the section 7(b)(2)(D) resource stack; there is no additional requirement that, as suggested in the Draft ROD, such resources (conservation savings) must "actually decrease the Administrator's load service obligations." IOU Br. Ex., WP-10-R-JP1-01, at 9. The IOUs claim that BPA improperly fails to include such resources based on two erroneous conclusions: 1) that conservation does not decrease the Administrator's load service obligations for non-load following preference customers; and 2) that only conservation that *actually* decreases the Administrator's load service obligations is includable in the section 7(b)(2)(D) resource stack. *Id*.

BPA does not dispute that conservation is a resource or that BPA acquires conservation from public bodies and cooperatives pursuant to section 6 of the Northwest Power Act. BPA also does not dispute that the Legal Interpretation describes such conservation as a Type 1 resource. BPA's treatment of conservation in implementing the rate test, however, is based on the agency's interpretation of the complex rate directives in section 7(b)(2). BPA's lengthy analysis of such treatment has been previously discussed. *See also* WP-07 Supplemental ROD, WP-07-A-09, at 429-471. The IOUs' argument cannot be reviewed in the absence of considering the manner in which BPA treats conservation in implementing section 7(b)(2).

The amount of conservation in the 7(b)(2) Case determines 1) the amount of load augmentation that occurs in the 7(b)(2) Case for conservation investments that are assumed to have not occurred in the 7(b)(2) Case, and 2) the amount of conservation resources that are available to meet 7(b)(2) Case loads after all FBS resources have been applied to 7(b)(2) Case loads (if conservation is the least-cost resource). In quantifying the amount of conservation resources that are assumed to have not yet occurred in the 7(b)(2) Case and thereby increase 7(b)(2) Case loads, BPA *does not* increase the 7(b)(2) Case loads for *all* conservation investments that were acquired pursuant to section 6 of the Act. First, BPA properly excludes all conservation resources that have been determined to be obsolete. The reason these conservation resources are excluded is that they are no longer reducing the Administrator's load obligations in the Program or 7(b)(2) Case. Similarly, BPA excludes the aforementioned conservation resources occurring in COU service territories that are governed by the Subscription Block and Slice contracts used in both the Program and 7(b)(2) Cases. These Subscription contracts establish fixed load commitments associated with purchases of fixed blocks of power and/or the Slice product. For simplicity, these sales are referred to as non-load following contracts. Conservation resources occurring in service territories with non-load following contracts do not reduce the Administrator's load obligations in the 7(b)(2) Case. In addition, BPA excludes conservation resources associated with the C&RD program because there was not adequate documentation surrounding the conservation savings associated with this program to ensure that these resources could meet the Administrator's load obligations in the 7(b)(2) Case.

BPA disagrees with the IOUs' argument that there is no requirement that conservation savings must have the ability to meet the Administrator's load service obligations in the 7(b)(2) Case. BPA's responsibility in performing the 7(b)(2) rate test is to objectively determine the amount of conservation resources that are available to serve 7(b)(2) Case loads. It would be absurd to populate the section 7(b)(2)(D) resource stack with resources that could not meet the loads in that Case. Similarly, it would cause a distortion in the rate test to artificially increase loads in the 7(b)(2) Case by conservation savings that have no ability to meet the loads in that Case due to the Subscription contract provisions governing the 7(b)(2) Case. In BPA's WP-07 Supplemental rate proceeding, the record of which has been included in the BPA-10 proceeding record, the IOUs' Initial Brief concerning resources included in the section 7(b)(2)(D) resource stack stated that

> section 7(i)(5) of the Northwest Power Act requires the BPA administrator to make a "final decision establishing a rates based on the record," and such decision "shall include a full and complete justification of the final rates pursuant to [section 7]." 16 U.S.C. § 839e(i)(5). Pursuant to these statutory provisions, BPA must develop a full and complete justification for the resources to be included in the 7(b)(2) resource stack, information regarding these resources, and the appropriate costs attributable to those resources to be included in determining the 7(b)(2) Case costs. … For example, BPA must demonstrate that (i) any resource included in the 7(b)(2) Case resource for any portion of the Five-Year Period is, in fact, a resource that is projected to be operating (*e.g.*, not obsolete) during such Five-Year Period, and (ii) the costs in the 7(b)(2) case resource stack of any such resource are, in fact, the projected costs of such resource.

IOU Br., WP-07-B-JP6-01, at 27-28. Thus, the IOUs' position in the WP-07 Supplemental rate proceeding was that resources had to be operating and not obsolete. This supports BPA's position in the present case that conservation resources have to be able to reduce the Administrator's load obligations in the 7(b)(2) Case. The IOUs' present position, that "there is no additional requirement that conservation savings actually have the ability to meet the

Administrator's load service obligations in the 7(b)(2) Case," is inconsistent with their position concerning resources to be included in the section 7(b)(2)(D) resource stack in the WP-07 Supplemental rate proceeding. BPA consistently excluded conservation savings associated with non-load following loads in the WP-07 rate proceeding and the WP-07 Supplemental rate proceeding. No party in those proceedings objected to BPA's treatment to exclude conservation savings from non-load following COUs' service territories from the section 7(b)(2)(D) resource stack based on the reasoning that those savings could not reduce the Administrator's load obligations in the 7(b)(2) Case.

The IOUs argue that BPA's treatment of conservation is inconsistent with BPA's treatment of Power Resource Cooperative's 10-percent share of the output from the Boardman Coal Plant. IOU Br. Ex., WP-10-R-JP1-01, at 10. The IOUs state that BPA excludes from the section 7(b)(2)(D) resource stack conservation in the service territories of non-load following preference customers because BPA (contrary to the arguments of the IOUs) concludes that the loads of such customers cannot be reduced *in the Program Case* for such conservation. *Id.* at 10-11, *citing* Draft ROD, WP-10-A-01, at 102 ("Because the loads of COUs with Block and Slice contracts cannot be reduced *in the Program Case* for these conservation savings, there is no basis for increasing the loads in the 7(b)(2) Case for such savings."). The IOUs claim that BPA applies a different, inconsistent rationale with respect to BPA's decision to include the output from Power Resources Cooperative's 10-percent share of the Boardman Coal Plant, where BPA argues that the output that has been actually sold outside the region is properly included in the section 7(b)(2)(D) resource stack because it would not have been so sold in the 7(b)(2) Case. IOU Br. Ex., WP-10-R-JP1-01, at 11, *citing* Draft ROD, WP-10-A-01, at 139. The IOUs claim that BPA fails to explain these inconsistent approaches and does not point to substantial evidence in the record considered as a whole that supports these inconsistent approaches. IOU Br. Ex., WP-10-R-JP1-01, at 11-12. The IOUs state that under the logic applied by BPA in the case of Boardman output, BPA should increase the general requirements in the 7(b)(2) Case for BPA-funded conservation that occurs in service areas of non-load following BPA preference customers, even assuming *arguendo* that such conservation savings do not decrease the net requirements or purchases from BPA of such preference customers in the Program Case. *Id.* at 12.

BPA disagrees with the IOUs' argument that BPA has taken inconsistent positions in excluding conservation savings from the section 7(b)(2)(D) resource stack associated with non-load following loads, and including the Boardman resource output owned by preference customers. Conservation resources are included in the section 7(b)(2)(D) resource stack as Type 1 resources (resources purchased from public bodies and cooperatives by the Administrator pursuant to section 6 of the Northwest Power Act). As outlined above, BPA has consistently excluded conservation resources associated with non-load following contracts from the 7(b)(2) Case because the contracts governing the purchase of power in the 7(b)(2) Case do not reduce the power purchase commitments for the CRC and market transformation conservation savings that occur during the time the Subscription power contracts are in effect. This consistent approach was used in the WP-07 and WP-07 Supplemental rate cases in addition to the current rate case. As noted previously, when the Regional Dialogue contracts become effective in FY 2012, there should be no reduction in conservation resources, because those contracts should allow for conservation savings to reduce the Administrator's load obligation.

In contrast to BPA's exclusion of conservation resources because such resources do not have the ability to reduce the Administrator's load obligations, BPA includes 10 percent of the Boardman resource output in the 7(b)(2) Case as a Type 2 resource (existing 7(b)(2) Customer resources not currently committed to regional customers or IOUs). This is because the 7(b)(2) Customers would have used the resources they already own in the 7(b)(2) Case to meet their loads in excess of FBS resource capability. BPA has included the Boardman resource in the section 7(b)(2)(D) resource stack since the WP-93 rate case. Because BPA's respective exclusion and inclusion of these two distinct resource types from the section 7(b)(2)(D) resource stack are determined independently, are based on separate statutory requirements and facts, and have been consistent over successive rate cases, BPA's treatments are not inconsistent. Contrary to the IOUs' assertion that there is not sufficient evidence on the record for these two independent determinations, BPA has explained the basis for such determinations in the full record applicable to this proceeding.

In contrast to the IOUs, APAC argues that certain conservation programs are not eligible for the section 7(b)(2)(D) resource stack. APAC Br., WP-10-B-AP-01, at 11. APAC states that section 7(b)(2)(D) of the Northwest Power Act requires that resources used to satisfy load in the 7(b)(2) Case either be purchased from public bodies, cooperatives and federal agencies or not committed to load under Section 5(b). *Id.* APAC asserts that the conservation savings provided by market transformation programs are not resources purchased from preference customers and therefore cannot be included in the section 7(b)(2)(D) resource stack for the 7(b)(2) test. *Id.* APAC claims that because BPA is purchasing savings through NEEA from consumers, not from customers, these programs do not meet the section 7(b)(2)(D) requirements. *Id.* Also, APAC notes, the NEEA program purchases are made from consumers in IOU service areas as well as consumers in COU service areas, and it would be improper for BPA to include purchases from IOU consumers in the costs of the market transformation resource. *Id.* at 12.

PPC *et al.* agree with APAC that savings categorized under market transformation should not be included in the section 7(b)(2)(D) resource stack. PPC *et al.* Br., WP-10-B-JP11-01, at 16. PPC *et al*. states that section 7(b)(2)(D)(i) is specific in citing resources purchased from public body, cooperative and Federal Agency customers, and NEEA is not a public body, cooperative, or Federal Agency customer of BPA. *Id.* at 17.

Staff disagrees with APAC's and PPC's suggestion that market transformation conservation savings and CRC savings should not be included in load augmentation in the 7(b)(2) Case and should not be included in the section 7(b)(2)(D) resource stack. Doubleday *et al.*, WP-10-E-BPA-39, at 8-13. Prior to directly addressing APAC and PPC's arguments, it is helpful to review the context of BPA's conservation acquisitions.

The gross amount of market transformation savings is contained in BPA's Conservation Resource Energy Data publications (the RED Book). The RED Book amounts are analyzed and adjusted by Appendix D. Documentation, WP-10-E-BPA-06A, at D-20 – D-22. Appendix D quantifies the amount of savings that is not associated with BPA's service territory (*i.e.*, IOU service territories) and the amount of savings served by non-load following customer contracts (*i.e.*, Slice and Block customers). *Id.* The savings associated with both are appropriately subtracted from the "gross savings" amounts in arriving at the "adjusted savings" amounts that are included in the section 7(b)(2)(D) resource stack. *Id.* The actions BPA takes to acquire conservation are described in the Northwest Power Act. Doubleday *et al.*, WP-10-E-BPA-39, at 8-13. For example, section 6(a)(1) directs the Administrator to acquire conservation resources that are consistent with the Northwest Power and Conservation Council's Plan. *Id.* Section 6(a)(1)(B) of the Northwest Power Act states that BPA is to provide "technical and financial assistance to, and other cooperation with, the Administrator's customers and governmental authorities to encourage maximum cost-effective voluntary conservation…." *Id.* Section 6(b)(5) states that "the Administrator shall not reduce his efforts to achieve conservation and to acquire renewable resources installed by a residential or small commercial consumer to reduce load, pursuant to subsection (a)(1) of this section." *Id.* Section 6(e)(1) states that to effectuate the priority given to conservation measures, the Administrator shall make use of his authorities to acquire conservation measures, implement conservation measures, and provide credits and technical and financial assistance for the development and implementation of conservation measures. *Id.* Section 6(e)(2) recognizes that to the extent conservation measures or the acquisition of resources require direct arrangements with consumers, the Administrator shall make maximum practicable use of customers and local entities capable of administering and carrying out such arrangements. *Id.*

BPA is properly providing market transformation support to NEEA to assist BPA's efforts to provide the most cost-effective means of developing and implementing conservation savings. *Id.* NEEA is a regionally supported entity that provides direct assistance to BPA's utility customers and their retail consumers, including BPA's preference customers. *Id.* Through BPA's financial support of NEEA, BPA achieves energy savings associated with, among other technologies, energy-efficient appliances and compact fluorescent light (CFL) bulbs from 7(b)(2) Customers' residential and small commercial consumers. *Id.* Indeed, NEEA's efforts achieve conservation savings across the entire Pacific Northwest region. *Id.* NEEA's region-wide programs provide an economy of scale and related cost-effectiveness that can be achieved only through BPA's large financial commitment to NEEA on behalf of all of BPA's customers. *Id.* These benefits result in a reduction in electricity demand on the local utility, which in turn delivers energy savings (otherwise known as conservation) to BPA. *Id.* Thus, acquiring conservation through market transformation is a means by which BPA can purchase conservation savings from its public body and cooperative customers pursuant to section 6 of the Northwest Power Act. *Id.*

Conservation savings acquired through NEEA's market transformation efforts are some of "the least expensive conservation resources" within public bodies or cooperatives' service territories. *Id.* As noted above, BPA's NEEA conservation expenditures allow the acquisition of demonstrated savings through reduced 7(b)(2) Customers' loads, achieved by encouraging retail consumers (consumers of energy-efficient products) to invest in energy-efficient appliances and CFLs. *Id.* The value to BPA and its utility customers is that the acquisition or purchase of more expensive generating resources is delayed or avoided. *Id.* The commitment to conservation resources and the achievement of those savings in 7(b)(2) Customers' service territories through the directives of the Northwest Power Act would not have occurred in the hypothetical world of section 7(b)(2), where such commitment required by the Act would not have occurred. *Id.* In substance, there is no difference in BPA's practice of funding NEEA's efforts to acquire conservation savings from 7(b)(2) Customer service territories compared to BPA providing monies directly to COUs to promote and foster their own conservation programs. *Id*.

The 7(b)(2) rate test compares Program Case costs with 7(b)(2) Case costs. *Id*. In the 7(b)(2) Case, only certain types of resources are used to serve public body, cooperative, and Federal agency loads: stated simply, resources that are available for use because they are not contractually committed to regional firm load, and resources that BPA purchased from such customers. *Id*. This means that additional resources needed to meet load in the 7(b)(2) Case, in general terms, would be incremental to those of the public body, cooperative, and Federal agency customers themselves. *Id*. If BPA pays money directly to such customers to acquire conservation savings from them, BPA acquires the conservation resource from them. *Id*. If BPA pays NEEA to establish programs to obtain conservation savings from the same customers or from their retail consumers, BPA still acquires the conservation resource from such customers. *Id*. The fact that BPA employs an agent to acquire conservation from public body, cooperative and Federal agency customers does not mean that BPA has not purchased the conservation from such customers. *Id*. In reality, BPA's customers do not provide the actual conservation savings. They too are agents, much like NEAA, and acquire conservation savings from their retail consumers.

BPA's decision to acquire conservation savings from COUs' service territories through market transformation efforts, which depend on large region-wide program efforts to have the greatest impact in the most cost-effective manner, is consistent with the intent of the provisions of section 6 of the Act. BPA's efforts to acquire the most cost-effective conservation consistent with the provision of section 6 of the Act should not be frustrated with an interpretation of section 7(b)(2)(D) that would exclude these conservation savings from serving 7(b)(2) Customer loads and by direct implication reduce BPA's capability of providing REP benefits to utilities under section 5(c) of the Act. As provided in BPA's Legal Interpretation of Section 7(b)(2),

> Basic principles of statutory construction must be followed in interpreting the Northwest Power Act. These principles require that particular provisions of a statute be interpreted to give effect to its overall purposes. *United States v Am. Trucking Ass'n*, 310 U.S. 534, 543 (1950). Wherever possible, statutory provisions should be construed so as to be consistent with each other. *Adams v. Howerton*, 673 F.2d 1036, 1040 (9th Cir. 1982), *cert. denied*, 458 U.S. 1111 (1982). Thus, BPA interprets the Northwest Power Act in a manner that seeks consistency among the requirements of each section of Northwest Power Act.

Study, WP-10-E-BPA-06, Attachment 1, at 1. The framers of the Act would not have distinguished the difference in conservation savings achieved in a COU's service territory that is achieved through BPA's support of the conservation efforts of an intermediary (NEEA), as opposed to direct conservation acquisition savings that are achieved by BPA's support for COUs' conservation efforts, in determining which conservation savings should be included or excluded from the section 7(b)(2)(D) resource stack. Again, in substance, there is no difference to BPA's practice of funding NEEA's efforts to acquire conservation savings from 7(b)(2) Customer service territories as compared to BPA providing monies to COUs to promote and foster COU conservation programs in their service territories.

In its Brief on Exceptions, APAC notes that it previously argued that market transformation savings are not "purchased from" preference customers as required by section 7(b)(2)(D) of the Northwest Power Act. APAC Br. Ex., WP-10-R-AP-01, at 3. APAC states that much of the response to this issue in the Draft ROD seems to be justifying BPA's funding of the market transformation program. *Id*. APAC states that it is not arguing that the expenditures should not have been made; rather, in performing the 7(b)(2) rate test, these expenditures should not be included in the section 7(b)(2)(D) resource stack. *Id*. BPA understands this distinction, but the background of the program continues to be relevant to the issue of whether market transformation expenditures are purchased from preference customers.

APAC argues that section 7(b)(2) says nothing about whether BPA should be incurring the actual costs, as those 7(g) costs are subtracted from the Program Case before the rate test is even performed; rather, section 7(b)(2) governs only the ratesetting determination of what "rate ceiling" should be imposed on preference customers. APAC Br. Ex., WP-10-R-AP-01, at 4.

APAC states that the Draft ROD seeks to equate purchasing from customers *(i.e.*, utilities) with purchasing from consumers, noting "[t]he fact that BPA employs an agent to acquire conservation from public body, cooperative and Federal agency customers does not mean that BPA has not purchased the conservation from such customers." *Id*. APAC asserts that this statement is not true, because BPA's agent, NEEA, does not acquire conservation from public body, cooperative, or Federal agency customers, but instead bypasses those customer utilities and acquires conservation directly from end-users. *Id*. APAC claims that regardless of the merits of the program, Congress did not include such programs as "resources" to be included in the section 7(b)(2)(D) resource stack. *Id*. at 4-5. BPA disagrees. Public body and cooperative customers each own a conservation resource. This conservation resource is the amount of savings that can be obtained *from the customer's end-use consumers*. Under a direct purchase of conservation from a preference customer (which APAC acknowledges is properly included in the section 7(b)(2)(D) resource stack), BPA purchases savings from the customer's end-use consumers, not conservation from the utility itself (which might be limited to savings from a building or two). The same is true for conservation BPA acquires through NEEA. NEEA obtains conservation from the end-use consumers of preference customers. This is the same conservation BPA would acquire under a direct purchase agreement with the utility. Thus, BPA can purchase conservation from a utility through a direct contract with the utility or indirectly through a contract with an agent that acquires the same conservation from the utility that would be acquired through a direct agreement. In either case, it is the preference customers' net requirement that is reduced by such conservation. This is the fatal flaw in APAC's argument. For purposes of section 7(b)(2), resources purchased by BPA from preference customers are properly included in the section 7(b)(2)(D) resource stack. 16 U.S.C. § 839e(b)(2)(D)(i). Conservation is a resource. 16 U.S.C. § 839a(19)(B). It would make no sense to include preference customers' conservation resources (which are obtained from the preference customers' end-users) in the section 7(b)(2)(D) resource stack when purchased by BPA through a direct agreement with a preference customer, but to exclude the same preference customers' conservation resources (which are obtained from the same preference customers' end-users) from the section 7(b)(2)(D) resource stack when obtained by a BPA agent from the same preference customers' end-users, and thus from the preference customers.

APAC argues that the *form* of the acquisition should be determinative as to whether conservation savings should be included in the section 7(b)(2)(D) resource stack, not the *substance* that conservation savings are being acquired in the service territories of BPA's preference customers. As noted above, APAC's argument ignores that all conservation savings occur in end-user homes and businesses. Market transformation savings provide an economic benefit to the end-use consumer in the form of lower energy consumption/costs while still achieving the same level of efforts/benefits. Market transformation savings have value to BPA and its COU customers: they preserve the competitive position of regional utilities by decreasing the need to invest in more-expensive generating resources. Under market transformation, neither BPA nor the COUs acquire a property right in a tangible asset that can be exchanged for value. The expenditure has provided a *public benefit* for all customers in the region, particularly in BPA's load service territory. Given the nature of conservation savings, BPA does not view the form of how conservation savings are acquired as solely determinative of the conservation savings eligible for inclusion in the section 7(b)(2)(D) resource stack. As discussed above, in determining the amount of conservation resources included in the section 7(b)(2)(D) resource stack, BPA follows the over-arching principle that resources in the stack must have the ability to actually decrease the Administrator's load service obligations.

In summary, the purpose of section 7(b)(2)(D)(i) of the Northwest Power Act is to include in the section 7(b)(2)(D) resource stack those resources BPA acquires from its public body and cooperative customers pursuant to section 6 of the Act. Conservation is a resource. 16 U.S.C. § 839a(19)(B). Market transformation is a form of conservation. Market transformation savings are available from public body and cooperative customers due only to the existence of savings available from such customers' end-use consumers. BPA has established a means of acquiring public body and cooperative customers' conservation, which is their end-use consumers' conservation, through an arrangement with NEEA. The inclusion of market transformation savings in the section 7(b)(2)(D) resource stack is perfectly consistent with the intent of section 7(b)(2)(D)(i) of the Act. Failure to include such conservation resources in the section 7(b)(2)(D) resource stack would be contrary to the logical operation of the rate test.

In its Brief on Exceptions, APAC reiterates its argument that the amount of market transformation savings used as a resource includes savings occurring in IOU service territories, which are not preference customers. APAC Br. Ex., WP-10-R-AP-01, at 5. APAC notes that the Draft ROD suggests that the amount of savings from these programs was adjusted to remove savings occurring in IOU territories, but APAC quotes cross-examination testimony in apparent conflict. *Id.* APAC suggests that this issue should be clarified in the final studies and in the Final Record of Decision to ensure that savings from IOU consumers are not included in the section 7(b)(2)(D) resource stack. *Id.* In response, BPA affirms that it has adjusted the amount of savings from market transformation programs to remove savings occurring in IOU territories. *See* Section 7(b)(2) Rate Test Study Documentation, WP-10-FS-BPA-06A, Appendix D at D-20 – D-22, and Note 3 on page D-23.

APAC also argues that savings from BPA's CRC program, in addition to market transformation conservation savings, are not resources purchased from preference customers. APAC Br., WP-10-B-AP-01, at 12. APAC notes that the CRC program is available to customers under several of BPA's rate schedules. *Id.* The customer satisfies its obligations under the program if the amount of the total rate credit granted is equal to or less than the utility's "qualifying expenditures." *Id*. If a utility receives $1000 in rate credits, BPA is purchasing from that utility the commitment to make $1000 in expenditures for conservation programs. *Id*. APAC argues, however, that BPA is not purchasing any specified amount of load reduction. *Id*. APAC asserts the section 7(b)(2)(D) resource stack used in the 7(b)(2) rate test is composed of resources purchased from such customers, and the definition of "resource" includes "actual or planned load reduction…." *Id*. APAC argues that under these statutory requirements, the Administrator must purchase from the utility a specified load reduction; merely purchasing from the utility a commitment to spend money does not qualify as a "resource." *Id*. APAC concludes that the load reduction attributable to the CRC program should not be included as a resource used in the section 7(b)(2)(D) resource stack. *Id*. at 12-13.

For many of the same reasons noted above concerning market transformation conservation savings, BPA disagrees with APAC's proposal to exclude conservation savings obtained through BPA's CRC program (FY 2007-2015) from the section 7(b)(2)(D) resource stack. Doubleday *et al*., WP-10-E-BPA-39, at 11-13. (Savings attributable to BPA's Conservation Rate Discount Program FY 2001-2006 were removed from the section 7(b)(2)(D) resource stack amounts as explained in the Study, WP-10-E-BPA-06, at D-18, Note 4.) *Id*. BPA also disagrees with APAC's premise that use of the rate credit mechanism does not constitute a purchase by BPA from respective consumer-owned utilities. *Id*.

The CRC is described in BPA's 2010 Wholesale Power Rate Schedules and 2010 General Rate Schedule Provisions (GRSPs), Appendix B to this ROD, WP-10-A-02, Section II.A., and is supported by the testimony of Ingram *et al*., WP-10-E-BPA-17. The CRC is unlike generic sales discounts used in business, which are generally a stated percentage discount of the gross sales on a transaction that is based on the quantity of purchases or payment within a prescribed time period. Doubleday *et al*., WP-10-E-BPA-39, at 11-13. As described in the GRSPs, the monthly CRC credit (purchase) amount is determined by each customer's average monthly forecast load over the 24-month rate period multiplied by 0.5 mills/kWh. *Id*. Thus, the credit is based on the relationship of the amount of energy that is forecast to be purchased, which is related to the conservation savings potential in each customer's load service area. *Id*. Providing the CRC to BPA's utility customers creates an incentive to the utility, and an obligation of the utility, to develop and acquire qualified conservation saving programs that are outlined in the CRC Implementation Manual. *See* http://www.bpa.gov/Energy/N/pdf/CRC-CAA_Imp-Manual_04-01-2009_FINAL.pdf. *Id*. The manual is specific as to which conservation expenditure efforts qualify under the CRC program. Thus APAC's argument that BPA is merely purchasing a utility commitment to spend money misrepresents the controls that exist to ensure that approved conservation measures are being acquired. Customers can elect not to take part in the CRC program and thereby not receive CRC monies through their power bills. *Id*. There are no penalties for customers that do not participate in the CRC. *Id*. Customers that do participate must submit reports on their CRC expenditures into the Planning, Tracking, and Reporting (PTR) system. *Id*. The CRC expenditures are correlated with the energy savings attributed to each energy conservation measure that is reported. If the total CRC-qualifying expenditures are less than the total accumulated monthly credits, the customer is required to reimburse BPA for the difference. *Id*.

BPA, with input from its customers, adopted the payment method of placing a credit on the utilities' bills because it was more efficient and less costly than issuing a separate check or other form of payment to the utility, and it helped utilities to budget their conservation expenditures in their service territories. *Id*. From an accounting standpoint, the receipt of the credit on a power bill is the same as if a check had been issued. *Id*. From the utility's standpoint, it records a reimbursement for conservation expenditures already undertaken (credit a receivable), or it credits a liability for expenditures that it is obligated to incur. *Id*. The power purchase expense (debit) should be recorded at the gross amount. *Id*. For the year, BPA's CRC payments offset a utility's annual conservation expense or offset the amount that would be capitalized and recovered through annual amortization charges. *Id*. From BPA's perspective, the payment of the CRC is recorded as an annual operating expense associated with BPA's conservation program. *Id*. The CRC payments are included in the annual operating expenses contained in BPA's revenue requirements, which are recovered through BPA's power rates. *See* Study, WP-10-E-BPA-06, at B-10, line 14 (the composition of line 18 of the Program Case COSA – annual conservation expense). *Id*.

From the perspective of BPA's utility customers, treating the CRC as a credit that reduces the cost of power purchased by the utility would not be supported by Generally Accepted Accounting Principles. *Id*. As noted above, the CRC monies establish an obligation on the part of the utility to undertake conservation expenditures, which are an operating expense of the period or an investment in an intangible asset (conservation savings). *Id*. Thus, it would be inappropriate to subtract the CRC monies from power purchase expenses. APAC's argument that the form of BPA's payment as a credit on monthly power bills does not constitute an amount of compensation or "purchase from such customers by the Administrator pursuant to section 6" is simply incorrect. *Id*.

Furthermore, the statutory provisions APAC cites do not support its argument. It is true that resources are included in the section 7(b)(2)(D) resource stack and the definition of resource includes "actual or planned load reduction…." 16 U.S.C. § 839a(19)(B). However, there can be little dispute that BPA acquires actual or planned conservation through the CRC. The fact that conservation is acquired is sufficient to satisfy the statutory language.

In its Brief on Exceptions, APAC reiterates its argument that the savings attributable to the CRC program should not be included in the section 7(b)(2)(D) resource stack. APAC Br. Ex., WP-10-R-AP-01, at 5-6. APAC argues that savings from the CRC program are not "resources" because the acquisition from the utility is not based on the amount of savings. *Id*. APAC states that to qualify, a utility must certify that it has expended an amount for conservation that is at least as great as the amount of the billing credit and describe the programs in which it has made the expenditures. *Id*. APAC claims all that BPA is obtaining from the utility is the promise to expend a certain amount, and BPA then imputes to that expenditure an amount of deemed savings based on the programs utilized. *Id*. APAC asserts that for the CRC program to qualify as a resource, BPA must be acquiring actual savings from the utility. *Id*.

However, APAC continues to ignore the requirements and procedures of the CRC program that are outlined in the General Rate Schedule Provisions, which require that participants adhere to the requirements of the CRC Implementation Manual. *See* Doubleday *et al*., WP-10-E-BPA-39, at 11-13. The CRC Implementation Manual procedures require that customers submit reports to the PTR system documenting qualifying CRC expenditures. GRSPs, Appendix B to this ROD, WP-10-A-01, Section II.A.3. The PTR system information, after being reviewed as discussed below, is transferred to BPA's Energy Efficiency Data Base (EEDB), which forms the basis of the information contained in the RED Book. The RED Book serves as the starting point for determining the amount of conservation savings included in the section 7(b)(2)(D) resource stack. A more detailed description of the Implementation Manual Procedures and BPA's internal review procedures establishes that actual savings are being acquired through the CRC program.

The amount of conservation savings associated with a conservation measure is determined through two separate methods. The first method is through "deemed savings." The Northwest Power and Conservation Council's Regional Technical Forum (RTF) on conservation is comprised of experts from regional utilities, consultants, and Northwest Power and Conservation Council staff. The RTF has established a list of conservation measures (deemed measure database) and the related savings associated with such measures. The deemed savings amount associated with the measures on the list are established through evaluations, measurements, and studies that provide assurance of the amount saved for the measure installed. The second method used to quantify conservation savings is through engineering reviews associated with "custom projects," which have measurement and verification plans specifically designed for the conservation measure being installed. The conservation savings associated with all BPA-sponsored conservation programs (including CRC) are input into the PTR system. The PTR information is transferred into the EEDB, which is used to quantify the information contained in the RED Book. Utilities report the number and type of conservation measures that were acquired under the CRC program, acquisition contracts, or other mechanisms into the PTR, while NEEA reports on the number and type of market transformation savings directly to BPA. The NEEA-reported savings are entered by BPA personnel into the EEDB. The information entered into the PTR is reviewed by a BPA Contracting Officer Technical Representative (COTR) for reasonableness and consistency. COTRs perform periodic site visits to the utility where underlying supporting documentation (invoices, inspection reports, and engineering review reports) are reviewed to verify the accuracy of the information input into the PTR by utility personnel. The information contained in the PTR and EEDB receives additional reviews to ensure consistency and completeness of the savings information. For each rate period, the COUs' aggregate qualifying expenditures reported in the PTR must equal or exceed the amount of provisional CRC credits granted. In instances where COTR reviews indicate that the amount of CRC expenditures are less than the amount of provisional CRC credits granted for the rate period, the PTR system informs the utility of the amount of additional expenditures required to zero out the balance owed or to reimburse BPA for the excess of provisional credits over expenditures.

In summary, all historical conservation savings from all conservation programs are determined "after the fact" following the procedures outlined above. The practice of quantifying the savings through the PTR system, which savings are reviewed by COTRs and subject to additional reviews and procedures in formulating the information contained in the EEDB, provides a rigorous and objective accounting of conservation savings. Projected conservation savings contained in the section 7(b)(2)(D) resource stack and scheduled to be acquired during the rate test period are based on projected conservation budget levels and the related cost per megawatthour associated with those budget projections. APAC's claim that it is necessary to project the level of conservation savings to be achieved for a given level of rate credits would create additional efforts with no material benefit. The projected savings amounts would need to be revised for the actual results to establish the actual amount of conservation savings reported in the EEDB and the RED Book.

Finally, in criticizing BPA's inclusion of CRC savings in the section 7(b)(2)(D) resource stack, APAC claims that the Northwest Power Act requires BPA to determine the amount of the resource it is acquiring before provisional CRC credits are granted (credits are provisional subject to COTR approval). APAC Br. Ex., WP-10-R-AP-01, at 5-6. APAC's argument is founded on a false assumption that ignores the CRC Implementation Manual Procedures that COUs are required to follow, along with the additional reviews and procedures that BPA has in place to ensure the measurement and accuracy of conservation savings. Under the CRC program, BPA objectively determines the amount of conservation it acquires, as noted in the procedures described above.

Decision

The adjusted conservation savings in service territories of BPA's preference customers resulting from market transformation expenditures and BPA's Conservation Rate Credit programs pertaining to loads that can be reduced by such conservation efforts are properly included in 7(b)(2) Case load augmentation and in the section 7(b)(2)(D) resource stack. The adjusted conservation savings in service territories of BPA's preference customers resulting from market transformation expenditures and BPA's Conservation Rate Credit programs pertaining to loads that cannot be reduced by these conservation efforts are properly excluded from 7(b)(2) Case load augmentation and from the section 7(b)(2)(D) resource stack.

10.3 Conservation Expensed Cost – Deferral and Financing Treatments, Decision Criteria

Issue 1

What is the proper treatment in the 7(b)(2) Case for conservation that is expensed in the Program Case?

Parties' Positions

The IOUs argue that expensed conservation should be recovered in the year it is incurred. IOU Br., WP-10-B-JP1-01, at 11. The IOUs claim that, in any event, expensed conservation should not be assumed to be amortized and financed over a period as long as five years, as BPA proposes. *Id*. The IOUs also claim it is standard practice in the industry to recover such expenses in the year they are incurred—"just like the Program Case treatment." *Id., citing* Doubleday, *et al*., WP-10-E-BPA-15, at 21. The IOUs argue that shortening the financing and amortization period in the 7(b)(2) Case for expensed conservation would be more consistent with the Initial Proposal's decision criteria. IOU Br., WP-10-B-JP1-01, at 14-15.

Cowlitz argues that BPA should never expense in the 7(b)(2) Case multiple years of "first year" conservation expenses in a single year. Cowlitz Br., WP-10-B-CO-01, at 15.

PPC *et al*. argue that BPA should spread the full costs of conservation over 15 years in the 7(b)(2) Case because that is the useful life of the resource. PPC *et al*. Br., WP-10-B-JP11-01, at 19.

BPA Staff's Position

BPA Staff proposes to finance and amortize expensed conservation over 5 years in the 7(b)(2) Case. Doubleday *et al*., WP-10-E-BPA-15, at 19.

Evaluation of Positions

BPA will continue to treat conservation as an available resource for purposes of the section 7(b)(2) rate test. Doubleday *et al*., WP-10-E-BPA-15, at 18. The cost and conservation savings amounts are updated to reflect BPA's projected conservation budgets for FY 2009-2015 and for changes in load assumptions used to calculate the amount and cost of conservation available for selection in the section 7(b)(2)(D) resource stack. *Id*. The amount and cost of annual conservation resources for FY 2001-2008 in the section 7(b)(2)(D) resource stack were revised to agree with the FY 2009 RED Book (scheduled to be published in July 2009) and adjusted for general and administrative costs as outlined in Appendix D to the 7(b)(2) Study Documentation – WP-10-FS-BPA-06A. Therefore, the cost of historical conservation resources for FY 2001-2008 is revised to include general and administrative overhead costs in the section 7(b)(2)(D) resource stack. In addition, the amount of capitalized conservation costs in the RED Book is adjusted to agree with BPA's financial records for FY2001-2008. The projected conservation savings amounts (aMW) and costs for FY 2009-2015 also are updated for changes to projected conservation budgets for FY 2009-2015 made during the IPR-2 process, which was conducted in spring 2009. *Id*. Conservation resources that have become obsolete by the end of the rate test period are removed from the section 7(b)(2)(D) resource stack. *Id*. Beyond these updates, no methodological changes are made to the treatment of conservation in performing the rate test. *Id*.

No other changes are made to the WP-07 Supplemental Final Proposal's treatment of conservation to address the obsolescence of conservation measures. *Id*. The life of conservation resources in the Initial Proposal is the same period of 15 years that was previously used in the WP-07 Supplemental Final Proposal. *Id*. The determination of which years of programmatic conservation are available to the section 7(b)(2)(D) resource stack is based on the same methodology. *Id*. For purposes of ratemaking, a programmatic conservation resource is assumed to be obsolete if its year of origin plus its expected life minus one totals less than the last year of the rate test period in question, FY 2015. *Id*. Conservation resources from FY 1982 to FY 2000 have been determined to be obsolete and have been removed from consideration in the calculation of base rates for the FY 2010-2015 rate test period. *Id*. at 19

BPA will change the accounting and financing treatment of expensed conservation costs in the 7(b)(2) Case. *Id*. BPA will defer, amortize, and finance the annual expensed amounts of conservation expenditures over a 5-year period. *Id*. In the WP-07 Supplemental ROD, a 7-year period was used to defer, amortize, and finance the annual expensed amounts of conservation. *Id.*, *citing* WP-07 Supplemental ROD, WP-07-A-05, at 471-509.

In the WP-07 Supplemental ROD, BPA established criteria to help determine what the Joint Operating Agency (JOA) would have likely done in the 7(b)(2) Case in choosing the accounting and financing policies associated with making a large conservation investment. Doubleday *et al.*, WP-10-E-BPA-15, at 19. The WP-07 Supplemental ROD criteria were 1) Resource Stack Composition; 2) Additional Financing Costs Associated with Deferring the First-Year Expensed Costs; 3) Number of Years Required to Recover Conservation Costs; and 4) the Cost Treatment Comparability Between the Program Case and the 7(b)(2) Case. *Id.* In the Initial Proposal, Staff proposes to add a fifth criterion, 7(b)(2) Case Rate Impacts, in arriving at its conclusion to amortize and finance the deferred expensed conservation expenditures over a 5-year period. *Id.*

The proposed 7(b)(2) Case Rate Impact criteria are used to evaluate the impact of the different conservation expense financing time periods in the 7(b)(2) Case rate. *Id.* The purpose of the evaluation criteria is *not* to decide what the appropriate 7(b)(2) Case rate should be. *Id.* at 19-20. The purpose of the analysis is to quantify the amount of the first year rate "spike" associated with an alternative of expensing in the year incurred and to evaluate the positive and negative attributes of the different deferral alternatives in arriving at an accounting and financing policy that would best serve the JOA and its 7(b)(2) member utilities. *Id.* at 20.

The five criteria help determine the appropriate accounting and financing treatment used in the 7(b)(2) Case. *Id.* The first criterion, section 7(b)(2)(D) resource stack composition, was chosen for its ability to identify the number of resources, their quantity, and their related costs that were used to meet 7(b)(2) Customer loads. *Id.* This criterion establishes the degree to which conservation resources are relied upon to meet 7(b)(2) Case loads and to help justify the deferral treatment for conservation expenses. *Id.* The fifth criterion, 7(b)(2) rate impacts, quantifies the amount of the first year rate "spike" associated with the alternative to expense all conservation expense costs in the year incurred, and to evaluate the rate reduction benefits associated with the deferral alternatives. *Id.* The other three alternatives (two, three, and four) are used for their ability to quantify the amount of additional interest expense, the additional time required to recover conservation costs, and the overall comparability of the amount of conservation expenses contained in the Program Case and the 7(b)(2) Case. *Id.* These three criteria, taken together, assist in the quantification of the additional costs and the additional time required to recover expensed costs in rates associated with the deferral of the first-year conservation operating expenses. *Id.* All of the criteria taken together assist in evaluating the costs and benefits of the different alternatives in reaching a decision on the appropriate deferral period that would best serve the JOA and its member utilities. *Id.*

BPA treats capitalized conservation costs in the same manner across all of the alternatives; they were financed over a period of 15 years. *Id.* at 21. Several different amortization/financing periods are considered and analyzed for conservation expenditures that are operating expenses of the period (first year expenses) in the Program Case:

> Alternative 1 –Expense the operating expenses in the year incurred, just like the Program Case treatment.

Alternative 2 – Defer the operating expenses and finance them over 4 years.

Alternative 3 – Defer the operating expenses and finance them over 5 years.

Alternative 4 – Defer the operating expenses and finance them over 6 years.

Alternative 5 – Defer the operating expenses and finance them over 7 years.

Alternative 6 – Defer the operating expenses and finance them over 15 years.

These alternatives cover the minimum (Alternative 1) and the maximum (Alternative 6) limits of expense deferment, along with the most probable range of alternatives to be considered for analysis. *Id*.

Key conclusions from Staff's analysis of the five factors that support this decision are the following:

(1) *Section 7(b)(2)(D) Resource Stack Resources Chosen to Meet 7(b)(2) Customer Load–Resource Stack Composition:* Nine out of twelve resources chosen to meet 7(b)(2) Customer loads in the first year are conservation resources (255 aMW), comprising 73 percent of the energy needed to meet 7(b)(2) loads in the first year. The size of the first year conservation program, together with the cumulative amount of first year expensed costs of $325 million and the "spike" in the rate for FY 2010, support a decision to defer these expenditures under Statement on Financial Accounting Standards No. 71 – Accounting for the Effects on Certain Types of Regulation, as compared to recovering all expensed costs in the year they were incurred.

(2) *Financing Cost Impacts:* The additional financing costs associated with deferring the recovery of expensed conservation costs can significantly increase the cost of conservation when a longer deferral period is chosen. The choice of a 15-year deferral and financing period would increase the cost of conservation by $312.4 million (nominal dollars), an amount that is a 40.34 percent increase above the original expensed conservation costs. Deferring and financing conservation costs over four to seven years increases the cost of conservation from $72.9-127.7 million, which amounts to a 9.42-16.50 percent increase above the original expensed conservation costs. The amount of additional interest expense and the cumulative rate impacts of deferring these costs into later rate periods support the choice of a shorter deferral period.

(3) *Cost Recovery:* The cost recovery analysis demonstrates that Alternative 1, with no deferral of first year conservation expenses, recovers 73.8 percent of the total costs of conservation (excluding interest) within the rate test period. Alternative 6, which defers and finances the operating expenses over 15 years, recovers only 22.3 percent of the total costs over the rate test period. Alternatives 2 through 5 recover a range of 61.5 percent to 46.0 percent of the total conservation costs over the rate test period. Alternatives 2 and 3 were the best choices to mitigate the delay in recovering expensed costs so that they could be reinvested in additional utility plant assets or redeployed to meet the other operating needs of the utility.

(4) *Comparability of Costs:* The comparability analysis compares the conservation cost treatment between the Program Case and the 7(b)(2) Case. The Program Case revenue

requirement includes: 1) conservation expenses, all are expensed in the first year they are incurred; 2) the amortization expense associated with twenty-one years of prior capitalized conservation costs; and 3) the interest expense component of debt service. In contrast, the 7(b)(2) Case revenue requirement includes the debt service (both principal and interest) associated with the deferral of operating expenses along with the debt service (both principal and interest) of capitalized expenditures that are amortized and financed over a 15-year period. Both Cases have the same level of Planned Net Revenues for Risk (PNRR) and a level of Minimum Required Net Revenues (MRNR) associated with the separate repayment studies for each Case. Although the accounting and financing treatments are different between the two Cases, there is concern that the choice of a longer expense deferral period increases the difference in the revenue requirements amounts between the two Cases, which can have an impact on the rate test. The 6-year "restated" average annual comparable conservation cost in the Program Case revenue requirement is $155.1 million. The 6-year average annual conservation cost amount in the 7(b)(2) Case is $136.0 million with the choice of Alternative 3, deferral over 5 years (Study, WP-10-E-BPA-06, Appendix B, Summary Analysis – Accounting /Financing Treatment of Expensed Conservation Costs, B-10). The average annual Program Case costs $19.1 million more than the 7(b)(2) Case (Program Case costs are 14 percent greater than 7(b)(2) Case costs).

(5) *7(b)(2) Rate Analysis:* The rate impact analysis results demonstrate that without a decision to defer the first-year conservation costs, there is a spike in rates in the first year. In addition, the rate analysis results demonstrate that a deferral policy of 4 to 7 years would provide rate savings of $1.55/MWh to $2.13/MWh compared to an accounting treatment of expensing the conservation expenditures in the year they were incurred. The rate analysis showed that a 15-year deferral period would provide rate savings of $2.52/MWh compared to the expense treatment. The incremental rate savings of $0.98/MW to $0.39/MWh associated with the 15-year alternative over Alternatives 2 through 5 are outweighed by the increased financing costs, longer cost recovery time, and the lack of cost comparability associated with this alternative and the Program Case.

After analyzing all five decision criteria outlined above (Study, WP-10-E-BPA-06, Appendix B, Summary Analysis – Accounting /Financing Treatment of Expensed Conservation Costs, B-6 through B-11), BPA finds that the five-year amortization and financing period (Alternative 3) is the best choice. In making this finding, all five criteria are considered without weighting or ranking. The decision to change the amortization period of expensed costs to five years in the current case versus the 7 years used in the WP-07 Supplemental Case is based on the following considerations: 1) amortizing the expensed costs over five years (Alternative 3) is proposed because it reduces the cost (interest expense) of undertaking conservation in the 7(b)(2) Case by $37.5 million compared to the 7-year (Alternative 5) deferral period, *id*. at 24; and 2) the 5-year deferral period also shortens the recovery period by approximately 1.5 years (weighted average recovery period) compared to the 7-year deferral period. *Id*.

In conclusion, the choice of a 5-year deferral and amortization period achieves the best balance between mitigating the rate impacts associated with multiple vintage conservation programs being selected and the negative consequences associated with deferring the first-year operating expenses. *Id*.

A. IOU Arguments

The IOUs note the Initial Proposal proposes five decision criteria to help determine what the JOA (the entity assumed to be established by the 7(b)(2) Customers to finance conservation acquisition in the 7(b)(2) Case) would likely have done in choosing the accounting and financial policies associated with making a large conservation investment. IOU Br., WP-10-B-JP1-01, at 10. The Initial Proposal proposes to finance and amortize expensed conservation over a five-year period in the 7(b)(2) Case. *Id.*, *citing* Doubleday *et al.*, WP-10-E-BPA-15, at 20.

The IOUs argue that expensed conservation should be recovered in the year it is incurred. IOU Br., WP-10-B-JP1-01, at 11. They state that, in any event, expensed conservation should not be assumed to be financed and amortized over a period as long as five years, as Staff proposes. *Id.* The IOUs claim it is standard practice in the industry to recover such expenses in the year they are incurred—"just like the Program Case treatment." *Id.*, *citing* Doubleday, *et al.*, WP-10-E-BPA-15, at 21. The IOUs state that prior to the WP-07 Supplemental ROD, BPA recovered expensed conservation in the year it was incurred not only in the Program Case but also in the 7(b)(2) Case. IOU Br., WP-10-B-JP1-01, at 11. The IOUs state that Staff continues to properly follow the practice of recovering expensed conservation in the Program Case in the year that it is incurred. *Id.* at 11-12, *citing* Doubleday *et al.*, WP-10-E-BPA-15, at 21. They claim there is no basis for using a different number of years for recovery of expensed conservation in the 7(b)(2) Case. IOU Br., WP-10-B-JP1-01, at 12.

The IOUs state that using a five-year financing and amortizing period for expensed conservation in the 7(b)(2) Case (rather than recovering it in the year incurred, as in the Program Case) results in conservation debt service in the 7(b)(2) Case that is about $19 million in total lower over the six-year period than conservation debt service in the Program Case. *Id.* They claim this inappropriately and unnecessarily biases the result of the section 7(b)(2) rate test, causing the section 7(b)(3) trigger to be $19 million higher than it would be if this error were corrected. *Id.* In contrast, the IOUs state that recovering expensed conservation in the 7(b)(2) Case in the year it is incurred results in conservation debt service that is nearly identical in the Program Case and the 7(b)(2) Case, *citing* Staff's Cost Comparability analysis in Appendix B to the Study, WP-10-E-BPA-06:

(i) In the 7(b)(2) Case, the average annual debt service for FY 2010-16 is $155,228,200 if expensed conservation is recovered in the year that it is incurred.

(ii) In the Program Case, the average annual debt service for conservation in FY 2010-16 is $155,060,800.

BPA does not agree with the IOUs' characterization of the Cost Comparability Criterion – Factor 4 in the Study, WP-10-E-BPA-06, at B-10. Doubleday *et al.*, WP-10-E-BPA-39, at 27. (Note: All of the evaluation criteria analysis results quoted are based on the Initial Proposal's Appendix B to the Study, WP-10-E-BPA-06. Appendices A, B, C, and D are revised for the final studies. The decision to defer and finance the expensed conservation costs over five years is not changed as a result of the updating for the final study results.) BPA agrees with the quoted difference of $19 million in average annual conservation costs between the Program Case and 7(b)(2) Case, and that the amounts cited by the IOUs are correct. *Id.* However, BPA does not agree with the IOUs' conclusion that Alternative 1 (Expensing Costs in the Year Incurred) should be chosen because the 6-year average conservation costs are more alike, when compared to the Program Case, than Alternative 3's treatment of deferring and financing the expensed conservation costs over 5 years. *Id*. The IOUs' conclusion that the $19 million average annual difference in conservation debt service between Alternative 1 and Alternative 3 for the 7(b)(2) Case results in the Trigger Amount being $19 million higher is incorrect. *Id*. There is a much larger set of costs that make up the total revenue requirement for each year of the rate test period for each respective case that explains the difference in costs between the two Cases.

Concerning the comparability of the average annual conservation cost amounts, BPA has consistently stated that the populations of conservation cost amounts between the Program Case and the 7(b)(2) Case are not comparable. *Id*. at 28 The creation of the section 7(b)(2)(D) resource stack and the accounting and financing policies governing the resources in the section 7(b)(2)(D) resource stack is due to the operation of one of the five assumptions, namely section 7(b)(2)(D) of the Northwest Power Act. *Id*. The amounts of the Federal base system resources, along with other resources used to serve the loads in each respective Case, are different and not comparable. *Id*. The creation of the section 7(b)(2)(D) resource stack and the selection of resources from the stack in least-cost order results in a different population of conservation costs being recovered in the 7(b)(2) Case. *Id*. One should expect a difference in the annual conservation cost amounts between the two Cases. *Id*. The table on page B-10 of the Documentation, WP-10-FS-BPA-06A, presents a comparison of similar categories of costs between the Program Case and the 7(b)(2) Case. *Id*. The amount of conservation costs between the two Cases should not be equal. *Id*. Staff's table is useful for rate case parties to know the difference in the composition of conservation costs between the two Cases in addition to the difference in total conservation costs between the two Cases.

The $19 million average annual difference in conservation costs will change dramatically over time due to the different accounting treatments governing conservation resources in the two Cases. *Id*. The Program Case conservation cost for FY 2010 contains the amortization expense of 21 vintage years of historical conservation capitalized costs:

- Conservation Amortization – 20-year lives, (12) vintage years FY 1990-2001;
- ConAug Conservation Amortization – declining year method, (6) vintage years FY 2002-2007; and
- Conservation Amortization – 5-year lives, (3) vintage years FY 2008-2010.

Id. Thus, the Program Case for FY 2010 contains the amortization of *21 years* of capitalized conservation investments totaling $50.3 million. *Id*., *citing* Study, WP-10-E-BPA-06, at B-10, lines 28-29. By FY 2021, all of the cost recovery associated with conservation that was amortized over 20 years will have occurred, and all of the cost recovery of ConAug Conservation will have been completed by the end of FY 2011. Doubleday *et al*., WP-10-E-BPA-39, at 29. Only the amortization expense associated with *5 years* of capitalized conservation costs (FY 2016-2021) being amortized over five years will be present in the FY 2021 Program Case conservation costs. *Id*. The FY 2010 Program Case also contains interest expense of $13.8 million associated with FY 1998-2010 conservation bonds and third-party financed conservation bond debt service of $5.1 million. *Id*., *citing* Study, WP-10-E-BPA-06, at B-10, lines 30 and 31. In addition to these costs associated with prior years' conservation efforts, the FY 2010 Program Case contains the expensed costs associated with the FY 2010 conservation program totaling $86.9 million. *Id.*, *citing* Study, WP-10-E-BPA-06, at B-10, line 25.

In comparison, the 7(b)(2) Case revenue requirement for FY 2010 contains the debt service associated with *9 years* of vintage conservation investments relating to the years FY 2001-2009, whose capitalized costs are financed over a 15-year period, and the expensed costs that are being deferred and financed over a 5-year period totaling $88.1 million. Doubleday *et al*., WP-10-E-BPA-39, at 29, *citing* Study, WP-10-E-BPA-06, at B-10, line 49. One can readily see that the population of costs between the Cases is very different. Doubleday *et al*., WP-10-E-BPA-39, at 29. In addition, the shape of the annual amounts of conservation costs is different between the two Cases. *Id*. The "Similar Program Case Comparison" on line 42 of page B-10 has a fairly even annual cost stream during the rate test period (FY 2010-2015) of $160.4 million to $149.2 million dollars. *Id*. Alternative 3 for the 7(b)(2) Case (5-year deferral/financing of expensed conservation costs on line 49 of page B-10) presents a rapidly increasing annual stream of costs ranging from $88.1 million in FY 2010 to $185.0 million in FY 2014 before decreasing to $137.2 million in FY 2015. *Id*. The cost stream associated with Alternative 1 "front-loads" the conservation costs. *Id*. Alternative 1's expensing of costs in the year incurred (the position advocated by the IOUs) would have presented the following debt service amounts (capitalized and expensed costs in millions): FY 2010, $340.5; FY 2011, $104.4; FY 2012, $111.3; FY 2013, $118.6; FY 2014, $126.1; and FY 2015, $130.4. *Id*. at 29-30.

In summary, the IOUs' argument that Alternative 3 biases the rate test result is based on a false premise. *Id*. at 30. The IOUs assume that the level of conservation costs should be the same in the two cases, when in fact they should be different, because there are a different number of years of conservation costs present in the two Cases, and the amount of conservation costs and savings for each year is different. *Id*. The two Cases are meant to be different due to the operation of sections 7(b)(2)(D) and 7(b)(2)(E) of the Northwest Power Act. *Id*. In addition, for clarification purposes, the $19 million difference (which the IOUs assert gives rise to a bias in the rate test result) is not primarily due to the choice of Alternative 3 versus Alternative 1. *Id*. As pointed out above, the difference arises because 21 years of conservation cost recovery present in FY 2010 in the Program Case, while only 9 years of conservation cost recovery is taking place in the 7(b)(2) Case. *Id*. Thus, BPA disagrees with the IOUs' conclusion that the choice of the five-year deferral period (Alternative 3) biases the rate test result. *Id*.

The IOUs state that under Criterion 1 (Resource Stack Composition), BPA states that 73 percent of the aMWs of first-year resources selected from the section 7(b)(2)(D) resource stack are conservation resources. IOU Br., WP-10-B-JP1-01, at 12. The IOUs allege the Initial Proposal fails to explain why this fact argues for any particular financing and amortizing method. *Id*. The IOUs state that under Criterion 2 (Financing Cost Impacts), financing and amortizing over five years as opposed to a one-year recovery increases the interest paid by $90 million. The Initial Proposal recognizes the following:

> The amount of additional interest expense and the cumulative rate impacts of deferring these costs into later rate periods support the choice of a shorter deferral period.

Id. at 13, *citing* Doubleday *et al*., WP-10-E-BPA-15, at 22. The IOUs note that under Criterion 3 (Cost Recovery), Staff states that 73.79 percent of the total costs are recovered in the rate step period under Alternative 1 (No Deferral), versus 57.43 percent for Alternative 3 (Financing Over 5-Years). IOU Br., WP-10-B-JP1-01, at 13. Thus, the IOUs argue Alternative 1 (No Deferral) was the best choice "to mitigate the delay in recovering expensed costs so that they could be reinvested in additional utility plant assets or redeployed to meet the other operating needs of the utility." *Id*., *citing* Doubleday *et al*., WP-10-E-BPA-15, at 22.

The IOUs state that Criterion 4 (Comparability of Costs) is also best met by Alternative 1 (No Deferral), because the costs in the Program and 7(b)(2) Cases are nearly the same under that alternative. IOU Br., WP-10-B-JP1-01, at 13. The Initial Proposal states that Criterion 5 (7(b)(2) Rate Impacts) supports the use of financing and amortization over five years because of a rate "spike" in FY 2010. *Id., citing* Doubleday *et al*., WP-10-E-BPA-15, at 24. However, the IOUs state Staff's focus on section 7(b)(2) rate impacts in FY 2010 is misplaced. IOU Br., WP-10-B-JP1-01, at 13.

Thus, the IOUs conclude that the analyses under Criteria 2, 3, and 4 favor Alternative 1. *Id*. They claim Criteria 1 and 5 should be considered as relatively neutral (or should be given little weight) as between Alternatives 1 and 3, given that the analyses under Criteria 1 and 5 do not clearly favor the selection of one alternative over the other. *Id*. at 13-14.

The IOUs have mischaracterized Staff's analysis of the five criteria. Doubleday *et al*., WP-10-E-BPA-39, at 31. A more detailed description of Staff's analysis of the five criteria is presented below.

Criterion 1 – 7(b)(2) Selected Resource Composition (Study, WP-10-E-BPA-06, at B-6 and B-7). This criterion identified the number of resources, their quantity, and the composition of the resource costs:

> Nine out of twelve resources chosen to meet 7(b)(2) Customer loads in the first year are conservation resources (255 aMW), comprising 73 percent of the aMW needed to meet 7(b)(2) loads in the first year. The size of the first year conservation program, together with the amount of first year expensed costs of $325 million and the 'spike' in the rate for FY 2010, support a decision to defer these expenditures under Statement on Financial Accounting Standards No. 71 – Accounting for the Effects on Certain Types of Regulation, as compared to choosing to expense them in the first year.

Doubleday *et al*., WP-10-E-BPA-39, at 31, *citing* Doubleday *et al*., WP-10-E-BPA-15, at 21-22.

Criterion 5 – 7(b)(2) Rate Analysis (Study, WP-10-E-BPA-06, at B-11). In support of the analysis of the five criteria, Staff testified:

> The rate impact analysis results demonstrate that without a decision to defer the first-year conservation costs, there is a spike in rates in the first year. In addition, the rate analysis results demonstrate that a deferral policy of 4 to 7 years would provide rate savings of $1.55/MWh to $2.13/MWh compared to an accounting

treatment of expensing the conservation expenditures in the year they were incurred.

Doubleday *et al.*, WP-10-E-BPA-39, at 31, *citing* Doubleday *et al.*, WP-10-E-BPA-15, at 24. The first criterion established the amount of expensed conservation costs that would be expensed in the first year of the rate test period ($325.1 million) if the decision to defer these costs was not made, and the fifth criterion quantified the amount of the rate spike associated with the 7(b)(2) Case rates if Alternative 1 (expense in the year incurred) was chosen. Doubleday *et al.*, WP-10-E-BPA-39, at 31. In contrast to the IOUs' conclusion that Criteria 1 and 5 should be considered as neutral factors that should be given little or no weight, Staff determined that these two criteria taken together established the basis for the JOA to decide to defer and finance the expensed conservation costs and to reject the choice of Alternative 1. *Id.* These two criteria establish that Alternative 1 should not be adopted given the large amount of "first year" expensed costs and the related spike in rates that would occur if Alternative 1 were selected. *Id.*

Criterion 2 – Financing Cost Impacts (Study, WP-10-E-BPA-06, at B-8). This analysis quantifies the amount of additional interest expense that is associated with the alternative deferral periods. *Id.* at 32. The analysis indicates there is a relatively tight band of financing costs associated with the alternatives to defer the expensed costs over 4 to 7 years of $72.9 million to $127.7 million in nominal dollars over the FY 2010-2021 period. *Id.* The financing cost analysis indicates that the additional interest expense associated with the 4- to 7-year deferral periods amounts to only 9.42 percent to 16.5 percent of the original historical expensed costs. *Id.* The cost of avoiding the rate spike and lowering rates during the FY 2010-2011 rate period by a range of $1.55/MWh to $2.13/MWh for Alternatives 2-5 (quantified by Criterion 5 on page B-11) for all 7(b)(2) Customer loads during this time period would be equal to the $72.9 to $127.7 million (nominal dollars) in additional interest expense spread over the FY 2010 to FY 2021 time period. *Id.* Subsequent rate periods would continue to see a decrease in rates as a result of the FY 2010 deferral decision. *Id.* The rate of decrease would diminish over subsequent years. There would be an additional cost associated with the deferral of the principal in terms of the additional borrowings that would be incurred to be able to undertake additional utility investments of the JOA and its member utilities stemming from the deferral of the return of principal. *Id.* This cost associated with the delay in replenishing reserves/working capital is not quantified in the analysis. *Id.*

The additional interest expense associated with deferring the expensed costs over a 15-year period associated with Alternative 6 amounts to $312.4 million (nominal dollars) in additional costs over the FY 2010-2029 time period. *Id.* at 32-33. The rate analysis shows that a 15-year deferral period would provide rate savings of $2.52/MWh compared to the expense treatment (Alternative 1). *Id.* at 33. The incremental rate savings of $0.98/MW to $0.39/MWh associated with the 15-year deferral period in Alternative 6 over the 4- to 7-year deferral treatments contained in Alternatives 2 through 5 are outweighed by the increased financing costs that raised the amount of historically expensed costs by an additional 40.34 percent. *Id.* In addition, Alternative 6 substantially increases the length of time over which expensed costs would be recovered. *Id.* The JOA and its member utilities would not choose a deferral period of 15 years to recover costs that are normally expensed in the year incurred. *Id.* The JOA and its member consumer-owned utilities, in adopting a balanced approach of deferring the large cumulative amount of first-year expensed costs to mitigate the resulting rate shock, would choose to recover the expensed costs over a relatively short period of years based on the following considerations:

- The JOA and its members would want to operate in a manner that is consistent with sound business principles.
- They would be cognizant of matching the current costs of operations with current rates. Although the JOA and the member utilities would be able to capitalize and defer conservation expenditures, sound business practices and prudent utility practices would temper the amount of deferred regulatory assets.
- They would maintain high credit ratings, so the cost of financing their operations would be low and they would have good access to credit markets.
- They would maintain adequate financial reserves for operations and to meet or exceed debt coverage ratio requirements associated with bond covenants and operating lines of credit.

Id. at 33. At the conclusion of this first phase of the analysis, BPA concludes that the JOA decisionmakers would eliminate Alternatives 1 and 6 from consideration for the reasons discussed above. *Id*. at 34.

During the second phase of the analysis, the choice between deferring and financing the expensed costs over 4 to 7 years is based on the desire to capture a substantial amount of the rate benefits (decreased 7(b)(2) Customer rates) quantified by Criterion 5 while at the same time mitigating the additional interest expense (Criterion 2) and decreasing the recovery time (Criterion 3) associated with the expensed costs. *Id*. As explained above in the discussion of Criterion 2 - Financing Costs Associated with the Different Deferral Periods (page B-8), there is a relatively tight range of additional interest expense associated with Alternatives 2-5. *Id*. "The amount of additional interest expense and the cumulative rate impacts of deferring these costs into later rate periods support the choice of a shorter deferral period." *Id., citing* Doubleday *et al.*, WP-10-E-BPA-15, at 22.

Criterion 3 – Cost Recovery (Study, WP-10-E-BPA-06, at B-9). Two separate metrics were developed to gauge the level of cost recovery. Doubleday *et al*., WP-10-E-BPA-39, at 34. The first metric, which Staff discussed in testimony, quantifies the percentage of total historical conservation costs that are recovered by the end of the 6-year rate test period. *Id*. Alternatives 2, 3, and 4, which defer the expensed cost over 4 to 6 years, all recover more than 50 percent of the total conservation costs (stated in nominal dollars) used to serve 7(b)(2) Case loads during the rate test period. Alternative 5, which defers the expensed costs over 7 years, recovers 46.03 percent of the total conservation costs by the end of the rate test period. *Id*. The second metric presented in the cost recovery analysis quantifies the weighted average recovery period associated with the capitalized costs being recovered over 15 years in all Alternatives, with the expensed costs being recovered over the range of 4 to 7 years under Alternatives 2 through 5. *Id*. The weighted average recovery period ranges from 7.71 years for Alternative 2 (Deferral of expensed costs over 4 years) to 9.70 years for Alternative 5 (Deferral of expensed costs over 7 years). *Id*. at 34-35. "Alternatives 2 and 3 were the best choices to mitigate the delay in recovering expensed costs so that they could be reinvested in additional utility plant asset or redeployed to meet other operating needs of the utility." *Id*. at 35, *citing* Doubleday *et al*., WP-10-E-BPA-15, at 22-23.

Criterion 4 – Cost Comparability (Study, WP-10-E-BPA-06, at B-10). This criterion serves as a useful frame of reference or benchmark to test the overall reasonableness of the cost of conservation in the 7(b)(2) Case. Doubleday *et al*., WP-10-E-BPA-39, at 35. The analysis at page B-10 provides an understanding of the differences in the population of conservation costs that are present in the two cases and helps gauge the reasonableness of the decision concerning the number of years over which to defer and finance expensed conservation costs. *Id*. As noted above, the principal reason the JOA and its member utilities would not choose Alternative 1 (Expense the expensed costs in the year incurred) is due to the significant spike in first-year rates that would result from that choice. *Id*. In addition, the JOA and its member utilities would not choose Alternative 6 (Deferring and Financing the Expensed Costs over Fifteen Years) because the additional amount of interest expense and the long recovery period for costs that are normally expensed in the year incurred would not be a prudent or sound business decision. *Id*.

Although Criterion 4, Cost Comparability between the two Cases, would be exogenous to the reality of the JOA decision makers, Staff is sensitive to the fact the selection of a longer time period to defer and amortize conservation lowers the 7(b)(2) Case revenue requirement, which in turn increases the difference in treatment of conservation costs between the two Cases. The Cost Comparability Criterion reinforces the decisions made from the perspective of the JOA to reject Alternatives 1 and 6 in favor of Alternatives 2-5. *Id*. Alternatives 1 and 6, in addition to being inferior choices from the perspective of the JOA, would also decrease the comparability of conservation costs between the two Cases to a significant degree. *Id*. With regard to Alternative 6 on this point, Staff testified "Although the accounting and financing treatments are different between the two Cases, there is concern that the choice of a longer expense deferral period increases the difference in the revenue requirements between the two Cases." *Id*. at 35-36, *citing* Doubleday *et al*., WP-10-E-BPA-15, at 23. After analyzing the remaining Alternatives 2-5 against Criteria 2, 3, and 5, Staff determined that the 5-year amortization and financing period (Alternative 3) is the best choice. Doubleday *et al*., WP-10-E-BPA-39, at 36.

The IOUs also took issue with the importance that Staff placed in the significant increase in the 7(b)(2) rate for the first year of the rate test period, stating that the "Initial Proposal apparently expresses concern that the addition of significant amounts of conservation in the 7(b)(2) Case for FY 2010 causes a price "spike" in the 7(b)(2) Case costs." IOU Br., WP-10-B-JP1-01, at 15, *citing* Doubleday *et al.*, WP-10-E-BPA-15, at 24. They claim that focusing on the first year effect of recovering expensed conservation in FY 2010 is misplaced because BPA conducts the section 7(b)(2) rate test over six years (FY 2010-2015), which avoids any potential aberrations caused by FY 2010 costs. IOU Br., WP-10-B-JP1-01, at 15. The IOUs reiterate that it is inappropriate to depart in the 7(b)(2) Case from the treatment of expensed conservation in the Program Case—recovery in the year incurred. *Id*.

BPA disagrees with this argument. The JOA in the 7(b)(2) Case is still setting rates for the same 2-year period (FY 2010-2011) as the Program Case. Doubleday *et al*., WP-10-E-BPA-39, at 26. Alternative 1 - Expense in the Year Incurred produces a 2-year rate of $27.99/MWh compared to the 2-year rate of $26.17 under Alternative 3 - the 5-year Deferral. *Id*., *citing* Study, WP-10-E-

BPA-06, at B-11. There clearly is a large increase in the 2-year rate period rate that is correctly categorized as a "rate spike." Averaging the first year impact with the other five years of the rate test period does not avoid "any potential aberration" as the IOUs claim. Most utilities and utility commissions would seek to mitigate a rate spike if they had other rate and accounting tools at their disposal. For example, it is normal utility practice to defer significant storm damage expense over a number of years if immediate recovery would cause a rate spike. Again, the purpose of the analysis was to quantify the amount of the first year rate increase associated with "expensing in the year incurred" alternative and to evaluate the rate reduction benefits of the deferral alternatives using the other four criteria to arrive at an accounting and financing policy that would best serve the JOA and its 7(b)(2) Customer utilities. The IOUs' argument that the importance of the rate increase (rate spike) is misplaced and that somehow it should be given little weight or ignored lacks merit.

In conclusion, the IOUs' principal argument that the analyses under BPA's decision criteria taken as a whole and BPA's treatment of expensed conservation in the Program Case both support Alternative 1 (No Deferral) is not substantiated by the analysis explained above and as documented in Appendix B to the Study, WP-10-E-BPA-06.

The IOUs also offered an alternative argument, that if BPA does not adopt Alternative 1, the analyses under BPA's decision criteria taken as a whole and BPA's treatment of expensed conservation in the Program Case support the recovery of expensed conservation over a period of less than five years. IOU Br., WP-10-B-JP1-01, at 14-16. The IOUs state that BPA itself has recognized that the results of using a four-year deferral and financing period in the 7(b)(2) Case for expensed conservation are similar to using a five-year period, in terms of satisfying its criteria. *Id*., *citing* Doubleday *et al*., WP-10-E-BPA-39, at 37. The IOUs state that in light of this recognition and in light of the strong argument in favor of recovering expensed conservation in one year in the 7(b)(2) Case, that BPA should adopt a deferral and financing period in the 7(b)(2) Case for expensed conservation that is as short as feasible, but in any event no longer than four years. IOU Br., WP-10-B-JP1-01, at 16.

BPA agrees with this argument to a limited extent. Staff's proposal to choose a deferral and financing period of 5 years (Alternative 3) is objective and supported by the analysis. Doubleday *et al.*, WP-10-E-BPA-39, at 36. However, Alternative 2 (Deferring and financing the expensed costs over 4 years) is very similar to Alternative 3. *Id*. Its choice is also supported by the analysis. *Id*. The primary difference between the two alternatives is the slightly higher degree of additional 7(b)(2) Customer rate savings achieved by Alternative 3, albeit at a slightly higher amount of interest expense and a slightly longer recovery period. *Id*.

However, BPA does not agree that expensed conservation costs should be recovered in the 7(b)(2) Case in the year incurred, for the reasons stated previously. *Id*. at 37. Staff did not state that a deferral and financing period of 5 years was too long. *Id*. The five-year deferral and financing period is supported by the analysis using the five decision criteria proposed in the Initial Proposal. *Id*. As noted previously, the results of the analysis using the 4-year deferral and financing period is very similar to the analysis results for the 5-year deferral and financing period. *Id*.

B. Cowlitz Arguments

Cowlitz argues that assuming BPA's basic proposal to include conservation in the section 7(b)(2)(D) resource stack and to increase the 7(b)(2) Customers' general requirements has merit, BPA should never expense in the 7(b)(2) Case multiple years of "first year" conservation expenses in a single year. Cowlitz Br., WP-10-B-CO-01, at 15. Cowlitz states the percentage of conservation costs BPA expenses during the 7(b)(2) rate period is a significant factor affecting the cost of "conservation resources" that BPA includes in the 7(b)(2) Case. *Id*. Cowlitz asserts that BPA has traditionally "expensed" a large and increasing percentage of its conservation expenditures in the first year they are incurred. *Id*., *citing* Study, WP-10-E-BPA-06, at D-20. Cowlitz claims these "first year expenses" are salaries, overheads and other infrastructure costs necessary to maintain a conservation program. Cowlitz Br., WP-10-B-CO-01, at 15, *citing* Cross Ex. Tr. at 50-53. Cowlitz concludes that, as infrastructure costs, these costs are not highly correlated with the amount of conservation achieved. Cowlitz Br., WP-10-B-CO-01, at 15, *citing* Cross Ex. Tr. at 53.

Cowlitz states that in this case, nine of the twelve resources BPA selects to meet 7(b)(2) Customer Loads in FY 2010 in the 7(b)(2) Case are conservation resources. Cowlitz Br., WP-10-B-CO-01, at 16. The total of the "first year" conservation expenses for these nine resources is $325 million. *Id*., *citing* Doubleday *et al*., WP-10-E-BPA-15, at 21-22. BPA proposes to amortize this $325 million over five years in the 7(b)(2) Case. Cowlitz Br., WP-10-B-CO-01, at 16. The IOUs urge BPA to expense the entire $325 million in first year expenses for all nine conservation resources in the first year of the 7(b)(2) Case rate period. *Id*., *citing* LaBolle *et al*., WP-10-E-JP1-01, at 23-30. They claim such treatment is consistent with how BPA expenses conservation expenditures in the Program Case. Cowlitz Br., WP-10-B-CO-01, at 16, *citing* LaBolle *et al*., WP-10-E-JP1-01, at 29-30. Cowlitz argues that the IOUs are wrong. Cowlitz Br., WP-10-B-CO-01, at 16.

Cowlitz states that in the Program Case, BPA expenses only those "first year" conservation expenses that are actually incurred in each year. *Id*. As is shown in the Study, WP-10-E-BPA-06, at D-20, only one of the conservation resources BPA selects to include in the 7(b)(2) Case involves "first year" expenditures incurred by BPA in the first year of the rate period, that is, in FY 2010. *Id*. Moreover, for purposes of determining its revenue requirement, BPA has never expensed more than one "first year expense" of conservation per year. *Id*., *citing* Brodie, Cross Ex Tr. at 54. Cowlitz states there is no basis for BPA to pretend that "first year expenses" that have previously been recovered through rates should be included as future costs in the 7(b)(2) Case. Cowlitz Br., WP-10-B-CO-01, at 16. Cowlitz argues that in no event should BPA expense in FY 2010 or any other year, any conservation costs not actually incurred in that year. *Id*.

BPA does not agree with Cowlitz's position on expensed conservation costs in the 7(b)(2) Case. The expensed conservation costs that occur in the 7(b)(2) Case (the hypothetical case where conservation has not yet occurred) do in fact occur for the first year in which each conservation resource is selected to meet the 7(b)(2) Case loads. It is important to retain the same conservation expense and capitalization policies that are present in the Program Case (used for financial statement reporting purposes) in the 7(b)(2) Case. Sound business principles require that an entity properly classify expenditures that are in support of the conservation program such as staff salaries and general and administrative costs as normal operating expenses that are generally matched and recovered by the revenues of the same year. In contrast, conservation expenditures directly associated with the acquisition of specific conservation measures and related conservation savings should be capitalized and recovered over their useful economic life. Both Cowlitz and PPC *et al.* would choose to ignore the proper distinction of expensed versus capitalized costs.

Although the same capitalization and expense policies are maintained between the two Cases, it is appropriate that a deferral treatment of placing these expensed costs in rates is used in the 7(b)(2) Case, while the traditional recovery of expensed costs in the year incurred is followed in the Program Case. While BPA agrees that these expenditures are operating costs of the year incurred, and that such expenses are generally expensed in the Program Case, the fact that nine vintage years of conservation costs are selected from the section 7(b)(2)(D) resource stack with cumulative expensed costs of $325.1 million warrants the deferral treatment in the 7(b)(2) Case. Cowlitz Br., WP-10-B-CO-01, at 16, *citing* Doubleday *et al*., WP-10-E-BPA-39, at 14-15. In the Program Case, on the other hand, there is only one vintage year of conservation being acquired per year, and therefore the Program Case does not face the rate shock problem that occurs in the 7(b)(2) Case. Cowlitz Br., WP-10-B-CO-01, at 16. As Staff noted in rebuttal testimony, in the WP-07 Supplemental ROD BPA concluded that the most logical accounting and financing treatment for these expensed costs would be to defer these costs under SFAS No. 71 and to finance and recover their cost over an appropriate period. Doubleday *et al*., WP-10-E-BPA-39, at 22, *citing* WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 471-509, . Without the deferral treatment, the 7(b)(2) Case rates would experience a first year rate shock that would result in a 7 percent increase in first-year rates when compared to the 5-year deferral alternative. Doubleday *et al*., WP-10-E-BPA-39, at 15. The choice of a five-year deferral and amortization period achieves the best balance between the large increase in first-year costs that caused a rate spike and the desire to minimize the additional financing costs by recovering these costs over a short period of time. *Id*. at 14. It is reasonable to believe that the JOA in the 7(b)(2) Case would have elected the short-term deferral treatment to avoid this large increase in first-year rates. *Id*. at 15.

C. PPC's Arguments

PPC *et al*. argue that BPA should spread the total costs associated with each vintage conservation investment, both expensed and capitalized costs, over 15 years in the 7(b)(2) Case because that is the useful life of the resource. PPC *et al*. Br., WP-10-B-JP11-01, at 19. In the current case, BPA will defer, amortize, and finance the historically expensed portion of the 255 aMW of conservation resources selected from the section 7(b)(2)(D) resource stack in FY 2010 over a five-year period. This decision is based on weighing five criteria: 1) Resource Stack Composition; 2) Additional Financing Costs Associated with Deferring the First-Year Expensed Costs; 3) Number of Years Required to Recover Conservation Costs; 4) the Cost Treatment Comparability Between the Program Case and the 7(b)(2) Case; and 5) 7(b)(2) Case Rate Impacts. *Id*. The purpose of these criteria is described in Doubleday *et al*., WP-10-E-BPA-15, at 20. PPC *et al*. argue that, to the extent that BPA continues to include conservation as a resource to serve loads in the 7(b)(2) Case, the historical separation of expense and capital is not appropriate for how those resources are employed in the 7(b)(2) Case. *Id*. However, PPC *et al*. state the analysis and decision criteria have missed a central point. *Id*. They state the general principle at work is that all the costs associated with conservation resources in the section 7(b)(2)(D) resource stack are costs of acquiring a generating resource with a useful life of 15 years, over which the resource provides equal "output" in each year. *Id*. PPC *et al*. argue that given that the useful life of the resource is 15 years, the costs should be spread over the 15-year life of the resource. *Id*. To provide further clarification, PPC *et al*. state that BPA's actual historical categorization of conservation program expenditures into "expense" or "capital" does not dictate how the costs of conservation should be treated *in the section 7(b)(2)(D) resource stack*. *Id*. at 20. They claim the relevant factor is that the costs are going towards acquisition of assets with a useful life of 15 years. *Id*. PPC *et al*. conclude that as costs of an asset with a useful life of 15 years, any expenditures on conservation resources out of the section 7(b)(2)(D) resource stack should be evenly spread over the 15 year life. *Id*.

PPC *et al*. admit there is some extra interest expense over time using this method. *Id*. They argue, however, that sound, standard business and utility practice dictate that a resource should be paid for over its useful life, such that the customers that are getting the benefit of the resource are paying its costs. *Id*. PPC *et al*. claim any proposal to amortize the full costs of a resource over a significantly shorter period of time than its useful life would result in customers in the 7(b)(2) Case paying for a disproportionate share of the costs of the resource relative to its benefit to them. *Id*.

The IOUs disagree with PPC *et al*. and argue that BPA should not defer, amortize, and finance over a 15-year period the historically expensed portion of expenditures for conservation resources selected from the section 7(b)(2)(D) resource stack. IOU Br., WP-10-B-JP1-01, at 42. The IOUs state that, in essence, the direct testimony of PPC *et al.* asserts that conservation expenditures expensed in the Program Case should be projected to be deferred, amortized, and financed over a 15-year period in the 7(b)(2) Case. *Id*. The direct testimony of PPC *et al*., in effect, proposes that BPA ignore the difference between expense and capital for conservation in the section 7(b)(2)(D) resource stack in calculating the 7(b)(2) Case rate. *Id*. The IOUs conclude this would violate basic accounting and ratemaking principles. *Id*.

The IOUs state that the assertion of the direct testimony of PPC *et al*. that expensed conservation should be evenly spread over a 15-year life in determining the cost of the resources in the section 7(b)(2)(D) resource stack is erroneous. *Id*. The direct testimony of PPC *et al*. proposes that conservation expenditures that BPA determines should be expensed in the Program Case should be capitalized in the 7(b)(2) Case; PPC *et al.*'s direct testimony proposal is based on the erroneous assertion that the treatment of conservation expenditures in the Program Case "has no bearing in any way on how" such expenditure should be treated in the section 7(b)(2)(D) resource stack. *Id*. at 42-43. The PPC *et al*. direct testimony asserts that the "relevant factor is that all the costs are going towards acquisition of assets with a useful life of 15 years." *Id*. at 43. However, the "relevant factor" in deciding whether expenditures should be expensed in the 7(b)(2) Case is not whether the expenditures are "going towards acquisition of assets with a useful life of 15 years." *Id*. Rather, the relevant factor is whether there is any reason that conservation expenditures expensed in the Program Case should not be expensed in the 7(b)(2) Case in determining the costs of resources in the section 7(b)(2)(D) resource stack. *Id*. The APAC direct testimony provides no such reason. *Id*. Conservation expenditures that are expensed in the Program Case should also be expensed in the 7(b)(2) Case in determining the costs of resources in the section 7(b)(2)(D) resource stack. *Id*. In short, the direct testimony of PPC *et al*. rests on the unsupported premise that costs that are expensed in the 7(b)(2) Case should be treated differently (with respect to expensing or capitalizing such expenditures) than the same costs in the Program Case—with no explanation of why any "relevant factor" is different in this regard. *Id*.

The IOUs state that, as explained in their direct testimony and as discussed above, expensed conservation should be recovered in the 7(b)(2) Case in the first year it is drawn from the section 7(b)(2)(D) resource stack. *Id*. In any event, expensed conservation should not be assumed to be financed and amortized over a period as long as 15 years as asserted by PPC *et al*. or even as long as five years as BPA proposes. *Id*. at 44.

The IOUs argue that PPC *et al*. contend that Staff's evaluation of various financing options is irrelevant. *Id*. To the extent recovery of expensed conservation is spread over a number of years, a mismatch is created between expenses and their recovery. *Id*. For the 7(b)(2) Case, this mismatch is ameliorated if the expense recovery occurs within the Five-Year Period because the expenses are then included in the average 7(b)(2) Case rate. *Id*. Therefore, the percentage of the expensed conservation recovered during the Five-Year Period is an important criterion for evaluating financing options. *Id*.

The IOUs note that the direct testimony of PPC *et al*. criticizes a Staff "concern that the choice of a longer expense deferral period increases the difference in the revenue requirements amounts between the two Cases." *Id*. at 45. The IOUs state that a difference in the period over which expensed conservation is financed is not one of the Five Assumptions required by section 7(b)(2), nor is it a secondary effect of one of the Five Assumptions. *Id*. The IOUs state, as demonstrated in the IOUs' direct testimony and as discussed above, expensed conservation costs should be recovered in the year incurred. *Id*. They claim that is "the same accepted ratemaking technique used in the Program Case" for recovering conservation costs. *Id*. The IOUs state that if BPA nonetheless chooses to spread expensed conservation costs over a number of years in the 7(b)(2) Case, it is entirely appropriate that it minimize the difference in revenue requirements between the two Cases caused by this change in ratemaking technique. *Id*. at 45-46.

BPA notes that PPC previously raised this argument in BPA's WP-07 Supplemental rate proceeding. Doubleday *et al*., WP-10-E-BPA-39, at 13. The issue was addressed by BPA at length in the WP-07 Supplemental ROD. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 429-471. The WP-07 Supplemental Rate Proceeding record, which includes all litigants' arguments, has been incorporated into the record of this proceeding and is hereby incorporated as part of this response. BPA disagrees with PPC *et al*.'s assertion that "BPA has correctly acknowledged that the historical separation of expense and capital is not appropriate for how those resources are employed in the 7(b)(2) Case." PPC *et al*. Br., WP-10-B-JP11-01, at 19. As outlined above, BPA believes it is important to retain the same conservation expense and capitalization policies that are present in the Program Case (used for financial statement reporting purposes) in the 7(b)(2) Case. While retaining these consistent accounting capitalization and expense policies over time, it is still appropriate to defer and amortize expensed conservation costs over a period of five years in the 7(b)(2) Case due to the cumulative number of vintage conservation resources chosen and the rate spike that would result from the cumulative amount of first-year expensed conservation costs.

Decision

BPA will finance and amortize expensed conservation costs over five years in the 7(b)(2) Case.

Issue 2

Whether the change in the accounting and financing treatment of conservation costs that are expensed in the year incurred in the Program Case, but which are deferred and financed over a period of five years in the 7(b)(2) Case is a change arising from one of the Five Assumptions that prescribes the changes to be made to the 7(b)(2) Case.

Parties' Positions

The IOUs argue that a change in the period over which expensed conservation is financed and amortized in the Program case is not one of the Five Assumptions to be made for the 7(b)(2) Case under the Northwest Power Act. IOU Br., WP-10-B-JP1-01, at 14. The IOUs argue that, prior to the WP-07 Supplemental ROD, BPA recovered expensed conservation in the year it was incurred not only in the Program Case but also in the 7(b)(2) Case. *Id*. at 11. The IOUs state that there is no basis for using a different number of years for recovery of expensed conservation in the 7(b)(2) Case. *Id*. at 12.

BPA's Position

The establishment of the section 7(b)(2)(D) resource stack and the accounting and financing policies that govern the resources in the stack arise from section 7(b)(2)(D) of the Northwest Power Act. Doubleday *et al.*, WP-10-E-BPA-39 at 15.

Evaluation of Positions

The IOUs' principal position on this issue is that a difference in the period over which expensed conservation is financed is not one of the Five Assumptions required by section 7(b)(2), nor is it a secondary effect of one of the Five Assumptions. IOU Br., WP-10-B-JP1-01, at 14.
In discussing its general approach to the section 7(b)(2) rate test, BPA's Legal Interpretation states:

> This general approach will allow the 7(b)(2) Case to be modeled under the same accepted ratemaking techniques used in the Program Case. This approach will also avoid the modeling of a hypothetical world that attempts to reflect in extreme detail what would have occurred had the Northwest Power Act not been enacted.

Id., citing Study, WP-10-E-BPA-06, Attachment 1, at 5.

The IOUs state in their direct testimony, as discussed above in Issue 1, that expensed conservation costs should be recovered in the year incurred. The IOUs argue that expensed conservation should be recovered in the 7(b)(2) Case in the year in which it is incurred, "just like the Program Case treatment." IOU Br., WP-10-B-JP1-01, at 14. The IOUs state that prior to the

WP-07 Supplemental ROD, BPA recovered expensed conservation in the year it was incurred not only in the Program Case but also in the 7(b)(2) Case. *Id.* at 11. The IOUs note that BPA continues to properly follow the practice of recovering expensed conservation in the Program Case in the year that it is incurred. *Id.* They claim there is no basis for using a different number of years for recovery of expensed conservation in the 7(b)(2) Case. *Id.* The IOUs argue, in any event, that BPA's concern with recovering expensed conservation in one year in the 7(b)(2) Case focuses on the effects of such recovery in FY 2010, the first year of the Five-Year Period. *Id.* at 15. They state Staff has presented no rationale for financing expensed conservation over more than one year for any years other than FY 2010. *Id.* The IOUs assert that even if BPA decides that expensed conservation for FY 2010 should be financed over a period longer than one year to avoid what Staff characterizes as a price "spike" in 7(b)(2) Case costs for that year, expensed conservation for all other years in the 7(b)(2) Case should be recovered in one year, just as in the Program Case. *Id.*

BPA disagrees with the IOUs' assertion that a change in the period over which expensed conservation is financed and amortized in the Program Case is not one of the five assumptions to be made for the 7(b)(2) Case under the Northwest Power Act. Doubleday *et al.*, WP-10-E-BPA-39, at 15. Section 7(b)(2)(E) explicitly states that the 7(b)(2) Case is to assume "the quantifiable monetary savings … resulting from reduced public body and cooperative financing costs as applied to the total amount of resources … identified under subparagraph [7(b)(2)](D) of this paragraph, … are not achieved." 16 U.S.C. § 839e(b)(2)(E). Both the Legal Interpretation and the Implementation Methodology are clear that this means BPA financing is not applied to resources in the section 7(b)(2)(D) resource stack. The establishment of the section 7(b)(2)(D) resource stack and the accounting and financing policies that govern the resources in the stack arise from one of the five assumptions (section 7(b)(2)(D) of the Northwest Power Act).

During FY 1985-2001, BPA's accounting treatment regarding the useful life over which capitalized conservation investments should be amortized was 20 years, using the straight-line method for financial statement reporting purposes. Doubleday *et al.*, WP-10-E-BPA-39, at 16. This accounting policy was used in both the Program Case and the 7(b)(2) Case. *Id.* In FY 2002, the decision was made to adopt the declining years amortization treatment for ConAug Conservation investments over the Subscription Contract period for financial reporting purposes. *Id.* In BPA's WP-02 and WP-07 rate cases, 1) the Program Case continued to amortize the historical capitalized costs pertaining to FY 1985-2001 over 20 years; 2) ConAug Conservation investments made during FY 2002-2006 were amortized using the declining years method; and 3) starting in FY 2007, BPA adopted a third amortization treatment for conservation investments of 5 years using the straight-line method. *Id.* The change in accounting amortization period for conservation investments occurring in FY 2007 was primarily due to the need to replenish U.S. Treasury borrowing authority. *Id.* In contrast, during the entire FY 1985-2015 time period, the 7(b)(2) Case used an accounting amortization useful life determination that matched the composite useful life of conservation investments contained in the Council's Plan (preferred list of conservation investments), which was 20 years for FY 1985-2001 and 15 years for time periods after FY 2001, as determined in the WP-07 Supplemental Rate Proceeding. *Id.*

Rate cases since FY 2001, including the present case, continue to use different accounting and financing periods associated with capitalized conservation investments between the two cases.

Id. at 17. It was a correct determination that the JOA in the 7(b)(2) Case would have followed an accounting treatment for capitalized conservation costs that was based on an objective independent determination of useful life, and the Council's useful life determination fits this requirement. *Id.* It was also a correct determination in the Program Case (which follows BPA's accounting and financial policies used for financial statement reporting purposes) that the amortization/financing policy of amortizing and financing capitalized conservation over 5 years was appropriate to be responsive to BPA's need to sustain access to U.S. Treasury borrowing authority. *Id.*

In the 7(b)(2) Case, the JOA's access to U.S. Treasury borrowing authority is not a limitation, and this concern should not drive the borrowing and amortization policies for that Case. *Id.* Similarly, one would not choose to have the financing and accounting policies used for financial statement reporting purposes determined by the hypothetical world of section 7(b)(2). *Id.* It would be inappropriate for the accounting and financing policies of one Case to dictate the accounting policies and treatments that must be followed by the other case. *Id.* Thus, BPA's policy since FY 2001 has been to allow the conservation accounting and financing policies governing the Program Case and the 7(b)(2) Case to be different. *Id.*

In the WP-07 Supplemental ROD, BPA stated "The Act states nothing directly and implies very little concerning the nature of BPA's accounting and financing policies for conservation expenditures, although it does require that the Administrator implement the Act in a sound and businesslike manner. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 477, *citing* 16 U.S.C. § 839f(b)." *Id.* The Supplemental ROD also stated that:

> From a ratemaking perspective, the JOA and its member COUs would adopt a balanced approach in dealing with the upward rate pressures associated with the high first-year costs of conducting a large (approximately 255 aMW in the WP-10 Case) conservation program and concerns over accumulating substantial balances of deferred regulatory assets that would be have to be recovered from future rate periods. *Id.* A balanced and prudent approach would be to capitalize and finance the smaller portion of direct acquisition costs (approximately 32 percent of total conservation costs in WP-10 Case) of the conservation program over their useful life (15 years), while spreading the large amount of first-year expensed costs (68 percent of total conservation costs in WP-10 Case) over a one-year to useful-life period based on the conservation resources selected from the resource stack and their relationship to the total package of resources selected to meet 7(b)(2) Customer loads in the prospective rate case.

WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 498-499. In the present rate case, the treatment from the perspective of the JOA in the 7(b)(2) Case continues this balanced approach in selecting the deferral and financing period for the expensed conservation costs. Doubleday *et al.*, WP-10-E-BPA-39, at 18. This balanced approach mitigates the rate spike associated with the cumulative expensed costs associated with nine vintage conservation resources at a reasonable level of additional interest expense and a reasonably short recovery period. *Id.* The short recovery period mitigates the potential for accumulating successive increments of deferred costs that could create upward rate pressure for future rate periods. *Id.* As noted above, the accounting and financing policies that govern the section 7(b)(2)(D) resource stack are independent of the accounting and financing policies that govern conservation resources in the Program Case. *Id*. The establishment of the section 7(b)(2)(D) resource stack arises from section 7(b)(2)(D), and in order to implement this assumption it is necessary to develop accounting policies and procedures governing resources in the stack that are responsive to the operating circumstances of the JOA in the prospective rate case. *Id*.

The 7(b)(2) Case accounting treatment of deferring expensed costs and financing them over the deferral period is also consistent with the provisions of the Implementation Methodology: "For conservation resources acquired by BPA, the financing benefits may include an increased amount of debt financing compared to the Program Case. The amount of debt financing assumed in the 7(b)(2) case will be determined in the relevant rate case." *Id.,* at 18-19, *citing* Study, WP-10-E-BPA-06, Attachment 2, at 9.

The IOUs' secondary issue with 7(b)(2) accounting policies is that the 7(b)(2) Case accounting policy of deferring expensed conservation costs over five years should only be applied to the first year of the rate test period FY2010, because that was the only year in the Initial Proposal for which multiple years of vintage conservation investments were selected. While that is true of the Initial Proposal and the Final Proposal, it might not be true in future rate cases. Businesses in general, and regulated utilities specifically, adopt broad comprehensive accounting policies that will cover a broad set of alternatives as opposed to adopting a separate accounting policy for individual investments or changing the policy of how to treat identical or similar investments from one year to the next. Adopting a general comprehensive set of accounting policies for conservation investments that includes the capitalization and amortization of capitalized costs over 15 years and the deferral and amortization of expensed costs over 5 years, which apply to all years of the rate test period, provides a broader and more robust set of accounting policies. The JOA and its member utilities would have adopted this set of accounting policies in the beginning of FY 2010 for a period of time that was not limited by the 7(b)(2) rate test. At that point in time they would not have known with certainty whether they would have faced the situation of having to acquire additional large conservation investments in subsequent years of the rate test period. The IOU proposal of adopting a deferral policy that applies to only the first year of the rate test period depends on having perfect foresight of how events would unfold in subsequent years. Because businesses do not possess perfect foresight of how events will unfold, they choose to adopt broad comprehensive accounting policies that will cover a range of alternatives for a number of years. In addition, firms do not choose to constantly change their accounting policies from year to year due to the consistency principle of accounting. Constantly changing accounting policies from year to year compromises the comparability of their financial results between years. For all of these reasons, BPA cannot accept the IOUs' proposal to adopt a deferral accounting policy that applies to only the first year of the rate test period.

In conclusion, the different accounting treatment for expensed conservation costs in the 7(b)(2) Case is necessary to adopt the change in accounting policy to be responsive to the JOA's operating circumstances in the 7(b)(2) Case. *Id*. Just as it was reasonable for BPA to adopt a 5-year amortization and financing period for capitalized conservation for financial reporting purposes for use in the Program Case in 2007, it is also reasonable to adopt the deferral treatment for expensed conservation costs in the 7(b)(2) Case. *Id*. It is not reasonable to assume that the JOA would have elected an accounting policy that would have placed the cumulative amount of expensed costs associated with nine conservation resources into the FY 2010-2011 7(b)(2) rate period. *Id*. It is necessary to adopt this change in the accounting treatment for expensed costs in order to implement the section 7(b)(2)(D) resource stack and the selection of nine conservation resources in the first year of the rate period. *Id*. This position is consistent with BPA's past practice of establishing different amortization periods for capitalized conservation costs in the two Cases, which has been followed since FY 2002. *Id*.

Decision

BPA's decision to defer and finance expensed conservation costs over a period of five years in the 7(b)(2) Case while continuing to expense conservation costs in the year incurred in the Program Case is a change that arises from one of the Five Assumptions. Establishing the section 7(b)(2)(D) resource stack and the accounting policies and procedures governing resources in the stack that are responsive to the operating circumstances of the JOA in the prospective rate case is required to implement section 7(b)(2)(D) of the Northwest Power Act. BPA will use a comprehensive set of accounting policies covering conservation investments and activities. This set of policies will apply to the entire rate test period.

Issue 3

Whether BPA uses the correct financing rates in calculating debt service for the 7(b)(2) Case.

Parties' Positions

The IOUs state that, paradoxically, under the Initial Proposal, conservation debt service costs are lower in the 7(b)(2) Case than in the Program Case, even though BPA is required to assume that financing benefits were not achieved in the 7(b)(2) Case. IOU Br., WP-10-B-JP1-01, at 14.

BPA Staff's Position

The actual financing costs present in the Program Case are reflected correctly in the revenue requirements and the Cost of Service Analysis for that Case. The Financing Study prepared by BPA's financial advisor is performed correctly and the projected interest rates from the study are used to finance the resources in the section 7(b)(2)(D) resource stack. Section 7(b)(2) Rate Test Study, WP-10-E-BPA-06, Attachment A. All financing benefits/disbenefits attributable to section 7(b)(2)(E)(i) are correctly reflected in the performance of the 7(b)(2) rate test

Evaluation of Positions

he rate test provisions of section 7(b)(2)(E)(i) of the Northwest Power Act are correctly implemented in conducting the rate test. The financing rate used to finance capitalized conservation costs in the 7(b)(2) Case is the interest rate of 4.68 percent determined by BPA's independent financial advisor, Public Financial Management (PFM). This rate is contained in Table A of the Study, WP-10-FS-BPA-06, Appendix A at 5. This tax exempt rate is used to finance capitalized conservation costs over 15 years in the 7(b)(2) Case. This rate is the correct rate associated with higher financing costs that occur due to the absence of BPA's resource backing in the 7(b)(2) Case. If a BPA conservation purchase contract is used to acquire conservation for the Program Case using customer-issued tax exempt bonds, PFM projects a lower interest rate of 4.48 percent. As Note 3 to Table A states, "During the 2010 Power Rate Case study period FY 2010–2015, BPA projects that it will borrow $262 million for conservation investments using 5-year maturities with a weighted average (taxable) interest rate of 5.32 percent. The bonds will be issued through the U.S. Treasury so they are not comparable to the tax exempt rates included in the table." *Id*. The correct 5-year tax exempt rate of 3.69 percent contained in Table A is used to finance the deferred conservation expenses over 5 years. The financing cost impacts associated with section 7(b)(2)(E)(i) of the Northwest Power Act is correctly incorporated into the calculation of conservation debt service costs in the 7(b)(2) Case.

The financing benefits that would not have been achieved in the 7(b)(2) Case pursuant to section 7(b)(2)(E)(i) of the Northwest Power Act generally would have been predicated with the JOA using customer-issued tax exempt bonds to acquire the conservation savings or a generating resource. In that circumstance, the JOA would have agreed to enter into a long-term power purchase agreement covering the resource where the revenue stream from the resource purchase would secure the bonds. This event historically occurred in the Program Case and is reflected in the Program Case revenue requirements. Only the Cowlitz Falls Hydro resource in the section 7(b)(2)(D) resource stack fits this description. One can see from the financing study, that there is a higher interest rate of 5 basis points (.05 percent) charged to finance this resource in the 7(b)(2) Case. Section 7(b)(2) Rate Test Study, WP-10-FS-BPA-06, at A10-A12. This financing difference is reflected in the cost of this resource between the two Cases as documented in Appendix C to the Study at pages C-78 through C-82. However, because all other resources in the section 7(b)(2)(D) resource stack are assumed to be financed by the JOA using tax exempt bonds with projected interest rates that are lower than the interest rates associated with U.S Treasury-issued bonds used to finance resources in the Program Case, the relationship that the IOUs observe, that financing costs are lower in the 7(b)(2) Case, is correct. Section 7(b)(2)(E)(i) does not change the actual financing costs present in the Program Case. Should BPA acquire conservation through its customers using their tax exempt bonds in the future, the provisions of section 7(b)(2)(E)(i) would then be applicable and reflected in a higher financing cost in the 7(b)(2) Case.

Decision

BPA will use the updated financing rates in calculating debt service for the 7(b)(2) Case.

Issue 4

Whether the criteria for determining the deferral and financing period for expensed conservation costs are appropriate.

Parties' Positions

PPC *et al*. argue that Criterion Number 2, "Financing Cost Impacts," overstates the impact of financing because it does not appear to take into account the time value of money. PPC *et al*. Br., WP-10-B-JP11-01, at 20. PPC *et al*. contend that Criterion Number 3, "Cost Recovery," is not relevant to determining how a JOA would handle the costs of conservation resources. *Id*. at 21. PPC *et al*. assert that Criterion Number 4, "Comparability of Costs," inappropriately looks at the effect of implementing the Five Assumptions, and makes an adjustment due to the "wrong" outcome appearing from those assumptions. *Id*. at 22; PPC *et al*. Br. Ex., WP-10-R-JP12-01, at 7-8.

<u>BPA Staff's Position</u>

BPA Staff's proposed criteria for determining the financing of conservation are appropriate. Doubleday *et al*., WP-10-E-BPA-39, at 26.

<u>Evaluation of Positions</u>

A. Criterion No. 2 – Financing Cost Impacts

PPC *et al*. state that in comparing different conservation financing options in the 7(b)(2) Case, Staff calculates interest expenses from deferring the historically expensed costs and then comparing those to the historical expense. PPC *et al*. Br., WP-10-B-JP11-01, at 20. They argue this comparison overstates the impact of financing because it does not appear to take into account the time value of money. *Id*. PPC *et al*. contend BPA should apply a net present value calculation to the interest expenses to make the comparison valid. *Id*. Staff states in rebuttal testimony that it intends to revise the analysis by restating the cash flows in constant 2010 year dollars by using the Inflator/Deflator indices that are outlined in the errata corrections designated WP-10-E-BPA-06-E01 to page B-5 of the Study, WP-10-E-BPA-06. *Id., citing* Doubleday *et al*., WP-10-E-BPA-39, at 20. Staff states that it does not expect the changes to result in a different conclusion for which financing option is most appropriate. PPC *et al*. Br., WP-10-B-JP11-01, at 20. PPC *et al*. argue the fact that Staff's current analysis overstates the cost impact of financing conservation in the 7(b)(2) Case over the useful life of the resource argues in favor of the agency adopting PPC *et al*.'s proposal. *Id*. at 20-21.

PPC *et al*. are correct that there are differences in the time value of money that are not taken into account in comparing the differences in financing cash flows. Doubleday *et al*., WP-10-E-BPA-39, at 20. The analysis is performed in the following manner (reflective of Initial Proposal interest rates that will be revised for the updated Appendix A Financing Study dated June 3, 2009 for the final studies):

- The vintage conservation resources in the section 7(b)(2)(D) resource stack were used to analyze all alternatives, and all resources were stated in FY 2010 dollars.
- All resources were selected from the section 7(b)(2)(D) resource stack in the same order and in the same amounts contained in the Initial Proposal.
- Conservation resources costs were adjusted for inflation projections using the inflator/deflator values contained at page B-5 of Appendix B to the Study as corrected by WP-10-E-BPA-06-E01.
- The interest rate used to finance the capitalized conservation expenditures over 15 years is 4.57 percent across all alternatives. The short-term interest rates used for financing the deferred expensed conservation costs is based on the interpolation direction on page 16 of the Financing Study. *See* Study, WP-10-E-BPA-06, Appendix A.

- The annual debt service payment amount is calculated with increasing principal/decreasing interest expense over the term of the debt, similar to mortgage-based financing. Once the annual debt service payment is calculated, it remains fixed over the financing period.

BPA will revise the analysis for the final studies by restating the cash flows for the time value of money associated with the financing costs that are fixed mortgage based payments that are determined in the year the investment is selected from the resource stack by using the Inflator/Deflator indices that are outlined in the errata corrections designated WP-10-E-BPA-06-E01 to page B-5 of the Study, WP-10-E-BPA-06. *Id.* It is not appropriate to speculate on the cost of capital or the appropriate discount rate the JOA would use, which would have been used to perform a net present value analysis of the six different alternatives. *Id.* at 20-21. The JOA would also take into account the additional cost associated with the deferral of the principal in terms of additional borrowings that would be incurred, or additional capital that would be raised, to be able to undertake additional utility investments of the JOA and its member utilities stemming from the deferral of the return of principal. *Id.* at 21. This cost associated with the delay in replenishing reserves/working capital is not quantified in the analysis. *Id.* BPA desires to keep the analysis simple and omit unnecessary complexity. *Id.*

The adjustment for the time value of money would change the magnitude of the dollar differences between the different alternatives, but it would not change the outcome of the analysis, which is the conclusion that "[t]he amount of additional interest expense and cumulative rate impacts of deferring these costs into later rate periods support the choice of a shorter deferral period." *Id., citing* Doubleday *et al.*, WP-10-E-BPA-15, at 21.

PPC *et al.*'s principal position that the entire cost of vintage conservation investments should be spread over a 15-year period would render the overall objective of determining the appropriate amortization and financing period for expensed costs moot. BPA does not agree with PPC's position on expensed conservation costs in the 7(b)(2) Case. BPA believes it is important to retain the same conservation expense and capitalization policies that are present in the Program Case (used for financial statement reporting purposes) in the 7(b)(2) Case. Sound business principles require that an entity properly classify expenditures that are in support of the conservation program such as staff salaries and general and administrative costs as normal operating expenses that are generally matched and recovered by the revenues of the same year. In contrast, conservation expenditures directly associated with the acquisition of specific conservation measures and related conservation savings should be capitalized and recovered over their useful economic life. BPA has consistently followed the same expense and capitalization determination policies concerning conservation costs for over 27 years. Both Cowlitz and PPC *et al.* would choose to ignore the proper distinction of expensed versus capitalized costs. BPA rejected the PPC *et al.*'s position in the WP-07 Supplemental ROD. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 429-471. The WP-07 Supplemental rate proceeding record, which includes all litigants' arguments, has been incorporated into the record of this proceeding and is hereby incorporated as part of this response.

Contrary to the position of Cowlitz and PPC *et al.*, BPA finds Criterion No. 2 – Financing Cost Impacts is a useful metric in determining the deferral and financing period for expensed costs in the 7(b)(2) Case. Criterion No. 2, along with Criterion No. 3 – Cost Recovery, are important in balancing the benefits of reducing the rate spike associated with the selection of multiple conservation investments in a single year against the increased financing costs that are incurred and the delay in recovering these funds for the JOA's reinvestment in its utility operations.

B. Criterion No. 3 – Cost Recovery

PPC *et al*. state that under the third stated criterion, BPA weighs the various financing options by the total percentage of conservation costs that each option recovers during the rate test period. PPC *et al*. Br., WP-10-B-JP11-01, at 21. They state this inquiry is inappropriate, and tends to make the rate test results depend on subjective preferences as to how much the IOUs should get under the REP. *Id*. They claim this third criterion is not relevant to BPA's stated goal of determining how a JOA would handle the costs of conservation resources. *Id*. PPC *et al*. argue the "Rate Test Period" is an interpretation of the language of section 7(b)(2) which is completely exogenous to the hypothetical world in which the JOA is deemed to be making its decisions. *Id*. They assert that, stated differently, this criterion incorrectly assumes that the construct of the "Rate Test Period" itself would have significance on the question of what the costs of serving the general requirements of the preference customers are during the rate test period. *Id*.

PPC *et al*. state that in rebuttal testimony, Staff acknowledged the validity of this point, but continued to use the criterion in its analysis because:

> Following prudent business practices, we propose that the JOA would choose a short time period of 3 to 7 years over which to perform the analysis, because of the fact that 66.24 percent of the costs were expensed costs that would normally be recovered in the year incurred.

Id., *citing* Doubleday *et al*., WP-10-E-BPA-39, at 21-23. PPC *et al*. claims Staff has not provided any valid reasoning why the JOA would arbitrarily establish some "short time period" to perform an analysis of what percentage of the historically expensed costs were recovered over the period, rather than follow standard, prudent utility and ratemaking practice of spreading the costs of a resource over its full useful life, such that customers pay for a resource in proportion the benefit they receive from it. *Id*. at 22.

In response to PPC *et al*., Staff stated its position on the accounting for, and financing of, conservation expenditures at great length in the WP-07 Supplemental ROD. Doubleday *et al*., WP-10-E-BPA-39, at 22, *citing* WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 471-509. Staff's position on the accounting for, and financing of, conservation costs is different than PPC *et al*.'s position as outlined above under Criterion No. 2 and as outlined in the above-cited rebuttal testimony.

In the WP-07 Supplemental ROD, BPA noted 1) the large number of vintage conservation programs that were being selected from the section 7(b)(2)(D) resource stack in the first year of the rate test period; 2) that a substantial portion (68.06 percent of the Final Proposal's selected Conservation Costs – Appendix D at D-29) of the conservation resource expenditures are expensed costs; and 3) that the JOA in the 7(b)(2) Case would have mitigated the first year "rate spike" that would occur if these expensed costs were placed in rates. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 471-509. BPA concludes that the most logical accounting and financing treatment for these expensed costs would be to defer these costs under SFAS No. 71 and to finance their cost over an appropriate period. Given the fact that the JOA would have chosen to defer these expensed costs and to finance them over a period of years, BPA's objective is to develop criteria that would be useful to the JOA decision-makers in determining the period of years to finance and recover these expensed costs. Doubleday *et al*., WP-10-E-BPA-39, at 22. Following prudent business practices, BPA finds that the JOA would choose a short time period of 3 to 7 years over which to perform the analysis, because of the fact that 66.24 percent of the costs were expensed costs that would normally be recovered in the year incurred. *Id*. at 22-23. BPA analyzes the cost recovery over 6 years because it provides a convenient time period associated with the section 7(b)(2) rate test in the current rate case, and because various rate case parties would want to know the amount of costs that are recovered during the rate test period as well as the costs that are recovered beyond the rate test period.

BPA agrees that the 6 year period would be exogenous to the JOA's frame of reference. *Id*. at 23. Although the recovery amounts would be different, the conclusions drawn from the analysis using a slightly different short-term time period would be the same. *Id*. The decisionmaker would want to establish what percentage of the total conservation costs is recovered using the different deferral periods by a "time-certain," and it would likely use a 3-year to 7-year period in performing the analysis. *Id*. The percentage of total conservation costs recovered is only one of two cost recovery metrics that is considered under the Cost Recovery Consideration Criteria. *Id*. A weighted average recovery period analysis is also presented in the Study, WP-10-E-BPA-06, Appendix B, at B-9. *Id*. This second metric is not constrained by the "time-certain" limitation of the first metric. Both metrics are considered in analyzing the deferral period and in proposing to defer and finance the expensed conservation costs over 5 years. *Id*. It is reasonable to conclude that the JOA would weigh the benefits of reductions in 7(b)(2) Customer rates quantified by Criterion #5 against the additional interest expense (Criterion #2) and the increased recovery time (Criterion #3) associated with longer deferral periods. *Id*. A longer discussion of the analysis of the five decision criteria can be found in the response to the IOUs' direct case in Issue 1 above.

C. Criterion No. 4 – Comparability of Costs

PPC *et al*. argue that Criterion No. 4, "Comparability of Costs," inappropriately looks at the effect of implementing the Five Assumptions, and makes an adjustment due to the "wrong" outcome appearing from those assumptions. PPC *et al*. Br., WP-10-B-JP11-01, at 22. Regarding the fourth criterion, Staff states:

> Although the accounting and financing treatments are different between the two Cases, there is concern that the choice of a longer expense deferral period increases the difference in the revenue requirements amounts between the two Cases.

Id., *quoting* Doubleday *et al*., WP-10-E-BPA-15, at 23. PPC *et al*. do not understand Staff's concern given that the difference in revenue requirements between the two cases is as a result of attempting to implement the five assumptions directed by section 7(b)(2). PPC *et al*. Br., WP-10-B-JP11-01, at 22. They argue that choosing to minimize or mitigate the difference in revenue requirements as criteria appears to be in direct conflict with the purpose of the statute. *Id*. Additionally, PPC *et al*. claim that any concerns BPA may have about differences created between the Program Case and 7(b)(2) Case revenue requirements are, again, exogenous to the hypothetical world in which, under BPA's construct, the JOA is deemed to be operating and should be excluded on that basis as well. *Id.*

In response to the PPC *et al*. argument, BPA has a valid concern over the comparability of cost and financing treatments between the two cases. Doubleday *et al.*, WP-10-E-BPA-39, at 24. In an "ideal world" associated with performing the 7(b)(2) rate test, both the Program Case and the 7(b)(2) Case would have identical amortization periods associated with capitalized costs. *Id.* BPA's Program Case amortization time period of 5 years was chosen primarily due to the need to "replenish" borrowing authority to sustain the financing of capitalized conservation expenditures. *Id.* In the 7(b)(2) Case, BPA has consistently used the composite useful life of conservation resources developed by the Council to finance and amortize conservation resources, which is currently over 15 years. *Id.* Thus, capitalized costs that comprise 30.84 percent of the total conservation costs (Appendix D –Final Study at D-29) selected from the section 7(b)(2)(D) resource stack during the rate test period are amortized and financed over 5 years in the Program Case, and over 15 years in the 7(b)(2) Case. *Id.* Both amortization and financing periods are appropriate for the respective cases. Even though the two different amortization periods are correct for each respective Case, the longer 7(b)(2) Case amortization period advantages that Case in performing the rate test.

BPA does not seek to diminish the differences between the amortization periods for expensed conservation costs in the two cases. *Id.* Prior to the WP-07 Supplemental rate proceeding, BPA's practice of recovering in rates expensed conservation costs in the year incurred was followed in both the Program Case and the 7(b)(2) Case. *Id.* The decision to defer and finance the large amount of "first year" expensed conservation costs in the 7(b)(2) Case is the correct accounting treatment for the 7(b)(2) Case in order to mitigate the first year "spike" in rates. *Id.* The treatment of expensing these costs as incurred in the Program Case is also the correct accounting policy in the Program Case and is also followed by many 7(b)(2) Customers. *Id.*

Although it is true that the creation of the section 7(b)(2)(D) resource stack and the corresponding accounting and financing policies associated with those resources is the result of one of the five assumptions, BPA is concerned that the choice of the deferral period will impact the rate test results. *Id.* at 24-25. It is due to this concern over the issue of comparability of conservation accounting treatments, that one of the five criteria addresses cost comparability. *Id.* at 25. Although BPA is not attempting to eliminate the differences attributable to the accounting and financing policies between the two Cases, BPA cannot ignore the fact that the choice of setting the deferral period for expensed conservation costs will have an impact on the rate test. *Id.* Given that the 7(b)(2) Case is already advantaged by the longer amortization period for capitalized costs, and the choice of deferring the expensed costs also advantages the 7(b)(2) Case, it is appropriate that the comparability criterion is present to gauge the reasonableness of the difference in costs stemming from the different accounting policies. Again, BPA is not seeking to diminish the differences between the two Cases or to make them more comparable; the objective of this criterion is to gauge whether the difference in costs due to different accounting policies is reasonable. The comparability criterion and the related analysis of the different conservation costs that are present in the two Cases informs all rate case parties. It gives parties a tool to gauge whether the deferral and financing period for expensed costs in the 7(b)(2) Case is reasonable given the importance that this decision can have on the 7(b)(2) rate test results. *Id*. Based upon the comments received from other rate case parties in their direct cases regarding the comparability of conservation costs, it is apparent that this criterion is serving a useful purpose. *Id*.

BPA agrees that this criterion is exogenous to the world that the JOA decisionmakers would be concerned about. *Id*. The other four criteria address the frame of reference of the JOA decisionmakers. *Id*. As Staff notes in responding to the IOUs' direct case, the principal reason the JOA and its member utilities would not choose Alternative 6 (Deferring and Financing the Expensed Costs over Fifteen Years) is due to the fact that the additional amount of interest expense and the long recovery period for costs that are normally expensed in the year incurred would not be a prudent or sound business decision. *Id*. at 33. Due to the rate spike that would occur from expensing multiple years of vintage conservation investments in the first year of the rate test period the JOA and its customers would have also reject Alternative 1 – Expensing the Costs in the Year Incurred. *Id*. at 31. Contrary to PPC's assertion that, "BPA inappropriately looks at the effect of implementing the Five Assumptions, and makes an adjustment due to the "wrong" outcome appearing from those assumptions," the decision to amortize the expenses over a 5-year period is made solely from the perspective of the JOA and its members. Criterion No. 4 – Cost Comparability does not influence the choice of the 5-year alternative. However the comparability criterion does serve as a useful frame of reference or benchmark to test the overall reasonableness of the cost of conservation in the 7(b)(2) Case. The cost treatment comparability criterion reinforces the decisions made from the perspective of the JOA not to choose Alternatives 1 and 6 in favor of Alternatives 2-5. *Id*. at 35. Alternatives 1 and 6, in addition to being inferior choices from the perspective of the JOA, would also decrease the comparability of conservation costs between the two cases to a significant degree. *Id*.

PPC *et al*. note that in rebuttal, Staff responds to PPC *et al*.'s position on this point with insistence that it is necessary to include this criterion so as to allow parties to gauge whether the result of different deferral and financing periods for expensed costs between the Program Case and 7(b)(2) Case are "reasonable." PPC *et al*. Br., WP-10-B-JP11-01, at 22. PPC *et al*. understand Staff's position, therefore, to be that the criterion is necessary to impose a subjective check on whether BPA is getting a reasonable result from the rate test after implementing the Five Assumptions required by the Act. *Id*. at 22-23. Again, PPC *et al*. do not believe it is proper for BPA to impose criteria that essentially allow it to determine what the appropriate level of the REP is through an additional "check" it places on the results it gets after following the Five Assumptions. *Id*. at 23.

In their Brief on Exceptions, PPC *et al*. note that they previously argued that it is inappropriate for BPA to implement criteria for determining the capitalization/expense split for conservation costs in the rate test that essentially allow the agency to choose the split based on the impact that the various options have on the rate test results. PPC *et al*. Br. Ex., WP-10-R-JP12-01, at 7-8. PPC *et al*. claim that in the Draft ROD, BPA acknowledges that the basis for the agency's criteria is the agency's desire to have control over what the rate test produces. *Id*. at 8, *citing* Draft ROD, WP-10-A-01, at 135. PPC *et al*. assert that these statements acknowledge BPA's proposed approach of altering the conservation/expense split in order to achieve a level of IOU benefits determined by BPA. *Id*. PPC *et al*. assert that BPA is not entitled to impose criteria into the rate test that expressly make the assumptions subservient to BPA's subjective call about the appropriate level of IOU benefits. *Id.* PPC *et al.* state that the rate test was intended to be an objective rate comparison, and BPA's decisions about the appropriate assumptions should be based on its best interpretation of the statutory text, not its subjective determination of what the rate test should produce. *Id., citing, e.g.*, S. Rep. No. 96-272, 96th Cong., 1st Sess. at 61 (1979) ("The specific rate limit factors are objective in nature.").

BPA agrees that the 7(b)(2) rate test is largely an objective test; however, given the enormous complexity of implementing the rate test, there are inevitably issues that lack specific objective guidance. The choice of the conservation expense deferral period is such an issue. In such instances the Administrator must exercise his judgment and discretion, in conjunction with the record and legal guidance, in order to resolve such issues. Instead of a desire to determine the outcome of the rate test, BPA's decision to include the comparability cost information is an effort to ensure that the 7(i) rate case proceeding is transparent and to allow all parties to have the necessary information to inform their positions in the current and future rate cases.

In addition, PPC *et al.* have misunderstood and mischaracterized how BPA accounts for conservation expenditures in the 7(b)(2) Case. PPC *et al.* incorrectly refer to the five criteria that BPA has developed to help decide the appropriate number of years over which expensed conservation resources should be deferred and financed as the "criteria for determining the capitalization/expense split for conservation costs." PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 7. The term "capitalization/expense split" is incorrect and misleading. BPA uses the same accounting policies in the 7(b)(2) Case and the Program Case for financial reporting purposes to determine which conservation costs are appropriately characterized as costs that are expensed in the year that they are incurred, and those intangible expenditures that are capitalized under SFAS No. 71. BPA does not change the characterization of costs classified as operating expenses, which are normally expensed in the year incurred, and those that are capitalized and amortized over a period of years. As noted above, BPA's Program Case amortization time period of five years is chosen primarily due to the need to "replenish" borrowing authority to sustain the financing of capitalized conservation expenditures. Doubleday *et al.*, WP-10-E-BPA-39, at 24. In the 7(b)(2) Case, BPA has consistently used the composite useful life of conservation resources developed by the Council to finance and amortize conservation resources, which is currently over 15 years. *Id.* Thus, capitalized costs that comprise 30.84 percent of the total conservation costs (Appendix D to WP-10-FS-BPA-06A at D-29) selected from the section 7(b)(2)(D) resource stack during the rate test period are amortized and financed over five years in the Program Case, and over 15 years in the 7(b)(2) Case. *Id.* Both amortization and financing periods are appropriate for the respective Cases. Each of the two different amortization periods is correct for each respective Case. The longer 7(b)(2) Case amortization period lowers the 7(b)(2) Case rate levels, which increases the amount of 7(b)(2) rate protection. Draft ROD, WP-10-A-01, at 134.

Expensed conservation costs, which are appropriately expensed in the year incurred in the Program Case, are deferred and amortized in the 7(b)(2) Case, because 9 vintage years of historical conservation costs are incurred within the first year of the rate test period. As noted above and in the WP-07 Supplemental rate proceeding, the JOA would have chosen to defer the substantial amount of cumulative expensed costs and would have amortized and financed them over a short time period under SFAS No. 71 due to the large first-year spike in rates associated with this large conservation program. As mentioned above, the 7(b)(2) Case is already advantaged by the longer amortization period for capitalized costs. The choice of deferring the expensed costs in the 7(b)(2) Case also advantages the 7(b)(2) Case. In an "ideal world," both the Program Case and the 7(b)(2) Case would have identical amortization periods associated with capitalized costs, and there would be accounting treatments surrounding expensed costs that were roughly similar in their ability to recover such costs. The fact that the two Cases use different accounting policies associated with the amortization and recovery of capitalized and expensed conservation costs causes the cost streams of the two Cases to be less comparable with one another (there are other basic differences between the two Cases that also contribute to the costs streams being different). It is because of this lack of comparability of the cost streams that it is necessary to provide the comparability cost information that outlines the difference in conservation costs between the two Cases over the rate test period.

Thus, PPC *et al.* mischaracterize BPA's actions and intent in choosing to include the comparability cost criteria. Contrary to PPC's *ad hominem* characterization, the Draft ROD simply does not state that BPA that "desire[s] to have control over what the rate test produces." Indeed, the Draft ROD states that "BPA is *not* attempting to eliminate the differences attributable to the accounting and financing policies between the two Cases." Draft ROD, WP-10-A-01, at 134 (emphasis added). As described above, the JOA would have chosen to defer and finance the expensed conservation costs over a period of five years. The comparability cost criterion was used to confirm the reasonableness of this deferral time period, but it was not a direct consideration in reaching this decision. If BPA were actually trying to determine the level of IOU REP benefits, it would not disclose the comparability cost information to all rate case parties. As outlined above, BPA performs the comparability analysis in rate case study documents in order for the rate case process to be transparent and to ensure that the information is available to all rate case parties. BPA expects all rate case parties to use the comparability cost information as a gauge in making their own assessment as to whether the expense deferral period is reasonable to inform their arguments in the current rate case and in future rate cases. In order to help ensure that all parties have the ability to evaluate BPA's proposed choice of a 5-year deferral period, BPA chooses to provide the conservation cost comparability information.

BPA will continue to use all five criteria in analyzing and deciding the appropriate number of years that expensed conservation resources should be deferred and financed in treating these expenses as deferred charges under SFAS No. 71.

Decision

BPA will use all five criteria to assist in the determination of the appropriate deferral period to defer and finance expensed conservation costs.

10.4 Boardman Coal Plant

Issue 1

Whether the output from Power Resources Cooperative's 10-percent share of the Boardman Coal Plant should be included in the section 7(b)(2)(D) resource stack.

Parties' Positions

The IOUs argue that the output from PRC's 10 percent share of the Boardman Coal Plant should not be included in the section 7(b)(2)(D) resource stack. IOU Br., WP-10-B-JP1-01, at 16-22; IOU Br. Ex., WP-10-R-JP1-01, at 12.

BPA Staff's Position

BPA Staff believes the output from Power Resources Cooperative's 10 percent share of the Boardman Coal Plant should be included in the section 7(b)(2)(D) resource stack. Doubleday *et al*., WP-10-E-BPA-39, at 38-43.

Evaluation of Positions

The IOUs argue that the output from PRC's 10 percent share of the Boardman Coal Plant should not be included in the section 7(b)(2)(D) resource stack. IOU Br., WP-10-B-JP1-01, at 16-22. The IOUs note the Initial Proposal stated that "[t]he only 'Type 2' resource (7(b)(2) Customer resources not currently committed to regional loads) in the section 7(b)(2)(D) resource stack is Power Resources Cooperative's (PRC) 10 percent share of the Boardman Coal Plant, which is sold out of region to the Turlock Irrigation District in California." *Id*. To be included in the section 7(b)(2)(D) resource stack as a Type 2 resource, the resource must, at a minimum, be "owned or purchased by public bodies or cooperatives[.]" *Id*. The IOUs state that BPA appears to be arguing that either PRC and/or the 13 consumer-owned utilities that are members of PRC own the output from PRC's 10 percent ownership of the Boardman Coal Plant (the resource)—notwithstanding the fact that PRC and/or the 13 consumer-owned utilities sold such output to Turlock Irrigation District (Turlock)—based on BPA's reasoning in the WP-07 Supplemental ROD. *Id*. The IOUs claim BPA's reasoning is flawed. *Id*.

In responding to the IOUs' arguments it is helpful to establish the historical record concerning the PRC's 10 percent ownership interest of the Boardman Coal plant. Doubleday *et al*., WP-10-E-BPA-39, at 38. Power Resources Cooperative was originally organized as Pacific Northwest Generating Company (PNGC). PNGC acquired the 10-percent ownership interest from Portland General Electric Company in or around 1980, when the Boardman Coal Plant went into operation. *Id*. at 38-39. PNGC's operations concerning its ownership in the Boardman Coal plant were transferred to PRC in approximately 1995. *Id*. at 39. The generation and transmission functions of the former PNGC were transferred/assumed by PNGC Power in approximately 1997. *Id*. The ownership of PNGC, PRC, and the interests in the power generation of the Boardman Coal plant were represented by PNGC to BPA to have similar ownership interests prior to the time that PNGC Power was formed in 1997. *Id*.

Exhibit A to Staff's 7(b)(2) rebuttal testimony includes Contract No. DE-MS79-86BP92300 between BPA and PNGC and its member utilities dated February 27, 1987. *Id*. The contract provides for BPA to serve as agent for PNGC and its member utilities to schedule their share of the Boardman Project to short-term purchasers. *Id*. Exhibit C to the contract establishes the utilities' share/interest of the Boardman project output. *Id*. The contract states "Bonneville and each of the utilities have separately entered into a Power Sales Contract as specified in Exhibit C which provides for the sale of power at Bonneville's Priority Firm Rate to meet each utility's firm requirements for power." *Id*. This provision and the underlying individual utility contracts provided the consumer-owned utilities with preference power to replace the Boardman project power that was owned by each utility and dedicated to each utility's load in its 1981 Power Sales Contract's Firm Resource Exhibit (FRE). *Id*. Note 1 to Exhibit C of the Contract made each individual utility's power sales contract part of Contract No. DE-MS79-86BP92300. Section 10 of the contract covered the contract's payment provisions. *Id*. That section required each of the individual utilities to pay for all of the nonfirm displacement energy, surplus firm power, station service, and scheduling and management services for the Boardman project in relation to each utility's Project Share. *Id*. The contract is signed by each of the 13 utility principals and the general manager of PNGC. *Id*.

Exhibit B of Staff's rebuttal testimony includes two letters from BPA's Power Sales Office to PNGC dated August 11 and 30, 1989, concerning each consumer-owned utility's Firm Resource Exhibit. *Id*. at 40. The letter of August 30, 1989, states

> This is to notify you that the Bonneville Power Administration has approved each Pacific Northwest Generating Company member's request to remove the 5(b)(1)(B) contractual Boardman resource from their Firm Resource Exhibits (FRE) effective July 1, 1980 and for all subsequent years pursuant to section 12(b)(9) of the Power Sales Contract.

Id. Exhibits A and B establish that the membership of PNGC at that time and the ownership of the Boardman Project output were one and the same as outlined in Exhibit C of Contract No. DE-MS79-86BP92300. *Id*. The payment provisions of the contract establish that each individual utility owner of the 10 percent share of the Boardman project was treated as an individual owner of its respective share of the project, and each individually assumed the responsibility for payment of its share of Boardman's operations as it related to Contract No. DE-MS79-86BP92300. *Id*.

Exhibit C of Staff's 7(b)(2) rebuttal testimony is a June 17, 2008, email from Tyran Gardner, an administrative assistant at PNGC Power, to Jeremy Hyde of BPA, which established the list of PRC members at that time. *Id*. The membership of PRC as of June 17, 2008, consisted of the same membership list contained in Exhibit C of Contract No. DE-MS79-86BP92300, with the exception that Lincoln Electric Cooperative, Inc's 2.74 percent interest in the 10 percent interest of PNGC succeeded by PRC's interest in the Boardman Project had been acquired by West Oregon Electric Cooperative, Inc. *Id*. All of these owners of PRC's 10-percent interest in the Boardman Project are consumer-owned utilities that have current section 5(b) power sales contracts with BPA. *Id*.

Staff's position, which is the same position adopted by PNGC and its member utilities at the time Contract No. DE-MS79-86BP92300 was signed, is that PRC's interests in the Boardman Project have been purchased and/or assigned to PRC's membership as outlined in Exhibit C to Contract No. DE-MS79-86BP92300. *Id*. at 40-41. PRC prepares annual operating budgets concerning the operation of the Boardman power plant that assign each of its members the economic interest and responsibility for Boardman's operations based on PGE's annual operating budgets for the plant, which can be found in the Section 7(b)(2) Rate Test Study, WP-10-E-BPA-06, Exhibit C, at C-29 through C-34, plus the costs of PRC's operations. *Id*. at 41. The operation of PRC is analogous to that of a partnership where each member receives the benefits and has the responsibility for its respective ownership share of the costs of operations related to the Boardman Coal Plant. *Id*.

Staff notes the IOUs' argument that "PRC is not a public body or cooperative" and that BPA itself determined the original PNGC was not a public body or a cooperative. *Id*. The IOUs state that because PNGC became PRC, PRC, like PNGC, is neither a public body nor a cooperative. *Id*. Thus, the IOUs claim, the output from PRC's interest in the Boardman project is not "owned or purchased by a public body or a cooperative." *Id*. BPA does not agree with the IOUs' argument. *Id*. In response, however, BPA's determination that PNGC was not a public body or cooperative did not occur, and did not address, *PRC's* members and structure or address the context of resource acquisitions by such public body and cooperative members. Staff's testimony establishes that the membership of PRC and the 13 consumer-owned utilities that own 100 percent of PRC's interest in the Boardman Coal Plant are one and the same. *Id*.

The IOUs argue that even if PRC is a "public body" or "cooperative" or that the output from PRC's 10-percent interest in the Boardman Coal Plant is previously owned by PRC's 13 consumer-owned utility members, that provides no basis for including the resource in the section 7(b)(2)(D) resource stack. IOU Br., WP-10-B-JP1-01, at 16-22. The IOUs claim the resource has been sold to Turlock and, therefore, can no longer be considered "owned or purchased by public bodies or cooperatives." *Id*. The IOUs note BPA continues to assert that a public body "owns" a resource even after it sells that output to another entity—in this case, Turlock. *Id*. at 18, *quoting* WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 559-560. The IOUs claim the intent of section 7(b)(2) in this regard is clear: only resources that can be called on during the Five-Year Period to meet the general requirements of preference customers during that period, either 1) because the Administrator has actually purchased such resources from public bodies or cooperatives or 2) because such resources are otherwise available to meet the general requirements of preference customers *(i.e.*, owned by a preference customer and not committed to load), are properly includable in the section 7(b)(2)(D) resource stack. *Id*. The IOUs fail to recognize, however, that the Boardman resource satisfies the second standard. Boardman is owned by preference customers and is not committed to load pursuant to section 5(b) of the Act. Resources owned (or purchased) by a public body or cooperative customer that have not been committed to load pursuant to section 5(b), but where the output has been sold outside the region, are properly included in the section 7(b)(2)(D) resource stack. Such public body- or cooperative-owned resources not dedicated to load are available to meet remaining general requirements *in the 7(b)(2) Case* because in that alternative reality such customers would have used them to meet their loads instead of making the sale to another party.

The IOUs state that the fact that a resource may be included in the section 7(b)(2)(D) resource stack even after it is purchased from a public body or cooperative by the Administrator does not, as BPA asserts, mean that a preference customer continues to "own" the resource after it has sold the resource to a non-preference customer entity. IOU Br., WP-10-B-JP1-01, at 16-22. In response, however, the "resource" itself has *not* been purchased from the public body or cooperative. Instead, the public body or cooperative retains ownership of the resource but sells a portion or all of the "output" to another party. This is clearly demonstrated by the fact that PRC and its member utilities remain responsible for making payments to PGE for their share of Boardman expenses. The 7(b)(2) Case assumes the public body or cooperative would not have sold the output to another party, but rather, because it owned the resource and controlled whether to sell the resource or not, would have used the power to meet its own loads. The purpose of the section 7(b)(2)(D) resource stack is to meet the loads of 7(b)(2) Customers when the Federal base system is insufficient to meet such loads. Because BPA would not have resource acquisition authority absent the Northwest Power Act in the 7(b)(2) Case, 7(b)(2) Customers would be responsible for meeting their own loads when the Federal base system resources is inadequate to meet such loads. It is assumed in the 7(b)(2) Case that different contractual relationships would need to exist because 7(b)(2) Customers cannot be assured that BPA will meet all of their general requirements. Therefore, in the 7(b)(2) Case, resources owned or purchased by 7(b)(2) Customers but not committed to load are available to such customers.

Staff addresses the IOUs' argument that the "resource" is the "output" from PRC's interest in the Boardman Coal Plant, not the physical generating facilities and that PRC has sold the output from its interest in the Boardman Coal Plant to Turlock Irrigation District. Doubleday *et al*., WP-10-E-BPA-39, at 41-42. Staff notes BPA has previously stated its position that non-dedicated resources should be included in the section 7(b)(2)(D) resource stack if the owner(s) of the economic interest to the resource sells the power output from the resource to another party outside the region. *Id*. at 42, *citing* WP-07 Supplemental ROD (Conformed), WP-07-A-05, Chapter 16.10, at 546-596. BPA presented a thorough discussion of its response and legal analysis to the IOUs' argument. *Id*. The complete record of the WP-07 Supplemental rate proceeding has been adopted as part of the record of this proceeding and is hereby incorporated as part of this analysis. *Id*.

The WP-07 Supplemental ROD captures the inherent problem with the IOUs' argument:

> Holding to the IOUs' interpretation, in addition to being in conflict with section 7(b)(2)(D)(i), would restrict eligible resources under section 7(b)(2)(D)(ii) to those resources owned by preference customers that are otherwise idle resources; that is, resources not used to meet preference customer load and not sold to any other entity. This is an extremely limiting interpretation of section 7(b)(2)(D)(ii). Resources are not usually built and then left idle. If there is any economic value in the resource, the owner would attempt to sell power to capture the economic value. Thus, the only resources that would be available under the IOUs' interpretation would be very expensive, noneconomic resources. Further, the IOUs' interpretation would exclude resources exported from the region under the reading that the extra-regional purchaser now "owns" the resource. Given the concern in section 9(c) about resources being sold outside of the region, it is unreasonable to believe that Congress would place hurdles in the

way of the export of 5(b) resources and allow a loophole through section 7(b)(2)(D).

WP-07 Supplemental ROD (Conformed), WP-07-A-05, Chapter 16.10, at 560.

Further support for including the Boardman Coal Plant in the section 7(b)(2)(D) resource stack can be found in the Implementation Methodology. *Id., citing* Study, WP-10-E-BPA-06, Attachment 2, at 8: "These additional resources are defined in section 7(b)(2)(D) … (b) existing 7(b)(2) Customer resources not currently committed to regional load by preference customers or IOUs…." Boardman is not committed to regional load by preference customers.

In conclusion: 1) PRC's 10-percent ownership of the Boardman Coal Plant is owned by 13 consumer-owned utilities that currently have and are projected to have section 5(b) power purchase contracts with BPA through the rate test period; 2) these 13 utilities have not committed their share of Boardman to their loads pursuant to section 5(b) of the Northwest Power Act and, along with PRC, have sold their 10-percent portion of the Boardman Coal Plant outside of the region to the Turlock Irrigation District in California; and 3) because of points 1 and 2, the Boardman Coal Plant resource is properly includable in the section 7(b)(2)(D) resource stack.

The IOUs argue that to the extent BPA continues to insist on including resources in the 7(b)(2)(D) resource stack that are sold by the preference customers and not available to serve their general requirements, such as the output from PRC's interest in the Boardman Coal Plant, such resources should, at a minimum, be included at the market price. IOU Br., WP-10-B-JP1-01, at 16-22. The IOUs state that the purpose of the section 7(b)(2) rate test is to compare the cost of serving the general requirements in the Program Case with the cost of serving the general requirements in the 7(b)(2) Case. *Id.* The IOUs claim that BPA's methodology of including in the section 7(b)(2)(D) resource stack resources sold by preference customers (but not acquired by BPA) at the preference customers' original costs for such resources allows preference customers to unreasonably "have their cake and eat it too." *Id.*

The IOUs state that in the real world that is reflected in the Program Case, preference customers can sell their resources at market prices and use the profits to reduce their retail rates, while in the 7(b)(2) Case, BPA assumes those resources are available to meet their general requirements at their original costs. *Id.* at 21. Thus, preference customers can receive a double benefit from older resources whose costs are below the current market—once when they sell them at market rates, and again when BPA uses them in the 7(b)(2) Case to serve their general requirements—effectively increasing the section 7(b)(3) trigger amount and thereby reducing REP benefits. *Id.* The IOUs state that even assuming *arguendo* that resources no longer owned by preference customers and not acquired by BPA are included in the section 7(b)(2)(D) resource stack, there is no basis for including those resources at the cost thereof to the preference customers and ignoring their profits from the sale. *Id.* The IOUs state that if the output from PRC's interest in the Boardman Coal Plant is included in the section 7(b)(2)(D) resource stack, it should be included at market price. *Id.* The IOUs argue that, at a minimum, the output from PRC's interest in the Boardman Coal Plant should be included at the price that PRC receives from Turlock for such output. *Id.* at 22. The cost to PRC if the Boardman Coal Plant output is used to serve preference agency general requirements would be the revenue that PRC would not receive from the sale to Turlock. *Id*. At such cost, PRC would be economically indifferent as to whether the output was used to serve the preference customers' general requirements or was sent to Turlock. *Id*. The IOUs state that when BPA acquires from a preference customer a resource that is included in the section 7(b)(2)(D) resource stack (Type 1 resource), BPA includes such resource at BPA's cost of acquisition, not at the cost for the resource incurred by the selling preference customer. *Id*. A parallel treatment for a Type 2 resource that has been sold long term would be to include it in the section 7(b)(2)(D) resource stack at the actual sale price—in this case, the price that PRC receives from Turlock for that resource. *Id*.

BPA previously addressed this issue in the WP-07 Supplemental ROD. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 577. Section 7(b)(2) prescribes the preference customer resources that are assumed to be used to meet preference requirements in the 7(b)(2) Case. *Id*. It does not matter whether such resources might have been sold in a non-7(b)(2) Case world in a different manner. *Id*. Furthermore, assuming power sales made by preference customers were made at cost is a reasonable assumption in the context of section 7(b)(2). *Id*. This places such resources in the section 7(b)(2)(D) resource stack on the same footing as the FBS resources in the 7(b)(2) Case and the Program Case, which are also included at cost. *Id*. The complete record of the WP-07 Supplemental proceeding has been adopted as part of the record of this proceeding and is hereby incorporated as part of this analysis. The consumer-owned utilities' ownership of PRC's 10 percent portion of the Boardman Coal Plant is correctly included at cost as reflected in PGE's operating budgets and other information available from PGE. *Id*.

In their Brief on Exceptions, the IOUs note that their Initial Brief argued that only resources that can be called on during the Five-Year Period to meet the general requirements of preference customers during that period, either 1) because the Administrator has actually purchased such resources from public bodies or cooperatives or 2) because such resources are otherwise available to meet the general requirements of preference customers (*i.e.*, are owned by a preference customer and not committed to load), are properly includable in the section 7(b)(2)(D) resource stack. IOU Br. Ex., WP-10-R-JP1-01, at 12. The IOUs state that BPA erroneously rejects this interpretation of section 7(b)(2)(D) based on the argument that limiting resources owned by preference customers to those available during the Five-Year Period to meet the general requirements of preference customers would be an extremely limiting interpretation that would result in there being very few Type 2 resources. *Id*. at 13.

First, the IOUs have paraphrased the provisions of section 7(b)(2)(D) of the Northwest Power Act. In pertinent part, Section 7(b)(2)(D) states that

> all resources that would have been required, during such five-year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were—purchased from such customers by the Administrator pursuant to section 839d of this title, or not committed to load pursuant to section 839c(b) of this title, and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator….

16 U.S.C. § 839e(b)(2)(D). Contrary to the IOUs' claims, BPA has not rejected the correct interpretation of this language. BPA's interpretation of this language is set forth in the Legal Interpretation. Study, WP-10-FS-BPA-06, Attachment 1, at 16-17.

Second, BPA's objection to the IOUs' interpretation is not simply that it would result in a small number of Type 2 resources. It is the limitation on the disposition of resources that would be included in this category that renders the IOUs' interpretation suspect. As noted previously, the IOUs' interpretation, in addition to being in conflict with section 7(b)(2)(D)(i), would restrict eligible resources under section 7(b)(2)(D)(ii) to only those resources owned by preference customers that are otherwise idle resources; that is, resources not used to meet preference customer load and not sold to any other entity. Resources are not usually built and then left idle. If there is any economic value in the resource, the owner would attempt to sell power to capture the economic value. Thus, the only resources that would be available under the IOUs'interpretation would be very expensive, noneconomic resources. This makes little sense.

The IOUs argue there is no requirement in the Northwest Power Act that there be any Type 2 resources—and certainly no requirement that there be more than a limited number. IOU Br. Ex., WP-10-R-JP1-01, at 14. The IOUs assert that when the Northwest Power Act was adopted, it was contemplated that BPA could serve the future load growth of preference customers and, if BPA did so, it would acquire all, or virtually all, of the resources needed to serve preference agency load growth (and there would be no or virtually no Type 2 resources). *Id.* The IOUs cite the legislative history of the Northwest Power Act, noting that the Administrator has the authority to acquire resources to meet future net requirements of relevant customers, thereby ensuring the ability to meet their future needs. *Id. citing* H.R. Rep. No. 96-976, Part I, 96th Cong., 2d Sess. 28 (1980).

This argument proves little. Just as the Administrator has the authority to acquire resources to meet requirements loads, requirements utilities have the right (subject to the conditions of the Act) to commit or not commit certain resources to meet their requirements. This is why section 7(b)(2) recognizes that the section 7(b)(2)(D) resource stack includes resources owned or purchased by public bodies and cooperatives but not committed to serving regional utilities' requirements. Logic suggests there may be any number of reasons why a utility would choose not to commit a resource to its requirements; for example, in order to sell the output of the resource in the market. Logic also establishes that preference customers would not own or purchase resources but then fail to use them to meet preference customer load and fail to sell them to any other entity, thereby rendering them idle or useless. Furthermore, the IOUs' logic that BPA rejects their argument because it would limit the number of resources in the section 7(b)(2)(D) resource stack is belied by the fact that BPA includes just one such resource—Boardman. It is not the limitation of quantity resulting from the IOU position that BPA rejects, but the limitation of quality—idle resources.

The IOUs claim that the quotation they cite from the Draft ROD contains an erroneous assertion that the interpretation of section 7(b)(2)(D) advanced in their Initial Brief would somehow create a "loophole" for export of section 5(b) resources. IOU Br. Ex., WP-10-R-JP1-01, at 14, *citing* Draft ROD, WP-10-A-01, at 140. The IOUs argue that, to the contrary, the interpretation of section 7(b)(2)(D) advanced in their Initial Brief—to exclude from the section 7(b)(2)(D) resource stack those resources that preference agencies no longer own and that are not acquired by BPA—would thereby prevent the preference customers from benefiting both by selling the output of a resource outside the region and still having that output treated as available for the section 7(b)(2)(D) resource stack. IOU Br. Ex., WP-10-R-JP1-01, at 14-15. The IOUs assert that the interpretation of section 7(b)(2)(D) advanced in their Initial Brief cannot be considered a "loophole" that in any way encourages the export of resources owned by preference agencies. *Id*. at 15.

The IOUs' argument is not persuasive. The first flaw in the IOUs' argument is that it incorrectly assumes that when the output of a resource is sold, it cannot be available for the section 7(b)(2)(D) resource stack in the 7(b)(2) Case. The 7(b)(2) Case of the rate test posits a world where BPA has insufficient resources to meet preference customer requirements, and preference customers' own resources (and certain other utility resources) must be used to meet their remaining requirements. For example, the resources BPA purchased from preference customers in the Program Case are assumed in the 7(b)(2) Case to be available to meet preference customers' remaining requirements. 16 U.S.C. § 839e(b)(2)(D)(i). This is so despite the fact that the resources had been sold—to BPA. Similarly, utility resources not committed to serving load under section 5(b) of the Northwest Power Act are used in the 7(b)(2) Case to meet preference customers' remaining requirements. 16 U.S.C. § 839e(b)(2)(D)(i). Resources not committed to load logically would be sold and not simply left unused if not dedicated. These provisions are consistent with the concept of assuming in the 7(b)(2) Case that preference customers would retain resources to meet their requirements in the absence of BPA's ability to meet such requirements—whether sold to BPA or out of the region in the Program Case. In the 7(b)(2) Case, preference customers would not sell their resources outside the region, and thereby encourage the sale of regional resources outside of the region, when their resources are needed to meet their remaining requirements. This is particularly true where the Regional Preference Act already places constraints on the sale of regional resources outside the region. 16 U.S.C. § 837. Furthermore, section 7(b)(2) does not require BPA to assume that a utility's physical resource has been sold outside the region and therefore the regional utility has no rights whatsoever to determine the disposition of power produced by the resource. Instead, the resource's output has been sold, but the ultimate rights regarding what is done with the power reside with the resource owner. This is why it is reasonable to assume in the 7(b)(2) Case, where preference customers' resources are used to meet remaining requirements, that an extraregional sale would not have been made in order that a preference customer could meet its remaining requirements. The IOUs' interpretation would allow a preference customer to sell power outside the region in the 7(b)(2) Case even though it needed that power to meet its general requirements. This makes little sense.

This view of section 7(b)(2)(D)(ii) is consistent with section 7(b)(2)(D)(i), where the sale to BPA would not have been made either. In the 7(b)(2) Case, neither sale would have occurred, allowing the least expensive of all such resources to be used *by the 7(b)(2) Customers* to meet their general requirements that BPA is unable to meet after the FBS has been exhausted. It is evident that the resources sold to BPA are not being used *by BPA* to serve the remaining general requirements in the 7(b)(2) Case because the "least expensive resources owned or purchased by public bodies or cooperatives" is not how BPA is instructed to recover the costs of resources it sells. Section 7(b)(1) contains no such stacking of resource cost when BPA is determining the Program Case rates for preference (and exchange) customers.

Decision

BPA has properly included the output from Power Resources Cooperative's 10 percent share of the Boardman Coal Plant in the section 7(b)(2)(D) resource stack at the cost of the resource.

10.5 DSI Reserves

Issue 1

Whether BPA should make an estimate at this time in the 7(b)(2) and Program Case calculations of a difference between the value of and credit for DSI reserves until there is contract assurance from the DSIs regarding reserves.

Parties' Positions

APAC argues that BPA should make no estimate at this time in the 7(b)(2) and Program Case calculations of a difference between value and credit until there is contract assurance from the DSIs regarding reserves. APAC Br., WP-10-B-AP-01, at 14.

The IOUs argue that BPA must in this proceeding make a reasonable projection of the value of the reserves to be provided by DSIs during FY 2010-2011 and the balance of the Five-Year Period and reflect that projection in the section 7(b)(2) rate test. IOU Br., WP-10-B-JP1-01, at 84.

BPA Staff's Position

BPA Staff believes the 7(b)(2) Case revenue requirement should include the costs of reserves that are provided by the DSI contracts in the Program Case but not available in the 7(b)(2) Case. Doubleday *et al*., WP-10-E-BPA-39, at 45.

Evaluation of Positions

APAC states that the calculation of rates requires BPA to assess three separate factors in calculating the value of DSI reserves used in the 7(b)(2) rate test: 1) the amount of reserves available and the conditions for their use; 2) the value of those reserves; and 3) the credit provided to the DSIs for the reserves. APAC Br., WP-10-B-AP-01, at 13. APAC argues that until a contract with the DSIs is negotiated, these values for DSI reserves are uncertain. *Id*., *citing* Cross Ex. Tr. at 19-20. Assumptions about the values and conditions for use have an obvious and direct impact on both the 7(b)(2) and Program Cases. *Id*. BPA must be conservative in setting those values based on the current status of DSI contracts; otherwise, preference customers may be required to pay a PF rate that is inappropriately high given the value of DSI reserves created in any ultimate contract. *Id*. Given that there is no certainty regarding the contracts, the amount of reserves and their value should be set very low. *Id*.

APAC argues BPA should not adopt the IOUs' proposal for a credit for reserves for which it has no estimate of value or willingness of DSIs to accept less than value. *Id.* That is, BPA should make no estimate at this time in the 7(b)(2) and Program Case calculations of a difference between value and credit until there is contract assurance from the DSIs regarding reserves. *Id.*

APAC's underlying argument is addressed in section 14.8. For purposes of the section 7(b)(2) rate test, BPA will base the 7(b)(2) Case value of reserves on the type and amount of reserves used to establish the IP rate in the Program Case.

The IOUs argue that BPA must assume that quantifiable monetary savings from reserve benefits were not achieved in the 7(b)(2) Case. IOU Br., WP-10-B-JP1-01, at 83. In connection with discussion of additional reserves that may be provided by DSIs, the Staff rebuttal testimony states as follows:

> The value [of certain DSI reserves that might be provided] could be assigned as a reduction in the energy rate for a BPA power sale to a DSI; or if individual DSI contracts provide for such service, a credit could be computed and assigned pursuant to contract terms.

Id., *citing* Fisher *et al.*, WP-10-E-BPA-36, at 22. Staff indicated during cross-examination that they intended this statement to describe different ways in which DSI reserves might, in Staff's view, be treated but that Staff was not trying to speculate as to which way might be adopted:

> Q. And you're saying that that value could be assigned as a reduction in the energy rate for a BPA power sale to a DSI, or if an individual DSI contract provides for such service, a credit could be computed and assigned pursuant to contract terms. Now, I'm trying to understand that statement in the context of the -- sort of the statutory construct for the IP rate, if you will.
>
> Does that sentence that I just paraphrased from your testimony mean that BPA is contemplating obtaining reserves or a similar product from DSIs but not reflecting the value, be it 50 percent of that value or some other portion, in the Northwest Power Act Section 7(c)(3) IP rate adjustment?
>
> A. (Mr. Fisher) No. We weren't trying to propose a method for implementing this. We were just saying that you could do it in possibly different ways but not trying to speculate on which way we would do it when the time came.

IOU Br., WP-10-B-JP1-01, at 83, *citing* Cross Ex. Tr. at 105. Staff's assertion regarding different ways in which reserves might be treated or labeled cannot and should not obscure the fact that DSI reserves—however labeled—must be recognized as reserves in each BPA rate case, including, in particular, the determination of the IP rate under section 7(c)(3) of the Northwest Power Act (in which the DSIs should receive 50 percent of the value of reserves under the "Share-the-Savings" approach) and the evaluation of reserves under section 7(b)(2) of the Northwest Power Act. IOU Br., WP-10-B-JP1-01, at 84. In addition, actual interruption rights that are eventually agreed upon must be reflected in the determination of DSI reserves in future rate cases. *Id.*

The IOUs argue, in short, that BPA must in this proceeding make a reasonable projection of the value of the reserves to be provided by DSIs (which projection cannot be unreasonably low—that would be arbitrary and capricious) during FY 2010-2011 and the balance of the Five-Year Period, reflect that projection in the section 7(b)(2) rate test, and assign 50 percent of the value of reserves to the DSIs. *Id*.

BPA agrees with the portion of the IOUs' argument dealing with whether the 7(b)(2) Case revenue requirement should include the costs of reserves that are provided by the DSI contracts in the Program Case but not available in the 7(b)(2) Case. Doubleday *et al*., WP-10-E-BPA-39, at 45. In the Initial Proposal, the 7(b)(2) Case revenue requirement was increased by Staff's estimate of the value of reserves provided by the assumed DSI contracts. *Id*. Because no sales contracts to the DSIs existed at the time of the Initial Proposal, Staff made its best effort to estimate the value of reserves that a likely set of DSI contracts would provide. *Id*. At this later date, Staff is recalculating its estimate of the value of reserves, and that more-current estimate will inform the additions to the 7(b)(2) Case revenue requirement. *Id*., *citing* Fisher *et al.*, WP-10-E-BPA-36.

Staff's actions are supported by the Northwest Power Act. Section 5(d)(1)(A) of the Act provides that "[s]uch [DSI] sales *shall* provide a portion of the Administrator's reserves for firm power loads within the region." 16 U.S.C. § 839c(d)(1)(A) (emphasis added). Also, section 7(c)(3) of the Act states that "[t]he Administrator *shall* adjust such [DSI] rates to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers." 16 U.S.C. § 839e(b)(3) (emphasis added). The word "shall" is mandatory. If BPA assumes it will make power sales to the DSIs, then reserves must be provided. If reserves must be provided, then the IP rate must be adjusted. If the IP rate is adjusted, the 7(b)(2) Case must take such value of reserves into account in the power costs used to develop the 7(b)(2) Case rate.

<u>Decision</u>

BPA will make an estimate for the value of, and credit for, DSI reserves to inform the 7(b)(2) rate test.

<u>Issue 2</u>

Whether any BPA decision to provide DSI benefits through monetary payments to DSIs (or through monetary payments or power sales through the local utility) should reduce the level of REP benefits provided by BPA.

<u>Parties' Positions</u>

The IOUs argue if and to the extent that BPA were to decide to provide DSI benefits through monetary payments to DSIs (or through monetary payments or power sales through the local utility), that decision should not reduce the level of REP benefits provided by BPA. IOU Br., WP-10-B-JP1-01, at 84-85.

BPA Staff's Position

BPA Staff believes the effect of any BPA decision to provide DSI benefits through monetary payments to DSIs, or through monetary payments or power sales through the local utility, does not require specific criteria, but should be determined through normal BPA ratemaking. Doubleday *et al*., WP-10-E-BPA-39, at 46.

Evaluation of Positions

The IOUs argue if and to the extent that BPA were to decide to provide DSI benefits through monetary payments to DSIs (or through monetary payments or power sales through the local utility), that decision should not reduce the level of REP benefits provided by BPA. IOU Br., WP-10-B-JP1-01, at 84-85. The IOUs note BPA stated in the DSI ROD that in order to provide DSI benefits through monetary payments to DSIs, BPA would need to "be assured that the cost impact on other customers was 'roughly no greater than if BPA had exercised its discretion to serve the DSI customers' directly with physical power deliveries using the IP rate." *Id*.

The IOUs argue that if BPA were to decide to provide DSI benefits by a mechanism other than direct physical power deliveries by BPA under the IP rate (*e.g.*, as monetary payments), such a decision would have a substantial effect on the PF Exchange rate unless BPA includes the DSI service benefits in the 7(b)(2) Case. *Id*. The IOUs assert that both fundamental fairness and BPA's stated criterion—cost impact on other customers roughly no greater than a DSI power sale under the IP rate—require that BPA avoid imposing, in effect, virtually the entire cost of DSI benefits on the PF Exchange rate. *Id*. The IOUs claim that imposing virtually the entire cost on the PF Exchange rate would be arbitrary, unjustified, unfair, and unnecessary. *Id*.

The IOUs state that if BPA were to decide to provide DSI benefits by a mechanism other than direct physical power deliveries by BPA under the IP rate, either 1) the costs of the DSI-service-benefit monetary payments should be included in the 7(b)(2) Case costs or 2) the power equivalent of the DSI benefits should be included as load in the general requirements of the PF Preference rate customers in the 7(b)(2) Case. *Id*.

In the Initial Proposal, Staff included the forecast DSI load in the Program Case and in preference loads in the 7(b)(2) Case. Doubleday *et al*., WP-10-E-BPA-15, at 25. However, Staff does not agree with the IOUs' proposed criteria that power service to the DSIs or monetary benefits to the DSIs can have no effect on the REP benefits provided by BPA. Doubleday *et al*., WP-10-E-BPA-39, at 46. The IOU criteria are not based upon any of BPA's rate directives. *Id*. Staff stated BPA will include the proper amount of load and/or monetary benefit costs in both the Program Case and the 7(b)(2) Case, and the effect on the level of REP benefits will be an outcome of normal BPA ratemaking. *Id*. No special criteria are called for, and none will be used. *Id*. However, a test of the rate modeling showed the difference in rates and REP benefits when comparing comparable levels of power sales and monetary benefits (*i.e.*, when the net cost of DSI power sales equals the monetary benefit) is in the realm of "model noise." *Id*. Based on this one test, the result the IOUs are concerned about may not be an issue. *Id*. In the Final Proposal, BPA includes the proper amount of load in both the Program Case and the 7(b)(2) Case to establish the level of REP benefits.

Decision

The effect of any BPA decision to provide DSI benefits through monetary payments to DSIs, or through monetary payments or power sales through the local utility, will be determined through normal BPA ratemaking. In any event, the IOUs' concern is moot. In the Final Proposal, BPA assumes that the DSIs will be served through a sale of power, not monetized benefits. REP benefit levels are determined when rates are established. Should BPA later decide to monetize the benefits to DSIs, it will not affect the level of REP benefits.

10.6 Calculation of the Rate Test Trigger

Issue 1

Whether BPA's methodology to perform the present value calculation and averaging in the 7(b)(2) rate test distorts rate test results in future years.

Parties' Positions

APAC argues the methodology BPA uses to perform the present value calculation and the averaging in the 7(b)(2) rate test distorts the rate test results in future years. APAC Br., WP-10-B-AP-01, at 13. APAC further argues that the trigger calculation should be based on an inflation adjustment internal to the data for BPA costs and ASC levels. *Id*.; APAC Br. Ex., WP-10-R-AP-01, at 8. APAC claims this methodology better smoothes the annual trigger data while minimizing the difference between the annual values and the combined trigger. *Id*.

The IOUs argue that the variations in the annual trigger results are not anomalies for which adjustments need to be made to the 7(b)(2) rate test. IOU Br., WP-10-B-JP1-01, at 29. The IOUs state that BPA's current method of discounting to arrive at a section 7(b)(3) trigger amount does not distort the results. *Id*. at 32.

The OPUC argues that APAC does not compare the root mean square deviations for the three methods, but compares the root square deviations, which leads to an overstatement of the difference between results obtained under the current Implementation Methodology and APAC's recommended methodologies. OPUC Br., WP-10-B-PU-01, at 9. OPUC also believes APAC's analysis makes an apples-to-oranges comparison; that the benchmark used by APAC's simulation model to calculate "error" (deviation) is not adjusted for the time value of money but is just the difference between the unbifurcated PF rate and the 7(b)(2) Case rate; and APAC's simulation model introduces a "chicken and egg" problem with regard to the "Internal Inflation Method." *Id*. at 10.

BPA Staff's Position

BPA Staff does not believe BPA's methodology to perform the present value calculation and averaging in the 7(b)(2) rate test distorts rate test results in future years. Doubleday *et al*., WP-10-E-BPA-39, at 50. Staff believes the statutory directive to include four years beyond the rate period is to ensure that the rate period 7(b)(2) rate test trigger in one rate case is similar to the rate test triggers in later rate cases, all else being equal. *Id*. This is accomplished by reducing the weighting of an anomalous first-year rate difference between the Program Case and the 7(b)(2) Case. *Id*. Also, smoothing the within-rate-case annual data is not necessarily a meaningful criterion; nor is minimizing the differences between the rate test period average difference and the annual differences between the Program Case and 7(b)(2) Case rates. *Id*. at 51.

Evaluation of Positions

APAC notes that the calculation of the trigger amount under the 7(b)(2) rate test requires BPA to calculate the rates for the Program Case and the 7(b)(2) Case for the rate period and for four ensuing years. APAC Br., WP-10-B-AP-01, at 13. APAC states that, although not specified by the statute, BPA discounts each of these rates to a present value using BPA's borrowing rate and then averages them. *Id*. APAC argues that the methodology BPA uses to perform the present value calculation and the averaging distorts the rate test results in future years. *Id*. APAC believes the trigger calculation should be based on an inflation adjustment internal to the data for BPA costs and ASC levels. *Id*.; APAC Br. Ex., WP-10-R-AP-01, at 8. APAC claims this methodology better smoothes the annual trigger data while minimizing the difference between the annual values and the combined trigger. *Id*.

The IOUs disagree with APAC, stating that variations by year in the difference between the nominal Program Case rate and the nominal 7(b)(2) Case rate are not "anomalies for which adjustments need to be made." IOU Br., WP-10-B-JP1-01, at 29. The IOUs note that BPA describes its comparison of Program Case rates and 7(b)(2) Case rates during the Five-Year Period as follows:

> The comparison between the Program Case and the 7(b)(2) Case rates will be conducted for the Five-Year Period and will consider the time value of money. Therefore, the two sets of rates will be discounted back to the beginning of the first year of the Relevant Rate Case at BPA's projected future nominal borrowing rate, and then a simple average will be computed over the Five-Year Period. … If the simple average of discounted 7(b)(2) Case rates is less than that of the Program Case rates, then a determination of an amount of rate protection to be reallocated in BPA's rate proposal is required.

Id., citing Section 7(b)(2) Rate Test Study, WP-10-E-BPA-06, Attachment 2, at 10. The IOUs state that BPA calculates a nominal Program Case rate and a nominal 7(b)(2) Case rate for each year in the Five-Year Period, discounts those rates, averages those discounted rates, and takes the difference between the average discounted Program Case rate and the average discounted 7(b)(2) Case rate to arrive at the section 7(b)(3) trigger amount. IOU Br., WP-10-B-JP1-01, at 29.

The IOUs note that APAC points out that the difference between the nominal Program Case rate and nominal 7(b)(2) Case rate varies by year within the Five-Year Period. *Id*. (The APAC direct testimony refers to these annual differences as "annual trigger results" or "annual trigger data".) The IOUs state the APAC direct testimony, in essence, erroneously argues that the variations in the "annual trigger results" are "anomalies for which adjustments need to be made." *Id*. The IOUs state that the fact that the difference between the nominal Program Case rate and nominal 7(b)(2) Case rate varies by year within the Five-Year Period 1) does not demonstrate that there are "anomalies for which adjustments need to be made," and 2) does not demonstrate that BPA's methodology for arriving at a section 7(b)(3) trigger amount from the projected Program Case rates and 7(b)(2) Case rates is flawed. *Id.*

The IOUs note that the nominal Program Case rates and nominal 7(b)(2) Case rates vary among years because of variations in factors such as forecast loads, resources, and costs. *Id.* Additionally, given the differences in the way in which the Program Case rates and the 7(b)(2) Case rates are determined, there is no reason to assume that factors such as forecast loads, resources, and costs will have the same effect on these two rates. *Id.* The IOUs state that variations in these factors are not "anomalies" that should be eliminated. *Id.* Indeed, the IOUs argue, BPA's calculation of the difference between the average of the discounted Program Case rates and the average of the discounted 7(b)(2) Case rates already accounts for the annual variations between the Program Case rates and the 7(b)(2) Case rates, and no adjustments need be made. *Id.*

The IOUs note that the APAC direct testimony suggests that annual section 7(b)(3) triggers should be smoothed and the difference between annual section 7(b)(3) triggers and the combined section 7(b)(3) triggers should be "minimized." *Id.* As discussed above, the fact that the difference between the nominal Program Case rate and nominal 7(b)(2) Case rate varies by year within the Five-Year Period does not demonstrate that there are "anomalies for which adjustments need to be made"; there is no need for an adjustment to 1) smooth annual section 7(b)(3) trigger amounts, or 2) "minimize" the difference between annual section 7(b)(3) trigger amounts and the combined section 7(b)(3) trigger amount. *Id.*

The IOUs also argue that BPA's current method of discounting to arrive at a section 7(b)(3) trigger amount does not "distort" the results, as APAC claims. *Id.* The IOUs state that since 1984, BPA has consistently used its projected borrowing rates to discount projected Program Case rates and 7(b)(2) Case rates in arriving at a section 7(b)(3) trigger amount. *Id.* BPA's direct testimony in its 1984 proceeding explained why BPA uses its projected borrowing rate for each year to discount projected Program Case rates and 7(b)(2) Case rates in arriving at a section 7(b)(3) trigger amount:

> Q. How will the two sets of five year rate projections actually be compared?
>
> A. We propose to discount the rates for each year of the five-year rate test periods back to the test year of the relevant rate proposal. The five discounted rates for each year will be averaged. The two averages, one for the program case and one for the 7(b)(2) case, will then be compared. If the average 7(b)(2) case rate is significantly (one-tenth of a mill or more) less than the program case rate, the section 7(b)(2) rate test will be deemed to "trigger."
>
> Q. What is the rationale behind discounting each year's rate projection back to the test year for the relevant rate case?
>
> A. Section 7(b)(2) requires that the rates for 7(b)(2) customers be compared over a five year period, but does not specify the method. It is possible that the 7(b)(2) rate could be higher than the PF power rate in one or more years of the period and lower in others. Therefore, the weighting that is applied to the rate projections for each year can significantly affect the result of the rate test. All

> five years could be weighted equally by computing a simple average of the rates over the five-year period for each case.
>
> Although this method would be simple to apply, BPA believes that the comparison of the program case and the 7(b)(2) case rate projections should consider the time value of money. That is, if the rate in the 7(b)(2) case exceeds the rate in the program case in a given year, the differential is economically less harmful to the 7(b)(2) customers the further into the future it appears due to the time value of money. Therefore, BPA proposes to discount each set of rate projections back to the relevant rate case test year for comparison. This method will also simplify the determination of the amount to be reallocated in the test year, as described below.
>
> Q. At what rate will the five-year rate projections be discounted?
>
> A. BPA proposes to discount the projected future rates at BPA's projected future borrowing rate for each particular year. BPA's borrowing rate is projected over twenty years for each BPA rate case, and so is readily available. It is logical to use BPA's borrowing rate, since BPA could theoretically borrow the money in the test year to reimburse the 7(b)(2) customers for the five-year section 7(b)(2) rate test differential. The value to BPA of money over time is thus the economically correct value for the rate differential over time.

Id. at 32-33, *citing* Melton and Armstrong, b2-84-E-BPA-02, at 34-36. The IOUs state BPA should continue its longstanding use of its projected borrowing rate for each year to discount projected Program Case rates and 7(b)(2) Case rates in arriving at a section 7(b)(3) trigger amount. IOU Br., WP-10-B-JP1-01, at 33. The IOUs state that, contrary to the erroneous assertion of the APAC direct testimony, there is no basis for concluding that BPA's current methodology of discounting to arrive at a section 7(b)(3) trigger amount "distorts the results." *Id*.

The OPUC also argues that BPA should reject APAC's recommendations for modifying the rate test trigger calculation. OPUC Br., WP-10-B-PU-01, at 9. The OPUC notes that APAC recommends changing how BPA determines the rate test trigger. *Id*. The OPUC states that APAC's recommendation is based on its findings as to which of three different methodologies produces the most accurate trigger amount of any year's raw trigger value. *Id*. APAC recommends a straight line-like method using either 1) "internal cost" inflation or 2) general U.S. inflation. *Id*. APAC presents its comparisons of results for these two methods against results for what it calls the current BPA method. APAC's witness explains the comparison as follows:

> To determine which combining method was best, I compared the "known" single-year hypothetical result to the result determined by the averaging method, computed what is called the root-mean-square error, a statistical method to examine projected data versus "known" data, and determined that the trending of internal ASC and BPA levels produced the best result.

Id., *quoting* Wolverton, WP-10-E-AP-01, at 20. The OPUC has several concerns with APAC's analysis, and based on these concerns, recommends that the Administrator reject APAC's proposed modifications. OPUC Br., WP-10-B-PU-01, at 9.

First, the OPUC states that it appears APAC did not compare the root mean square deviations for the three methods, but compared the root square deviations. *Id*. This error led to an overstatement of the difference between results obtained under the current Implementation Methodology and APAC's recommended methodologies. *Id*. A properly calculated root mean square deviation analysis appears to show very little difference between the three methodologies compared by APAC. *Id*.

Second, APAC's analysis makes an apples-to-oranges comparison. *Id*. The formula for comparing alternative methods within APAC's simulation model includes an initial benchmark set of BPA's 7(b)(2) model raw triggers. *Id*. This initial benchmark is based on data for the first five years of the analysis. *Id*. The comparison, however, resets the five-year study period for calculating the method results for each subsequent year, while restricting raw trigger results to the initial study period. *Id*. In other words, each of the raw triggers for years 1 through 5 are compared against method values calculated on their respective five-year average. *Id*. This apples-to-oranges comparison is not meaningful. *Id*.

Third, the benchmark used by the simulation model to calculate "error" (deviation) is not adjusted for the time value of money but is just the difference between the unbifurcated rate and the 7(b)(2) PF Preference rate. *Id*. As discussed in OPUC's rebuttal testimony, it is not clear that if APAC's simulation model was changed to reflect 1) BPA's actual current method; 2) a discounted benchmark for calculating deviations; and 3) the root mean square deviation, the model would demonstrate that APAC's proposed alternate inflation methods would be more "accurate" than BPA's current method. *Id*. Further, it is likely the differences between APAC's proposed alternatives and BPA's current method would be insignificant. *Id*.

Finally, APAC's simulation model introduces a "chicken and egg" problem with regard to the "Internal Inflation Method." *Id*. The simulation model holds the internal inflation trend constant (in a straight-line increase with inflation) regardless of ASCs and BPA costs. *Id*. However, the internal inflation trend should be consistent with the random simulation of ASC and BPA costs. *Id*. Further, the OPUC suspects that raw triggers do not necessarily follow a straight line, or increase with general inflation as APAC's simulation model implies. *Id*.

The purpose of the statutory requirement to calculate rate test protection by incorporating one year plus the following four years is to remove an anomalous year or years from causing the rate test to trigger highly in favor of either preference customers or exchanging utilities. Doubleday *et al*., WP-10-E-BPA-39, at 48. By calculating the 7(b)(2) rate test over the rate period plus the ensuing four years, it produces an average rate test result that may be more stable over successive rate cases than if only one rate period is used in the calculations. *Id*. An "anomalous year" would most likely be the test year rather than any of the ensuing four years. *Id*. The nature of forecasts is that the further out into the future they are made, the more the variables used in the forecast will tend to their long-term average; that is, using average water conditions and average annual cost and load growth trends for out-year forecasts is the norm, while a current exception from normal conditions will affect the near-term outlook. *Id*. Therefore, because longer-range forecasts tend to be smoother than actual conditions or shorter-range forecasts, setting the 7(b)(2) rate test trigger on a longer set of forecast Program Case and 7(b)(2) Case rates (six years in the instant rate case) will tend to smooth the rate test results of successive rate cases and provide individual rate case results closer to the longer-term trend than if only the rate period Program Case and 7(b)(2) Case rate are used (two years in the instant rate case). *Id*. at 48-49.

BPA uses an Average Present Value method to combine the annual stream of Program Case and 7(b)(2) Case rates to one rate per case before the rates are compared to calculate the rate test trigger. *Id*. at 49. BPA's forecast borrowing interest rate is used in the present value calculation. *Id*. In this way the result is a present value from BPA's and its power customers perspective; that is, by using BPA's borrowing rate, it can be assumed that just before the beginning of the FY 2010-2011 rate period, BPA would be indifferent between providing its customers the discounted rate protection now or the non-discounted rate protection later. *Id*.

APAC argued that BPA's traditional method came into question when APAC noticed that out-year average system costs affected the rate test. Wolverton, WP-10-E-AP-01, at 18. APAC claims that this result seems to be contrary to the statutory requirement that the cost of the REP be excluded from the calculation of the rate test. *Id*. BPA disagrees. First, APAC's argument that out-year ASCs should not affect the rate test is directly contrary to section 7(b)(2). Doubleday *et al*., WP-10-E-BPA-39, at 49. One of the five assumptions in section 7(b)(2) is that REP costs are excluded from the 7(b)(2) Case. *Id*. REP costs are not, however, excluded from the Program Case. *Id*. Because the 7(b)(2) rate test trigger is derived from a comparison of the Program Case rates (with REP costs) and the 7(b)(2) Case rates (without REP costs), APAC is incorrect in stating that REP costs are excluded from the rate test. *Id*. If REP costs are higher or lower in the rate period and the ensuing four years, it is expected that, all else equal, the Program Case rates will be different, and thus the rate test results will be different. *Id*. Any change in a major cost category in either the rate period years or the ensuing four years will change the test results. *Id*.

There are no statutorily required criteria to eliminate anomalies. *Id*. at 50. As discussed above, the apparent purpose of including the four additional years is to mitigate the effects of anomalies; but mitigation is not the same as elimination. *Id*. In addition, APAC's example is unrealistic in that it has the anomaly occurring in the third year of the five-year rate test period. *Id*. As noted previously, if there were to be a forecast of an anomalous year in the five-year 7(b)(2) rate test period, it is much more likely to be the first year. *Id*. BPA agrees with APAC that a simple average of the Program Case rates and the 7(b)(2) Case rates is too simplistic. *Id*. A method using the time value of money from the perspective of how BPA would value the money is the proper way to incorporate the different years' rates in the rate test. *Id*. BPA's current method of discounting to the beginning of the rate period using BPA's borrowing rate accomplishes this goal. *Id*.

APAC tested the five-year requirement by developing a simulation model that used a set of hypothetical BPA costs, unbifurcated BPA rates, and ASC levels over a nine-year period. Wolverton, WP-10-E-AP-01, at 19. BPA has no comment on APAC's simulation model other than to acknowledge that changing major cost items will produce different rates. Doubleday *et al*., WP-10-E-BPA-39, at 51. APAC states that changes in ASCs and exchange loads that determine REP costs will have an effect on the unbifurcated PF rate and thus the results of the 7(b)(2) rate test. Wolverton, WP-10-E-AP-01, at 19. APAC stated there was a statutory requirement that the cost of the REP be excluded from the calculation of the rate test. *Id*. at 18. BPA disagrees with APAC's argument that there is a requirement that rate level anomalies need to be eliminated. Doubleday *et al*., WP-10-E-BPA-39, at 50.

The criterion APAC uses to determine the correct method of combining rate test results for each year is to find the method of combining annual trigger results that smoothes the annual trigger data but at the same time minimizes the difference between the annual values and the combined trigger, as measured by least-squares statistical calculations. *Id*. at 51. As stated earlier, the statutory directive to include four years beyond the rate period years is to ensure that the rate period 7(b)(2) rate test trigger in one rate case is similar to the rate test triggers in later rate cases, all else being equal. *Id*. This is accomplished by reducing the weighting of an anomalous first-year rate difference between the Program Case and the 7(b)(2) Case. *Id*. Also, smoothing the within-rate-case annual data is not necessarily a meaningful criterion; nor is minimizing the differences between the rate test period average difference and the annual differences between the Program Case and 7(b)(2) Case rates. *Id*.

Discounting the two sets of rates by BPA's forecast borrowing rate and then averaging the resultant discounted rates to get an average present value over the rate test period from the perspective of how BPA and its power customers, would value the rate protection is a much more appropriate method. *Id*. BPA's method has the advantage of levelizing the annual rates in a way that can be tied to BPA's financial situation; that is, using BPA's borrowing interest rate for the discounting in theory makes BPA and its power customers indifferent between providing the discounted rate protection now or the non-discounted rate protection later. *Id*. at 51-52. For the reasons just stated, the Implementation Methodology's direction to adjust the Program Case and 7(b)(2) Case rates using a BPA-centric financial time-value-of-money method before the calculation of the 7(b)(2) rate test trigger is superior to any statistical-based smoothing scheme proposed by APAC. *Id*. at 52.

APAC uses its simulation model to test three methods of smoothing the five years of results, which evaluates errors caused by the averaging method and assesses the statistical impact in a search for the least deviation from annual values. Wolverton, WP-10-E-AP-01, at 21. APAC has missed the point of using the four additional years in the 7(b)(2) rate test. Doubleday *et al*., WP-10-E-BPA-39, at 52. APAC also has statistical criteria that may be mathematically interesting but have no foundation in BPA finance. *Id*. APAC's simple average example is not what BPA does or what APAC is proposing. *Id*.

APAC recommends that BPA switch to a method for calculating the trigger based on an inflation adjustment internal to the data for BPA costs and ASC levels. Wolverton, WP-10-E-AP-01, at 21. APAC's simulations do not show that BPA's current discounting method distorts the results. Doubleday *et al*., WP-10-E-BPA-39, at 52. APAC's simulations and its proposal result in higher 7(b)(2) rate test triggers. *Id*. Those higher triggers, if adopted by BPA, would result in lower rates paid by APAC's members. *Id*. However, the current methodology of using BPA's borrowing rate as the discounting factor has the advantage of being tied to BPA's financial situation, along with the advantage of having been used since the inception of the 7(b)(2) rate test. *Id*. at 52-53. APAC's number-smoothing criteria are not based on BPA's rate directives and provide no reason for BPA to change its long-standing discounting methodology. *Id*.

Decision

BPA's methodology to perform the present value calculation and averaging in the 7(b)(2) rate test does not distort rate test results in future years. In addition, APAC's number-smoothing criteria are not based on BPA's rate directives and provide no reason for BPA to change its longstanding discounting methodology.

Issue 2

Whether BPA inappropriately discounts the Program Case and 7(b)(2) Case rates for purposes of calculating the rate test trigger by using its borrowing rate from Treasury.

Parties' Positions

PPC *et al*. propose that the only adjustment BPA should make to the Program and 7(b)(2) Case rates is to use the rate of inflation to discount those rates back to beginning of the rate period for purposes of calculating the rate test trigger and rate protection. PPC *et al*. Br., WP-10-B-JP11-01, at 23-24.

The IOUs state BPA should not use the rate of inflation rather than its borrowing rate to discount the Program Case and 7(b)(2) Case rates. IOU Br., WP-10-B-JP1-01, at 33.

BPA Staff's Position

BPA Staff believes the current discounting methodology, which uses BPA's forecast borrowing rate, used to borrow funds for items that benefit power customers, is appropriate because it makes BPA and those customers indifferent to when in the rate period (plus the ensuing four years) the rate protection is paid. Doubleday *et al*., WP-10-E-BPA-39, at 53-54.

Evaluation of Positions

PPC *et al*. note that before averaging the Program Case and 7(b)(2) Case rates for the rate period plus the ensuing four years, BPA discounts the rates back to the beginning of FY 2010 to account for the time value of money. PPC *et al*. Br., WP-10-B-JP11-01, at 23. BPA uses its projected borrowing rate from the Treasury. *Id*. PPC *et al*. propose that the only adjustment BPA should make is to use the rate of inflation to discount the Program Case and 7(b)(2) Case rates back to beginning of the rate period for purposes of calculating the rate test trigger and rate protection. *Id*. PPC *et al*. argue that their proposed method is more appropriate than BPA's current approach for several reasons. *Id*. BPA's purpose for discounting based on its borrowing rate appears to be so the agency would be financially indifferent to revenues received at different times. *Id*. However, PPC *et al*. claim that BPA's criterion for choosing a discount rate such that the agency is indifferent to the revenue on a temporal basis is misplaced. *Id*. PPC *et al*. believe the entire purpose of section 7(b)(2) is to provide a protection amount to preference customers, and ultimately to their consumers that pay the cost of BPA programs. *Id*. Therefore, PPC *et al*. assert that the discount rate should not include an interest component to make BPA indifferent; it should simply place all the rates and costs in equal terms for the consumers who are ultimately bearing the costs. *Id*.

PPC *et al*. argue that BPA should simply make an adjustment for real versus nominal dollars to take into account changes in consumer prices over time, using the GDP deflator. PPC *et al*. Br., WP-10-B-JP11-01, at 23. PPC *et al*. claim that adjusting the Program Case and 7(b)(2) Case rates using a rate greater than inflation has the effect of systematically devaluing differences in costs in the later years of the rate test period relative to the earlier years. *Id*. at 23-24. PPC *et al*. assert that the language of section 7(b)(2) directs a comparison of average power costs over a five-year period under the five assumptions. *Id*. at 24. PPC *et al*. claim that nowhere does it state that the costs from certain years should be weighted more heavily. *Id*. Therefore, in averaging the 7(b)(2) and Program Case rates, PPC *et al*. believe BPA should, at most, make an adjustment for differences in the value of money due to inflation. *Id*. PPC *et al*. allege that any other interpretation would go against the language of section 7(b)(2) of the Northwest Power Act and, in the present case, result in preference customers and their consumers not receiving the full value of their statutorily mandated rate protection. *Id*.

The IOUs disagree with PPC *et al*. The IOUs state that BPA should not use the rate of inflation rather than its borrowing rate to discount the Program Case and 7(b)(2) Case rates. IOU Br., WP-10-B-JP1-01, at 33. The IOUs believe BPA should continue its longstanding use of its projected borrowing rate for each year to discount projected Program Case rates and 7(b)(2) Case rates. *Id*. The absence of a systematic bias in the projections provides no basis for use of inflation rates rather than BPA's borrowing rates. *Id*. The use of BPA's borrowing rates to discount projected Program Case and 7(b)(2) Case rates properly reflects the time value of money in BPA's section 7(b)(2) analysis. *Id*.

The IOUs state that if BPA abandons its longstanding use of its projected borrowing rates to discount projected Program Case rates and 7(b)(2) Case rates for each year in arriving at a section 7(b)(3) trigger amount, then BPA should use the BPA Power Services discount rate to discount projected Program Case rates and 7(b)(2) Case rates for each year in arriving at a section 7(b)(3) trigger amount. *Id*. The IOUs note that the BPA Definitions posted on the BPA Web site define the term "discount rate" as follows:

> An interest rate that reflects the value of money over time. In comparing alternatives for a decision, a discount rate is applied to make different monetary stream flows equivalent, in terms of a present value or a levelized value.

Id. The IOUs note that in Response to Data Request No. AC-BPA-03, BPA stated that its BPA Power Services discount rate was 12 percent: "BPA uses a discount rate of 12 percent in evaluating Power Services capital investments for the purposes of providing a comparative ranking of projects." *Id*.

The IOUs note that BPA has not limited the use of the BPA Power Services discount rate to providing a comparative ranking of projects. *Id*. Rather, BPA has used the BPA Power Services discount rate to perform a rates analysis under two alternative sets of ratemaking assumptions. *Id*. Specifically, in a BPA presentation released January 23, 2007, and entitled "Debt Optimization Annual Meeting as Required Under the Slice Memorandum of Understanding," BPA used not only a weighted average interest (WAI) rate on Treasury Bonds but also the Power Services and Transmission Services discount rates (in that case, 13 percent for Power and

9 percent for Transmission) to analyze the rate impacts of the BPA Debt Optimization Program (DOP) and to demonstrate that "'rates of each of BPA's business lines [Transmission and Power] are no higher with the DOP than they would have been in the absence of the DOP.'" *Id*.

The IOUs state, in other words, that BPA's DOP analysis in effect compared BPA rates with and without the DOP, and BPA used both a WAI and the Power Services discount rate (or Transmission Services discount rate, as applicable) in making such comparison. The section 7(b)(2) rate test—like this DOP analysis—analyzes the rate impacts of two alternative sets of ratemaking assumptions. *Id*.

The IOUs thus argue that if BPA abandons its longstanding use of its projected borrowing rates to discount projected Program Case rates and 7(b)(2) Case rates for each year in arriving at a section 7(b)(3) trigger amount, then BPA should use the BPA Power Services discount rate to discount projected Program Case rates and 7(b)(2) Case rates in arriving at a section 7(b)(3) trigger amount—just as BPA used the Power Services discount rate in its DOP analysis. *Id*.

BPA disagrees with PPC *et al.* PPC *et al*. apparently do not argue against BPA using a time value of money discounting methodology. Doubleday, *et al*., WP-10-E-BPA-39, at 53. However, PPC *et al*. have confused the concepts of the "time value of money" and "real versus nominal dollars." *Id*. The concept of the time value of money is based on the fact that money available at the present time is worth more than the same amount in the future. *Id*. The difference is due to the potential earning capacity of an amount of money in hand today as compared to the same amount of money available at some future date. *Id*. Therefore, any amount of money that could earn an interest rate is worth more the sooner it is received. *Id*. For example, assuming that a 6.75 percent average BPA borrowing rate is the interest rate in question, $100 invested today would be worth $106.75 in one year ($100 multiplied by 1.0675). *Id*. Conversely, $100 received one year from now is worth only $93.68 today ($100 divided by 1.0675). *Id*. The forecast Program Case and 7(b)(2) Case rates for the rate period and the four ensuing years represent income to BPA and through the 7(b)(2) rate test, an amount of rate protection Preference power customers receive in those years. *Id*. As described above, given the concept of the time value of money, income and rate protection in some future year is worth less to BPA and its customers than income and rate protection today. *Id*. That difference in value has to do with the potential interest income if the money associated with rate protection is in hand or the potential interest cost if the money associated with rate protection will be available only at some future time. *Id*. at 53-54. The current discounting methodology, which uses BPA's borrowing rate, makes BPA and its customers indifferent to when in the rate period (plus the ensuing four years) revenue from the rates and the rate protection is received. *Id*. at 54.
By contrast, PPC *et al*.'s suggestion that BPA simply use GDP deflators to put a series of annual nominal dollar rates in the real dollars of the current year is clearly not the same as using an interest earning rate to determine the time value of money. *Id*.

<u>Decision</u>

BPA will continue its longstanding use of its projected borrowing rate for each year to discount projected Program Case rates and 7(b)(2) Case rates.

10.7 Implementation Methodology

Issue 1

Whether BPA should revise the Implementation Methodology by taking the results of the Rate Analysis Model as currently implemented, and then changing the level of net REP benefits included in rates for the rate period by averaging in the net benefit levels projected by the model for the remainder of the rate test period.

Parties' Positions

The OPUC recommends that BPA use the average discounted difference between the Program and 7(b)(2) Cases to determine the level of REP benefits available in each year of the rate test period, and conversely, the level of costs that must be excluded from preference customers' rates for each test year (as it does in the current methodology). OPUC Br., WP-10-B-PU-01, at 1-6. Under the OPUC's recommended alternative, BPA would then take the average of the rate period REP benefits and the out-year average REP benefits to derive the level of allowable REP benefits that can be provided while meeting the 7(b)(2) rate protection requirement. *Id*.

PPC *et al*. argue that the OPUC proposal would fundamentally alter the operation of the rate test and depart from the requirement that the rate test operate as a cap on the costs preference customers can be charged for the residential exchange. PPC *et al*. Br., WP-10-B-JP11-01, at 15.

BPA Staff's Position

It is inappropriate to use the FY 2010-2011 rate test to calculate PF Exchange rates to estimate the FY 2012-2013 rate period and FY 2014-2015 rate period REP benefits. Doubleday *et al*., WP-10-E-BPA-39, at 57.

Evaluation of Positions

The OPUC notes that, at a December 2008 customer workshop regarding BPA's upcoming WP-10 rate case, Staff provided interested persons with documents demonstrating how altering ASC trajectory assumptions for the multi-year 7(b)(2) rate test period changes net REP benefits for the rate period. OPUC Br., WP-10-B-PU-01, at 1. The OPUC states that the document demonstrates that the level of REP benefits determined for the rate period under the Implementation Methodology can dramatically decrease if the ASCs of participating utilities are assumed to increase in the out-years of the rate test period, relative to other costs, and significantly increase if the converse is assumed. *Id*. The OPUC interpreted BPA's discussion of these effects of the Implementation Methodology as an invitation to parties to suggest modifications to the Implementation Methodology to reduce the magnitude of the impacts discussed at the workshop. *Id*. After learning of this issue at the December 2008 customer workshop, the OPUC investigated how to modify the Implementation Methodology to address the issue discussed by Staff while maintaining the rate protection mandated by statute. *Id*. The OPUC arrived at several potential solutions, all of which change how the 7(b)(2) rate test results are translated into the determination of REP benefits provided to exchanging utilities during each rate period. *Id*. Specifically, the OPUC recommends that BPA add another step to the Implementation Methodology to determine the level of authorized REP benefits. *Id*.

The OPUC states that Staff's response to the modification suggested by the OPUC is surprising. *Id*. The OPUC believes Staff's response reflects that Staff does not believe that it is necessary, or even desirable, to modify the current Implementation Methodology. *Id*. at 1-2. The OPUC states that while it anticipated the possibility that Staff would not accept the OPUC's proposal, the OPUC did not anticipate that Staff would reject the underlying premise, that the current Implementation Methodology may need modification to address the issue discussed at the December 3, 2008, customer workshop. *Id*. at 2. The OPUC states that Staff primarily criticizes the premise underlying the OPUC's proposed change—that the current Implementation Methodology yields counterintuitive and inequitable results. *Id., citing* Doubleday *et al*., WP-10-E-BPA-39, at 56.

The OPUC's comments are helpful to understand its perspective. The information Staff provided at BPA's December 3, 2008, customer workshop was to demonstrate to parties that higher ASCs do not always lead to higher REP benefits. It was also to show that the 7(b)(2) rate test was working as designed; that is, the 7(b)(2) rate test protected the COUs from the relevant costs identified in that section, all else being equal. BPA acknowledges that some parties may believe that it would be appropriate for BPA to modify the Implementation Methodology to address the fact that the level of REP benefits determined for the rate period under the Implementation Methodology can dramatically decrease if the ASCs of participating utilities are assumed to increase in the out-years of the rate test period, relative to other costs, and significantly increase if the converse is assumed. The OPUC, and other parties such as APAC who attempted to directly address this issue, should be commended for their time and efforts to address this difficult matter. Although BPA is not choosing to adopt the proposals proffered by the OPUC and APAC, BPA greatly appreciates their efforts and encourages the parties to continue to think about ways to address this issue. Staff's defense of BPA's current methodology defends that methodology against the parties' newly proposed specific methodologies rather than asserting the perfection of the existing methodology. Admittedly, Staff's defense does not establish that BPA's current methodology is perfect; nevertheless, Staff sought to establish that its proposal comprises a successful implementation of section 7(b)(2) of the Northwest Power Act.

Staff noted that BPA's current methodology focuses on the level of costs that need to be excluded from the public customers' rates in order to provide rate protection to those customers. Doubleday *et al*., WP-10-E-BPA-39, at 54. The plain language of section 7(b)(2) supports the current methodology:

> (2) After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) of this section for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator assumes that—

(A) the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are—

(i) served by the Administrator, and

(ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives;

(B) public body, cooperative, and Federal agency customers were served, during such five-year period, with Federal base system resources not obligated to other entities under contracts existing as of December 5, 1980, (during the remaining term of such contracts) excluding obligations to direct service industrial customer loads included in subparagraph (A) of this paragraph;

(C) no purchases or sales by the Administrator as provided in section 839c(c) of this title were made during such five-year period;

(D) all resources that would have been required, during such five-year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were—

(i) purchased from such customers by the Administrator pursuant to section 839d of this title, or

(ii) not committed to load pursuant to section 839c(b) of this title,

and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator; a

(E) the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from—

(i) reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, and

(ii) reserve benefits as a result of the Administrator's actions under this chapter

were not achieved.

Id. at 54-55.

Although BPA's current methodology may not be perfect, Staff disagrees with the OPUC's contention that the methodology can produce counterintuitive, unstable, and inequitable results. *Id*. at 56. BPA's current methodology calculates an average discounted rate test trigger over the rate period plus the ensuing 4 years. *Id*. In the current rate case, that is a test period of six years. *Id*. Therefore, the rate protection provided to the public customers is an average discounted rate protection over six years, and that protection is applied to the two-year rate period. *Id*. Just as the conduct of the section 7(b)(2) rate test in determining the amount of rate protection afforded

BPA's preference customers is controlled by the language of the Northwest Power Act above, the methodology used to allocate that rate protection amount to other loads is controlled by the language of section 7(b)(3) of the Act:

> (3) Any amounts not charged to public body, cooperative, and Federal agency customers by reason of paragraph (2) of this subsection shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers.

Id. In this rate case, those supplemental rate charges derived from the protection afforded by the 7(b)(2) rate test, which is calculated over the six-year rate test period, are applied only to the two-year rate period loads. *Id*. In this way, the rate test, as measured in this rate case, can affect the rates of only this rate period, FY 2010-2011. *Id*. Similarly, the rate test in this proceeding can affect the REP benefit calculation for only this rate period, FY 2010-2011. *Id*. The OPUC's analysis, as discussed below, makes the error of using the results of the FY 2010-2011 7(b)(2) rate test to calculate REP benefits outside of the FY 2010-2011 rate period. *Id*. at 56-57. This error renders any conclusions drawn from the OPUC's analysis defective. *Id*. at 57. Future REP benefits would be based on the results of future year rate tests, which will have different triggers than the FY 2010-2011 rate test.

The OPUC seems to misunderstand BPA's current 7(b)(2) methodology. *Id*. The first apparent misunderstanding is that, while the FY 2010-2011 7(b)(2) rate test trigger is calculated using the Program Case and 7(b)(2) Case rates for the six-year period, the REP benefits are calculated for only the rate period. *Id*. The OPUC proposes a different approach, which is to look at the level of REP benefits that can be provided over the six-year period. *Id*. The OPUC proposes to look at the level of REP benefits for the FY 2012-2013 rate period and the FY 2014-2015 rate period, but calculated with the 7(b)(2) rate test trigger of the FY 2010-2011 rate case period. *Id*.

The section 7(b)(2) rate test is conducted to determine the rate protection, if any, that should be afforded the PF Preference customers for the rate period. *Id*. In so doing, the rate period PF rate is bifurcated into a rate period PF Preference rate and a rate period PF Exchange rate. *Id*. It is inappropriate to use the FY 2010-2011 rate test to calculate PF Exchange rates to estimate the FY 2012-2013 rate period and FY 2014-2015 rate period REP benefits. *Id*.

The OPUC argument uses its own definitions of rate protection and allowable REP benefits. *Id*. at 58. First, any particular level of REP benefits, even if it is constant over some period of time, cannot be defined as "meeting the 7(b)(2) rate protection requirements." *Id*. The section 7(b)(2) rate test determines the amount of rate protection, not REP benefits. *Id*. The allowable REP benefits are a result of that rate protection, not the cause of the rate protection. *Id*. Second, the OPUC describes the values in its analysis as discounted values. *Id*. At a discount rate of about 6.75 percent per year used by BPA, if the discounted total REP costs were to grow from $350 million to $750 million in four years as shown in the OPUC's analysis, a nominal growth rate of 29.2 percent per year would be necessary for the non-discounted REP costs. *Id*. The discounted range of $350 million to $750 million is equal to a non-discounted range of $374 million to $1,040 million, assuming the 6.75 percent annual discount rate. *Id*. By contrast, the non-discounted REP costs before 7(b)(2) in the Initial Proposal grow from $569 million in 2010 to $653 million in 2014, reflecting a nominal growth rate of 3.5 percent per year. *Id*.

BPA recognizes that the analyses provided by the OPUC contained values found in the RAM2010 model used to calculate Initial Proposal rates. *Id*. at 59. However, as stated earlier, because the REP benefit amounts for the years FY 2012-2015 are calculated with the 7(b)(2) rate test trigger from the FY 2010-2011 rate period, they do not accurately reflect what the REP benefits will be in those years. *Id*. The RAM2010 model happens to calculate rates and other related values for years from FY 2010 to FY 2019. *Id*. For the Initial Proposal, the rates calculated for the FY 2010 to FY 2015 rate test period are used to calculate the FY 2010-2011 7(b)(2) rate test trigger. *Id*. The FY 2010-2011 7(b)(2) rate test trigger is the only trigger calculated in the current version of the model, and that trigger amount is used to determine the FY 2010-2011 PF Exchange rate and, lacking an estimate of future triggers, it is used to represent out-year REP benefits for FY 2012-2015. *Id*. It is the inappropriate use of these out-year REP values, based on the FY 2010-2011 rate test trigger, that BPA believes is the flaw in OPUC's approach.

To compare forecasts of REP benefits for the FY 2010-2015 time period, three separate 7(b)(2) rate tests would need to be conducted to calculate three different 7(b)(2) rate test triggers and three different PF Exchange rates: one for the FY 2010-15 test period, one for the FY 2012-17 test period, and one for the FY 2014-19 test period. *Id*. Only then could one compare six years of REP benefit amounts. *Id*. The OPUC did not conduct such an analysis, and that failure renders its conclusions suspect. *Id*.

Staff noted it can use its professional experience to make some estimates about trends in the future without actually conducting an additional two 7(b)(2) rate test calculations. *Id*. Generally, if exchanging utilities' costs increase into the future faster than BPA's costs, the 7(b)(2) rate test trigger will increase and the PF Exchange rate will increase, all else being equal. *Id*. This higher PF Exchange rate relative to participants' ASCs will exert a downward pressure on REP benefits. *Id*.

In the current rate case, participants' ASCs are increasing over time faster than BPA's costs, and it is reasonable to expect that the FY 2012-2013 rate test trigger will be larger than the current FY 2010-2011 rate test trigger. *Id*. at 60. Therefore, it is reasonable to expect that, given that higher trigger, the REP benefits for FY 2012-2013 will be lower than those displayed in the OPUC table. *Id*. Conversely, if the exchanging utilities' ASCs were to decrease over time relative to BPA's costs, it is reasonable to expect that the 7(b)(2) rate test trigger would be lower, the PF Exchange rate would be lower, and REP benefits would be higher, all else being equal. *Id*. Without conducting the analysis, the actual amounts of REP benefits under these two scenarios are uncertain, but the directionality described is logical and intuitive. *Id*.

Staff stated that the BPA workshop the OPUC cites was to provide information to interested parties, and the examples were presented to show that the 7(b)(2) rate test, by design, calculates an average protection amount over the rate period plus the four ensuing years, while applying that rate protection to only the rate period year(s). *Id*. at 60-61. The workshop information showed that different out-year ASCs would logically produce different rate period REP benefits. *Id*. at 61. The Staff statements cited by the OPUC were made in the context of finding a long-term, stable basis for providing REP benefits to REP participants. *Id*. However, such a desire does not mean that section 7(b)(2) can be re-interpreted to shift its focus from rate protection for preference customers to providing REP benefits. *Id*. Any long-term solution to stabilizing REP benefits must be consistent with statute. *Id*. BPA must continue to follow the controlling ratemaking statutes provided by Congress, as set forth in the Legal Interpretation and Implementation Methodology, regardless of regional discussions concerning the stability of REP benefits. *Id*.

The OPUC acknowledges that Staff previously noted that the Act requires the use of a six-year study period to determine rates for a two-year rate period, and a consequence of this is that projected costs for all six years of the study period will affect the rates determined for the two-year rate period. OPUC Br., WP-10-B-PU-01, at 3. As noted above, it is intuitive that increasing ASCs in the out-years of the rate test period will increase the trigger amount in those years, which will put downward pressure on REP benefits for the two-year rate period. *Id*. The OPUC does not dispute in this proceeding that the Act requires BPA to use a six-year study period to determine the level of rate protection necessary for the two-year rate period. *Id*. However, the OPUC claims that any assertion that the Act mandates that BPA determine REP benefits in the manner prescribed by the Implementation Methodology is unsupportable. *Id*. The OPUC states that BPA could choose to modify its approach as long as that approach satisfies the mandates of the Act. *Id*.

The OPUC states that while it may be intuitive that escalating ASCs in the out-years of the rate test period will increase the level of costs to be excluded in the out-years of the rate test period, the level of allowable REP benefits may very well increase in those years. *Id*. at 4. Accordingly, the OPUC claims, it is not intuitive that costs that should be excluded in the out-years should have the effect of dramatically decreasing the level of REP benefits in the two-year rate period. *Id*. The OPUC states that a methodology that allows this dramatic impact is inequitable because it significantly reduces actual REP benefits within the rate period for projected costs that may never materialize. *Id*. The OPUC argument misses the point, however, that the factors that may well increase REP benefits in the out-years, namely, lower BPA costs, would be captured by BPA's methodology. Furthermore, BPA must forecast its costs in the out-years. BPA attempts to make the best forecasts possible. Any forecast is unlikely to exactly capture future costs, however.

The OPUC claims that Staff's argument that the effect at issue is intuitive ignores the fact that the effect is due largely to BPA's methodological choice for mitigating the effect of anomalies during the six-year rate test period for purposes of determining the rate test trigger. *Id*. at 4. The OPUC states that a method for mitigating the effect of anomalies during the rate test period should dampen year-to-year rate adjustments while maintaining overall values, not significantly reduce REP benefits that may be provided to exchanging utilities. *Id*. The 7(b)(2) rate test is not, however, designed to maintain consistent levels of REP benefits. Instead, it is designed to establish preference customer rate protection.

The OPUC notes that Staff concludes that the OPUC recommendations are not persuasive because the analysis on which they are based is flawed. *Id*. The alleged flaw is the OPUC's reliance on estimates of REP benefits in 2012-2013 and 2014-2015 that are based on the rate test trigger for 2010-2011. *Id*. The OPUC states that Staff's summary dismissal of the OPUC recommendations is inappropriate. *Id.* The OPUC states that REP benefit estimates for FY 2012-13 and FY 2014-15 are from BPA's RAM model. *Id.* Staff states in its rebuttal testimony that these estimates are for "display purposes only." *Id.* at 4-5. However, the OPUC notes, the table from which the OPUC obtained these numbers does not include any qualifier noting that the numbers are for "display purposes only." *Id.* at 5. In other parts of the RAM model, values that are only informational have a color-coded tab. *Id.* The OPUC notes that no such color coding was provided in the table used by the OPUC. *Id.* The OPUC states that given that there was no way parties, including the OPUC, could know the numbers were for "display purposes only," Staff's summary dismissal of the OPUC's conclusions based on analysis using these numbers is not warranted. *Id.*

In response, BPA understands the OPUC's frustration with Staff's labeling. Nevertheless, this does not change the true character of the cited estimates.

The OPUC also disagrees that it was inappropriate to rely on these numbers. *Id.* The OPUC states that as noted by Staff in its rebuttal testimony, the RAM model is not currently designed to determine a 7(b)(2) rate test trigger for FY 2012-13 and FY 2014-2015. *Id., citing* Doubleday *et al.*, WP-10-E-BPA-39, at 63. Accordingly, the OPUC reasonably relied on estimates of REP benefits for FY 2012- 2015 based on the rate test trigger for FY 2010-2011. OPUC Br., WP-10-B-PU-01, at 5.

In response, although the OPUC's reliance on the RAM estimates is understandable, this does not make the cited estimates accurate.

The OPUC states that its proposal does not change the interpretation of section 7(b)(2). *Id.* Instead, the OPUC claims, its proposal concerns the methodology BPA has adopted to implement 7(b)(2). *Id.* The OPUC recommends that BPA add a step to how BPA determines REP benefits to lessen what can be a punitive impact from projections of escalating ASCs in the out-years of the rate test period. *Id.* at 5-6. Currently, BPA determines what costs must be excluded from preference customers' rates during the rate period by determining the average of the discounted difference between the Program Case and 7(b)(2) Case rates for all years of the six-year rate test period. *Id.* at 6. The OPUC states that the level of REP benefits provided to exchanging utilities is simply a product of that analysis. *Id.*

The OPUC recommends that BPA add one step to the methodology to determine REP benefits. *Id.* Specifically, the OPUC recommends that BPA use the average discounted difference between the Program and 7(b)(2) Cases to determine the level of REP benefits available in each year of the rate test period, and conversely, the level of costs that must be excluded from preference customers' rates for each test year (as it does in the current methodology). *Id.* Under the OPUC's recommended alternative, BPA would then take the average of the rate period REP benefits and the out-year average REP benefits to derive the level of allowable REP benefits that can be provided while meeting the 7(b)(2) rate protection requirement. *Id.*

The OPUC states that its recommendation is not flawed because it uses the 7(b)(2) rate test trigger determined for the rate period to estimate REP benefits for the subsequent four years of the rate test period. *Id.* The OPUC states that nothing in the Act precludes BPA from using a single discounted rate test trigger over the study period to determine the average REP benefits available under such a rate. *Id*. Further, the OPUC states, the purpose of the multi-year study period is to dampen the effects of large cost shocks, such as the addition of a new large generating plant. *Id., citing* Doubleday *et al*., WP-10-E-BPA-39, at 50. The OPUC believes its proposal satisfies this purpose. OPUC Br., WP-10-B-PU-01, at 6. The OPUC claims the current BPA methodology does not—it results in significant changes in year-to-year REP benefits should ASCs escalate or decrease relatively quickly. *Id*. The OPUC proposal, however, is more seriously flawed than the BPA methodology. The OPUC proposal uses discounted differences between the two Cases as if they were rate test triggers, and then applies the discounted differences to undiscounted ASCs and Program Case rates to determine REP benefits.

The OPUC notes that APAC and PPC *et al*. assert that the OPUC proposal to modify the Implementation Methodology is flawed because the OPUC contemplates using out-year data to determine net REP benefits. *Id*. at 7. The OPUC states that APAC and PPC *et al.* acknowledge that the current 7(b)(2) rate test uses out-year data, but argue that the OPUC proposal to use out-year data to determine REP benefits, as opposed to the 7(b)(2) rate test trigger, is illegal or inconsistent with the Act. *Id*. The OPUC argues that the assertion that it is illegal to use out-year data in the manner it recommends is not supported by the language of the Act. *Id*. Further, the OPUC claims, APAC's assertion that the current Implementation Methodology does not establish the level of 7(b)(2) protection for the out-years of the rate test period is incorrect. *Id*. The Implementation Methodology uses the average discounted triggers over the study period to determine the rate test protection for the rate period. *Id*. The discounted triggers from outside the rate period directly impact the level of rate period REP benefits. *Id*. In fact, the OPUC states, as discussed above, the impetus for the OPUC proposal is the fact that ASC projections for years outside the rate period can dramatically affect rate period REP benefits. *Id*.

The OPUC states that, notably, APAC's own testimony has several recommendations on how to use out-of-rate-period results to affect the PF Exchange rate differential for the rate period. *Id*. The OPUC notes that APAC asserts that "estimates of future benefits should not be used for determination of present benefits when their actual determination will be subject to a future §7(b)(2) process." *Id*. The OPUC states that APAC's criticism fails to acknowledge the mechanics of the current methodology. *Id*. Net REP benefits for each rate period are currently based on estimates of future ASCs, the determination of which is also subject a future process. *Id*. The OPUC states that APAC does not adequately explain why the Act permits BPA to base rate period net REP on estimates of future ASCs but does not permit a similar use of estimates of future net REP benefits. *Id*. at 7-8.

The OPUC states that APAC notes that using estimated REP benefits from out-years of the rate test period is problematic because the rate test is a rolling average of current and future rate period calculations; APAC claims that the OPUC's proposal may incorrectly inflate the level of rate period REP benefits. *Id*. at 8. The OPUC states that APAC merely states the converse of the problem that OPUC attempts to address. *Id*. The OPUC notes that currently, the Implementation Methodology uses a rolling average of costs that must be excluded from Program Case rates to determine the rate test trigger. *Id*. As a consequence, the OPUC states, assumptions of increasing ASCs in the outyears of the rate test period can significantly and artificially raise the level of excludable costs on which the rate test trigger is based. *Id*.

As discussed above, the OPUC states that this effect is inequitable. *Id*. The OPUC states that under its proposal, BPA would still conduct the 7(b)(2) rate test to determine what costs must be excluded from Program Case rates to provide preference customers the rate protection required by statute but would add an additional step to the Implementation Methodology for the purpose of determining REP benefits to ameliorate this inequitable effect. *Id*.

PPC *et al*. argue that the OPUC proposes a drastic modification to the 7(b)(2) rate test Implementation Methodology. PPC *et al*. Br., WP-10-B-JP11-01, at 14. PPC *et al*. claim that under the OPUC's proposal, BPA would take the results of the RAM as currently implemented, and then change the level of net REP benefits included in rates for the rate period by averaging in the net benefit levels projected by the model for the remainder of the Rate Test Period *(i.e.*, the four years following the rate period). *Id*. at 14-15. PPC *et al*. state that this method would fundamentally alter the operation of the rate test and depart from the requirement that the rate test operate as a cap on the costs preference customers can be charged for the residential exchange. *Id*. PPC *et al.* state that the OPUC proposal would have the effect of including projected net REP costs from outside the rate period in current rates. *Id*. PPC *et al*. argue this is a result that is not allowed by the statute, which explicitly spells out that the rate test is to compare two sets of costs, and then exclude costs from the preference customers' rates. *Id*. PPC *et al*. state that Staff's rebuttal testimony presented a position that essentially agrees with PPC *et al*.

The OPUC states that, like the APAC testimony, the PPC *et al*. testimony fails to note that rate test period exchange costs outside of the rate period affect rate period REP benefits. OPUC Br., WP-10-B-PU-01, at 8. The OPUC claims that the PPC *et al*. testimony fails to justify why it is equitable to provide rate protection in the rate period for costs the preference customers have not yet incurred and may never incur. *Id*. The OPUC states that, contrary to the assertions of BPA, APAC, and PPC *et al*., the OPUC does not recommend that BPA subordinate the rate protection found in section 7(b)(2) to the provision of REP benefits. *Id*. The OPUC asserts that the rate protection of section 7(b)(2) is axiomatic and cannot be subordinated in BPA's methodology. *Id*. The OPUC recommends that the Administrator find a way to provide preference customers the rate protection in an equitable manner. *Id*.

In summary, the OPUC has conducted a thoughtful analysis of the foregoing issue and has established a number of valid points. Nevertheless, BPA believes the OPUC analysis was built on faulty assumptions and logic. Doubleday *et al*., WP-10-E-BPA-39, at 63. The OPUC has not demonstrated whether its goal of stable REP benefits is or is not achieved by BPA's implementation of section 7(b)(2). *Id*. The RAM2010 was not designed for the type of analysis that the OPUC is trying to perform. *Id*. The underlying issue raised by the OPUC that the shape of future ASCs affects current REP benefits is worthy of further discussions before and during future rate cases.

<u>Decision</u>

BPA will not revise the Implementation Methodology by taking the results of the RAM and then changing the level of net REP benefits included in rates for the rate period by averaging in the net benefit levels projected by the model for the remainder of the rate test period.

Issue 2

Whether BPA should modify the Implementation Methodology to round the average of the reduced Program Case rates, the average of the 7(b)(2) Case rates, and the rate test trigger to one-hundredth of a mill.

Parties' Positions

No party takes issue with Staff's proposal.

BPA Staff's Position

Staff proposes modifying the Implementation Methodology as follows:

> The discounted average rates will be rounded to the nearest ~~tenth~~ <u>hundredth</u> of a mill per kilowatthour. If the simple average of discounted 7(b)(2) Case rates is less than that of the Program Case rates, then a determination of an amount of rate protection to be reallocated in BPA's rate proposal is required. <u>The difference known as the 7(b)(2) rate test trigger amount will be rounded to the nearest hundredth of a mill per kilowatthour when performing the reallocation.</u>
>
> * * * *
>
> The difference in average discounted rates <u>(rounded to the nearest hundredth of a mill)</u> will be multiplied by the preference customer loads for the Relevant Rate Case to determine the reduction in the 7(b)(2) Customers' rate period costs.

Doubleday *et al.*, WP-10-E-BPA-15, at 6. Staff explains the change would make the calculation of the rate test trigger consistent with the rounding of BPA's power rates. *Id*.

Evaluation of Positions

In addition to making the rounding of the rate test consistent with the rounding of power rates, changing the rounding from one-tenth to one-hundredth would make the effects of changes in costs or revenue credits used in calculating the trigger more proportionate to the magnitude of the changes. *Id*. The modification does not bias the results toward either the PF Preference customers or those receiving REP benefits. *Id*. No party objects to the proposed change either in testimony or in brief.

Staff was somewhat imprecise in its proposed language changes. For example, the second addition states that "the 7(b)(2) rate test trigger amount will be rounded to the nearest hundredth of a mill." The trigger amount is expressed in dollars, not mills per kilowatthour. Therefore, the trigger amount is not rounded as Staff proposes. Further, the third change is unnecessary; it logically follows that if the average of the discounted rates is rounded, the resulting difference is also rounded to the same level of precision. Therefore, the only change necessary in the Implementation Methodology is the first change of "tenth" to "hundredth."

Decision

BPA will modify the Implementation Methodology to round the average of the reduced Program Case rates, the average of the 7(b)(2) Case rates, and the rate test trigger to one-hundredth of a mill.

10.8 Tiered Rates Adjustment to Conservation

Issue 1

Whether a reduction should be made in projected BPA conservation for the future tiered rate period.

Parties' Positions

No party advocated this adjustment in its Initial Brief.

The IOUs opposed the adjustment based on APAC's direct testimony. IOU Br., WP-10-B-JP1-01, at 40-42.

In its Brief on Exceptions, APAC notes that the Draft ROD suggests that no party raised this issue, but APAC raised the issue both in its testimony and in its Initial Brief. APAC Br. Ex., WP-10-R-AP-01, at 3. APAC suggests the issue should be deemed raised by its incorporation in the Order Incorporating Evidence and Arguments, but APAC also cited in its Initial Brief additional evidence presented in this case demonstrating that the rationale for load augmentation was arbitrary and capricious. *Id*.

BPA Staff's Position

In rebuttal testimony, BPA Staff opposes the 50 percent conservation reduction adjustment attributable to tiered rates that APAC proposed for rate test period years FY 2012-2015. Doubleday *et al*., WP-10-E-BPA-39, at 6-8, *citing* Wolverton, WP-10-E-AP-01, at 8. APAC did not choose to advance this issue after this point in the WP-10 rate proceeding.

Evaluation of Positions

Section 1010.13(b) of BPA's Rules of Procedure Governing Rate Hearings states that "[p]arties whose briefs do not raise and fully develop their positions on any issue shall be deemed to take no position on such issue. Arguments not raised are deemed to be waived." No party argued in brief that a reduction should be made in projected BPA conservation savings attributable to the implementation of tiered rates for rate test period years FY 2012-2015.

APAC misunderstands the purpose of the citation in the Draft ROD that "[n]o party advocated this adjustment in its Initial Brief." BPA was not attempting to dismiss the positions held by APAC, or any other party, with such statement. Positions held in the WP-07 Supplemental proceeding are preserved in this proceeding. The statement in the Draft ROD was particular to parties raising the issue in Initial Brief in the instant proceeding. APAC's citation to its Initial Brief in this proceeding was in reference to its *preservation of its argument from the WP-07 Supplemental proceeding*, and, as such, was not viewed by BPA as a new argument. As the Draft ROD noted, because no party presented any new arguments in their Initial Briefs, BPA did not need to recite its argument from the WP-07 Supplemental proceeding simply to reply to the IOUs' opposition to the issue raised in APAC's testimony.

Decision

No party argued in brief that a reduction should be made in projected BPA conservation for the tiered rate period; therefore, the issue will not be addressed.

10.9 Conservation Load Augmentation

Issue 1

Whether BPA should 1) eliminate "load augmentation due to conservation programs" in the determination of general requirements of BPA's preference customers in the 7(b)(2) Case and 2) remove those conservation programs from the section 7(b)(2)(D) resource stack.

Parties' Positions

In the Draft ROD, BPA notes that no party advocated this general adjustment for the first time in its Initial Brief. However, in its Brief on Exceptions, APAC notes that its Initial Brief does present a "new" argument related to this basic argument. APAC Br. Ex., WP-10-R-AP-01, at 2. APAC claims that BPA removed a Chelan PUD resource from the section 7(b)(2)(D) resource stack because it was already serving load and reducing the load obligation; therefore, conservation should be treated the same way. APAC Br., WP-10-B-AP-01, at 4.

The IOUs opposed the general adjustment based on APAC's direct testimony. IOU Br., WP-10-B-JP1-01, at 36-40.

BPA Staff's Position

BPA Staff opposed the general adjustment in rebuttal testimony. Doubleday *et al*., WP-10-E-BPA-39, at 2-4.

Evaluation of Positions

In its Brief on Exceptions, APAC argues that, among reserved issues, particular attention should be paid to the issue regarding the treatment of conservation, both in augmenting load and in using existing conservation in the section 7(b)(2)(D) resource stack in the 7(b)(2) rate test. APAC Br. Ex., WP-10-R-AP-01, at 3. APAC states that it cites in its Initial Brief additional evidence presented in this case demonstrating that the rationale for load augmentation was arbitrary and capricious. *Id*. APAC's Initial Brief states that Staff removed a resource from the section 7(b)(2)(D) resource stack because it was already serving load and was reducing the load obligation under the Program Case and 7(b)(2) Case. APAC Br., WP-10-B-AP-01, at 2. APAC refers to a Chelan PUD resource. *Id. citing* Doubleday *et al*., WP-10-E-BPA-15, at 16-17. This Staff testimony states:

> We conclude that the power sold by Chelan County PUD through its power sales contracts with Colockum and/or Alcoa, which have provided power to Alcoa's Wenatchee smelter since 1957, is serving native load of Chelan County PUD and therefore is not available to the 7(b)(2) resource stack. Even if this load were determined not to be native load of Chelan County PUD, this load is being met by

> Chelan County PUD throughout the rate test period and is thereby reducing the Administrator's load obligations during this period, and thus this load is not includable in the resource stack.

APAC Br., WP-10-B-AP-01, at 2. APAC states that the Chelan PUD resource is like existing conservation. *Id*. (footnotes omitted). APAC asserts that conservation is already in place serving load and reducing the load to be served under the Program Case and the 7(b)(2) Case. APAC Br., WP-10-B-AP-01, at 2. APAC argues that the Chelan PUD resource described in Staff testimony fits the definition of "resource" under the Northwest Power Act, and yet BPA is not compelled under the 7(b)(2) Implementation Methodology to put it into the section 7(b)(2)(D) resource stack. *Id*. APAC claims that, using the same approach, even if conservation fits within the definition of "resource," there is no reason to augment load for existing conservation savings and make existing conservation programs a resource in the section 7(b)(2)(D) resource stack. *Id*.

BPA did not recognize that APAC was offering *new* argument, because it was subsumed within the section of APAC's Initial Brief that dealt with reserved WP-07 Supplemental issues, and BPA did not differentiate APAC's new argument from its reserved arguments. Because APAC raises the new argument again in its Brief on Exceptions, BPA will address APAC's argument in this Final ROD.

APAC's argument is not persuasive, however, because APAC fails to recognize section 7(b)(2)'s requirements for including resources such as conservation in the section 7(b)(2)(D) resource stack. Conservation is a Type 1 resource; that is, a resource purchased from public bodies and cooperatives by the Administrator pursuant to section 6 of the Northwest Power Act, which is therefore included in the section 7(b)(2)(D) resource stack. 16 U.S.C. § 839e(b)(2)(D). BPA has consistently included conservation in the section 7(b)(2)(D) resource stack since the very first rate case subject to the 7(b)(2) rate test provisions of the Act in 1985. This long-term, consistent, and well documented practice can scarcely be considered arbitrary and capricious. Chelan's hydro resources, Rocky Reach, Rock Island, and Chelan, are not Type 1 resources, because BPA has not purchased such resources from Chelan PUD. Therefore, APAC's analogy fails, because BPA cannot include the Chelan PUD resources in the section 7(b)(2)(D) resource stack in the same manner as conservation when Chelan PUD's resources have not been acquired by the Administrator. Section 7(b)(2)(D)(i) (Type 1 resources) does not carry the test of "not committed to load" as does section 7(b)(2)(D)(ii) (Type 2 resources). Therefore, Type 1 resources are to be included in the section 7(b)(2)(D) resource stack without further examination as to whether they would have been committed to load absent BPA's purchase.

In addition, Chelan PUD's hydro resources are not included as Type 2 resources because the entire output of these resources is committed to the loads of COUs and IOUs in the region. As outlined above, Chelan PUD's power sales contract with Colockum and/or Alcoa, which have provided power to Alcoa's Wenatchee smelter since 1957, serves native load of Chelan PUD. None of Chelan PUD's hydro resources meet the definition of a 7(b)(2)(D)(ii) resource (existing 7(b)(2) Customer resources not currently committed to regional load by COUs or IOUs).

In summary, there is no basis to include Chelan PUD's hydro resources in the 7(b)(2) stack as either a Type 1 or a Type 2 resource. BPA is reasonable in excluding Chelan PUD's hydro resources from the section 7(b)(2)(D) resource stack and reasonable in documenting and establishing the amount of conservation resources (together with billing credit resources) that have determined the 7(b)(2) Case load augmentation amount and the amount of conservation resources that are available to serve 7(b)(2) Customer loads from the section 7(b)(2)(D) resource stack.

Section 1010.13(b) of BPA's Rules of Procedure Governing rate hearings states that "[p]arties whose briefs do not raise and fully develop their positions on any issue shall be deemed to take no position on such issue. Arguments not raised are deemed to be waived." No party argued in brief that a reduction should be made in projected BPA conservation for the tiered rate period. To the extent an issue has been reserved pursuant to the Order Incorporating Evidence and Arguments, the issue is preserved in this WP-10 Rate Proceeding.

Decision

No party offered substantive new argument in brief that BPA should 1) eliminate "load augmentation due to conservation programs" in the determination of general requirements of BPA's preference customers in the 7(b)(2) Case and 2) remove those conservation programs from the section 7(b)(2)(D) resource stack; therefore, the issue will not be addressed. However, issues reserved pursuant to the Order Incorporating Evidence and Arguments are preserved in this WP-10 rate proceeding. Having reviewed APAC's foregoing argument in conjunction with any reserved arguments on this issue, BPA will not change its previous decision.

10.10 Repayment Study

Issue 1

Whether BPA properly establishes a repayment study in the 7(b)(2) Case.

Parties' Positions

Cowlitz argues that BPA simply used the repayment study to reclassify Program Case interest and amortization associated with conservation as interest and amortization associated with Federal resources in the 7(b)(2) Case. Cowlitz Br., WP-10-B-CO-01, at 16-17. Cowlitz states that BPA, as it did in the WP-07 Supplemental rate proceeding, failed to perform a repayment study for the 7(b)(2) Case that reflected the conservation selected for use in the case. *Id*.

BPA Staff's Position

In the WP-07 Supplemental rate proceeding, BPA developed different revenue requirements, based on different repayment studies, for the Program Case and the 7(b)(2) Case. Doubleday *et al.*, WP-07-E-BPA-85, at 17. One is derived (allocated) from the total Program Case revenue requirement, and the other is derived from the total revenue requirement developed specifically for the 7(b)(2) Case, based on the relevant assumptions that guide the two respective Cases. *Id*.

Evaluation of Positions

Cowlitz previously raised this issue in BPA's WP-07 Supplemental rate proceeding. Pursuant to the Standstill Agreement, all litigants' previous arguments on this issue have been preserved and will not be repeated here.

Decision

In BPA's WP-07 Supplemental ROD, BPA concluded that it properly establishes a repayment study in the 7(b)(2) Case. Cowlitz previously raised this issue in BPA's WP-07 Supplemental rate proceeding. Pursuant to the Standstill Agreement, all litigants' previous arguments on this issue have been preserved.

10.11 Uncontrollable Events

Issue 1

Whether BPA should identify and include uncontrollable events in the section 7(b)(2) rate test.

Parties' Positions

The IOUs argue that BPA should identify and include uncontrollable events in the section 7(b)(2) rate test. IOU Br., WP-10-B-JP1-01, at 28.

BPA Staff's Position

In the WP-07 Supplemental rate proceeding, BPA Staff did not exclude from the Program Case costs that are due to conditions that simply vary over time and are typically reflected in rates. Doubleday *et al.*, WP-07-E-BPA-85, at 143. Staff also stated that, as noted in the Implementation Methodology, Uncontrollable Events are not properly viewed as all conceivable events beyond BPA's control, but rather the discrete and significant events beyond BPA's control that differ from the continuum of changing conditions that occur in nature, business, and government and are routinely reflected in rate development. *Id*.

Evaluation of Positions

The IOUs previously raised this issue in BPA's WP-07 Supplemental rate proceeding. IOU Br., WP-07-B-JP6-01. Pursuant to the Standstill Agreement, all litigants' previous arguments on this issue have been preserved and will not be repeated here.

Decision

In the WP-07 Supplemental Rate Proceeding, BPA determined that the section 7(b)(2) rate test will not exclude the costs of WNP-1 and WNP-3, starting financial reserves available for risk, or PNRR as costs of Uncontrollable Events. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 264. BPA adopted the definition of Uncontrollable Events in the proposed Legal Interpretation. Id. The IOUs previously raised this issue in BPA's WP-07 Supplemental rate proceeding. Pursuant to the Standstill Agreement, all litigants' previous arguments on this issue have been preserved.

11.0 SLICE RATE AND REVENUE REQUIREMENT

11.1 Introduction

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

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

Each Slice customer pays a percentage of BPA's costs, rather than a set price per megawatt and megawatthour. The Slice customer's obligation to pay is based on the percentage of the FCRPS generation output the Slice customer elected to purchase in its 10-year Subscription contract. The Slice customers pay that same percentage of the Slice Revenue Requirement. The Slice Revenue Requirement is comprised of all of the line items in BPA's power revenue requirement, with certain limited exceptions. *See* the Slice Product Costing and True-Up Table for a detailed list of the line items and forecasted dollar amounts in the FY 2010-2011 Slice Revenue Requirement. Wholesale Power Rate Schedules and General Rate Schedule Provisions (GRSPs), WP-10-E-BPA-07, Appendix A, Table 1; *see also* Appendix B to this ROD, WP-10-A-02, Appendix A, Table 1.

In 2003, BPA was involved in litigation before the Ninth Circuit concerning the appropriate interpretation of the Slice rate and the Slice Rate Methodology. *Northwest Requirements Utilities, et al. v. Bonneville Power Administration*, No. 03-73849; *Northwest Requirements Utilities v. Bonneville Power Administration*, No. 04-71311; *Benton County PUD, et al. v. Bonneville Power Administration*, No. 03-74179. In July 2006, BPA, the Slice customers, and the Northwest Requirements Utilities agreed on a settlement of the issues. The Slice Settlement (No. 07PB-12273) was approved by the U.S. Department of Justice and was signed and executed by all parties on November 22, 2006. The Slice Settlement resolved all Slice True-Up disputes for Contract Years 2002-2005, along with some previously disputed substantive issues, in a way that has precedential effect after 2005. The Slice Settlement provided for refunds to Slice customers in the form of credits to their bills, which settled disputes over the magnitude of Slice True-Up Adjustment Charges for FY 2002-2005. The Slice Settlement also included a new dispute resolution provision and a Memorandum of Understanding regarding BPA's Debt Optimization Program. The WP-10 Initial Proposal clarifies that Slice Settlement modifications of the rate treatment of certain Slice Rate and Slice Rate Methodology matters will be applicable for FY 2010-2011. Wholesale Power Rate Development Study, WP-10-FS-BPA-05, section 2.15.

As part of the WP-07 Final Proposal, BPA, along with many Slice customers, non-Slice customers, IOUs, and Tribal entities, signed the Partial Resolution of Issues, which included modifications to the Slice rate and Slice True-Up. Evans *et al.*, WP-07-E-BPA-31, Attachment A. The Partial Resolution of Issues was adopted by the Administrator in the WP-07 Administrator's Final Record of Decision, WP-07-A-02, at 2-6 and Attachment 1. The WP-10 Slice provisions are consistent with the modifications to the Slice rate and Slice True-Up that were included in the Partial Resolution of Issues for FY 2010-2011. Wholesale Power Rate Development Study, WP-10-FS-BPA-05, section 2.15.

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

The WP-10 Initial Proposal identified a potential increase in non-Slice rates resulting from a feature of the Slice True-Up Adjustment Charge. Lee *et al*., WP-10-E-BPA-21, at 7. This potential increase was characterized as a "potential cost shift," but the phrase "potential cost increase for non-Slice customers" may be a more accurate phrase, because no costs are actually shifted from Slice to non-Slice rates. The potential cost increase was related to additional Planned Net Revenues for Risk needed to compensate for the fact that a Slice True-Up Adjustment Charge, payable to BPA, was forecast for FY 2011. *Id*. Pursuant to the Slice Rate Methodology, Slice customers would not make actual cash payments to BPA until early FY 2012. These cash payments would not be available for BPA's annual payment to the U.S. Treasury on September 30, 2011. *Id*. Any PNRR added to the non-Slice revenue requirement as a consequence of the timing of payment of the forecast FY 2011 Slice True-Up Adjustment Charge would be a cost increase for non-Slice customers. *Id*. In the WP-10 Initial Proposal, Staff addressed this potential cost increase by moving portions of certain cost categories in the Slice Revenue Requirement from FY 2011 to FY 2010 so that the forecast of the FY 2011 Slice True-Up Adjustment Charge was zero, which eliminated the potential PNRR increase. *Id*. at 8.

Staff stated that it might be possible to address the cash payment timing effects of the forecast Slice True-Up Adjustment Charge by temporarily relying upon either Transmission Services cash reserves or encumbered Power Services reserves, either of which would be replenished in early FY 2012 when the payments for Slice customers are received. Lee *et al.*, WP-10-E-BPA-38, at 6. Due to circumstances that are specific to its current financial situation, BPA will rely on such reserves instead of shifting portions of certain cost categories in the Slice Revenue Requirement from FY 2011 to FY 2010. The specific circumstances allowing this reliance on reserves are as follows: 1) the cash payments for the Slice True-Up Adjustment Charge are highly certain to be received by BPA; 2) the delay in BPA's receipt of the cash payments from the end of the rate period is only between three and five months; 3) during the delay in BPA's receipt of the cash payments, BPA expects that the encumbered Power Services reserves and reserves attributed to Transmission will not be otherwise drawn upon during the time until the payments for the Slice True-Up Adjustment Charge will have been received by BPA; and 4) the Slice True-Up Adjustment Charge is relatively small in comparison to the reserves that can temporarily cover for the delay in receiving the related cash payments. Documentation for

Revenue Requirement Study, TR-10-E-BPA-01A, Table 9-2, at 72; Risk Analysis and Mitigation Study, WP-10-E-BPA-04, Table 2, at 38. BPA recognizes that while this reliance on reserves is prudent for FY 2010-2011, it is not a suitable long-term solution, because the circumstances related to the availability of encumbered reserves and reserves related to Transmission and the size of the Slice True-Up Adjustment Charge cannot be counted on to hold in future rate periods. As these circumstances change, alternative solutions to the issue of timing of the payment of the forecast Slice True-Up Adjustment Charge will need to be considered in future rate periods. Lee *et al.*, WP-10-E-BPA-38, at 12-13.

11.3 Issues

Issue 1

Whether BPA should true up the net cost of DSI service as part of the calculation of the Slice True-Up Adjustment Charge.

Parties' Positions

The Slice Customers Group urges BPA to forgo the implementation of Staff's suggestion to include in the calculation of the Slice True-Up Adjustment Charge a charge or credit based on actual DSI loads served by BPA. Slice Br. Ex., WP-10-R-JP4-01, at 10. Snohomish also does not support the implementation of Staff's suggestion. Snohomish Br. Ex., WP-10-R-SN-01, at 6-7.

BPA Staff's Position

Staff proposed the Industrial Cost Adjustment Clause (ICAC) as a means to adjust cost-based rates, including the Slice rate, based on actual DSI service levels and resultant costs. Burns *et al.*, WP-10-E-BPA-45, at 47. The ICAC was rejected as a mechanism for adjusting rates in the Draft ROD. Under the Staff proposal, the ICAC would have adjusted the Slice rate each month based on smelter operations based on then-current knowledge or expectations about DSI service conditions before the beginning of each month. *Id*. at 24-25. After the Draft ROD was published, Staff suggested modifying the Slice True-Up Adjustment Charge calculation to adjust the net cost of DSI service to account for the difference between forecast and actual DSI loads. *See* PNGC Br. Ex., WP-10-R-PN-01, Exhibit A, at 9.

Evaluation of Positions

The Slice Customers Group notes that BPA has engaged in augmentation of one sort or another throughout the term of the current Slice contract. Slice Br. Ex., WP-10-R-JP4-01, at 4. This has included short-term balancing purchases, longer-term purchases to cover contractual service obligations in excess of the Federal base system capability, and the purchase and sale of secondary energy attendant to operating the FBS. *Id*. These purchase activities have been undertaken, from time to time, for both PF and DSI loads. *Id*.

The Slice Customers Group notes that the Slice product and rate are based on the premise that each Slice customer agrees to take its share of the output of the FBS without augmentation as and when available, and in return agrees to pay its share of the actual costs incurred by BPA. *Id*.

Slice purchasers pay BPA's actual costs in order to receive shares of the actual FBS output, but they do not receive a share of power obtained through BPA's augmentation activities. *Id.* In light of these differences between the Slice product and rate compared to BPA's other PF products and rates, BPA has employed a practical approach to the treatment of augmentation costs that has reconciled these differences in the PF rates charged to preference customers. *Id.* at 5.

The Slice Customers Group further notes that since the inception of the current Slice contract, BPA has taken the view that the costs of augmentation are system costs that should be borne by all preference customers regardless of the power product or PF rate under which they purchase. *Id.* In the case of Slice customers, this has meant bearing a share of augmentation costs (such as augmentation for PF and DSI service). *Id.* at 5-6. BPA has included the forecast *net* augmentation costs in the base PF Slice rate throughout the term of the current Slice contract. In recognition that Slice customers do not share in the tangible benefits from augmentation, BPA offsets the *gross* augmentation costs included in the Slice rate with the revenues expected to be recovered from the sales of such power. In addition, the costs paid by Slice purchasers do not include any costs associated with short-term balancing purchases. The Slice Customers Group notes that while this approach is not precisely accurate, it has been an essentially fair way to treat the PF and DSI augmentation costs and has worked reasonably well for the term of the current Slice contract. *Id.* at 8.

The Slice Customers Group states that there are complicated issues related to the true-up of augmentation costs. *Id.* at 8. Because the calculation of the Slice True-Up Adjustment Charge would require a comparison of forecast augmentation costs to actual augmentation costs, truing up augmentation costs would require a determination of which BPA power sales and purchases during the course of a year were the "actual augmentation" transactions and what costs were associated with them. *Id.* at 6. The Slice Customers Group states that this would present an administrative nightmare for BPA, as there is no good way to make such a determination in order to do a reasonably accurate comparison of forecast to actual augmentation costs. *Id.*

The Slice Customers Group argues that the suggested change to the calculation of the Slice True-Up Adjustment would be a major departure from the way BPA has historically treated augmentation under the Slice product and rate. *Id.* at 8. BPA notes, however, that the Load-Based Cost Recovery Adjustment Clause (LB CRAC) that was put in place by the WP-02 Supplemental rate case was specifically designed to calculate and collect the changing cost of augmenting the system through the five-year rate period. Nevertheless, BPA agrees that the simplest and least contentious method of charging Slice customers for their share of the net cost of DSI service is to include the forecast net cost of DSI service in the Slice rate and not true up such net cost as part of the Slice True-Up Adjustment Charge calculation.

Finally, the Slice Customer Group and Snohomish state that BPA's suggestion to include in the calculation of the Slice True-Up Adjustment Charge a charge or credit based on actual DSI loads served by BPA was first made in a rate meeting after the testimonial stage of this proceeding had concluded. *Id.* at 9; Snohomish Br. Ex.,WP-10-R-SN-01, at 7. The Slice Customers Group notes that there is no testimony or evidence in the record of this case on this suggestion, and the first time this topic will appear in that record will be in the Final Record of Decision. Slice

Br. Ex., WP-10-R-JP4-01, at 9. The Slice Customers Group states that the timing of this suggestion has resulted in the parties to this case having no opportunity to question, analyze, and understand the potential impacts of this suggestion, or to offer alternative approaches once the issue is understood. *Id*. The Slice Customers Group states that at the least, this approach has deprived the parties of their procedural rights under section 7(i) of the Northwest Power Act. *Id*.

BPA agrees that the lateness of the proposal to true up the net cost of DSI service as part of the Slice True-Up Adjustment Charge calculation is not the best manner in which to proceed. A matter as significant as this should be raised earlier in the proceeding to afford parties the opportunity to present evidence on the record. Although the topic of including changing DSI augmentation costs was proposed as part of the ICAC, that proposal did not deal with the complications associated with the Slice True-Up Adjustment Charge.

Decision

BPA will not true up the net cost of DSI service as part of the calculation of the Slice True-Up Adjustment Charge.

12.0 DIRECT SERVICE INDUSTRIES RATE AND ASSUMPTION FOR SERVICE

12.1 <u>Introduction</u>

In the *Bonneville Power Administration's Service to Direct-Service Industrial (DSI) Customers for Fiscal Years 2007-2011 – Administrator's Record of Decision* and in the *Supplement to Administrator's Record of Decision on Bonneville Power Administration's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011*, BPA determined to offer DSI aluminum companies power sales contracts for an aggregate 560 aMW of benefits at a capped cost of $59 million. In addition, BPA offered a 17 aMW surplus firm power sales contract for Port Townsend Paper Company through the local public utility under the FPS rate (or the Industrial Firm Power (IP) rate, if viable) at a price approximately equivalent to, but in no case less than, the utility's lowest-cost PF rate. BPA decided to allocate a share of the 560 aMW of service benefits to each DSI aluminum company for purposes of making an initial offer of service. Because of the financial risks inherent in providing actual power, and in order to meet the known and capped cost prerequisite, BPA determined that the delivery mechanism would be to monetize the value of the below-market power sales to provide service benefits through cash payments.

On December 17, 2008, the Ninth Circuit issued an opinion in *Pacific Northwest Generating Cooperative, et al., v. Dept. of Energy; Bonneville Power Admin.*, 550 F.3d 846 (9th Cir. 2008) (*PNGC*). The Court invalidated the rate underpinnings of the power sales contracts to the DSIs. This opinion was issued less than a month prior to the expected release of the Initial Proposal, resulting in a delay of a few weeks in the commencement of this rate proceeding. As a result of the Court's opinion, Staff removed from the Initial Proposal the assumptions of DSI service that were at issue in *PNGC*. BPA entered into amendments with Columbia Falls Aluminum Company (CFAC) and Alcoa, replacing the monetary benefits provisions to DSI aluminum smelters with an assumption of a physical power sale at the IP rate. These amendments are effective for FY 2009 only; separate processes will be conducted for the purposes of determining service levels beyond FY 2009. BPA is also working toward changing the Port Townsend Paper assumption from a surplus firm power sale at an FPS rate to an industrial firm power sale at the IP rate. Any agreement with Port Townsend will, like the CFAC and Alcoa amendments, be subject to a public process that will permit interested parties to submit their views.

PNGC also necessitated making a number of changes to the Initial Proposal in this rate proceeding. Because BPA did not believe that it could rely on the contracts reviewed by the Court, Staff assumed for ratemaking purposes that the net cost of the DSI aluminum power sale, the difference between the assumed power purchase price and the revenues from a sale at the IP rate, would equal the $59 million capped financial benefits assumed prior to the *PNGC* opinion. This resulted in an assumed sale of 385 aMW to the DSI aluminum smelters.

A number of parties to *PNGC* have filed for rehearing of the Court's opinion, and the outcome of the rehearing process is not known at this time. Although the mandate of the Court has not attached to the *PNGC* opinion, BPA is nevertheless conforming its ratemaking assumptions to the Court's initial opinion based upon its belief that, while the Court may well modify the language of the opinion in order to provide clarity, the ultimate outcome, as it affects ratemaking, will remain essentially the same.

In addition, BPA is seeking to conform its power sales contracts with the DSIs to the *PNGC* opinion for the WP-10 rate period (FY 2010 and FY 2011). Contracts are not rate matters and are not at issue in this proceeding. However, the outcome of the contracting process bears greatly on ratemaking. Because the contracting process is not concluded at this time, for ratemaking purposes BPA must make assumptions regarding the potential outcomes of the contracting process. These assumptions are at issue in this proceeding.

BPA sells power to DSIs pursuant to section 5(d) of the Northwest Power Act. 16 U.S.C. § 839c(d). Rates for the sale of power to DSIs (the Industrial Firm Power rate) are established pursuant to section 7(c). 16 U.S.C. § 839e(c).

12.2 Section 7(c) Rate Directives

Issue 1

Whether BPA should establish the IP rate on the basis of cost causation.

Parties' Positions

PNGC states that section 9 of the Transmission System Act, 16 U.S.C. § 838g, reaffirmed in section 7 of the Northwest Power Act, 16 U.S.C. § 839e, operates as a significant, substantive, and binding constraint and mandate under which BPA must operate. PNGC Br., WP-10-B-PN-01, at 3-4. PNGC argues that this mandate is not a springboard for expanded BPA discretion in determining whether to recover all costs of DSI service in the IP rates and whether to refrain from allocating any costs of DSI service to the rates paid by BPA's preference customers. *Id.* at 5. PNGC maintains that BPA retains a statutory obligation to serve preference and investor-owned utility customers, but that BPA has no obligation to serve DSI customers. *Id.* PNGC argues that reserving the lowest-possible PF rates for the benefit of consumers throughout the region and providing residential exchange benefits in conformity with sections 5(c) and 7(b) of the Northwest Power Act, 16 U.S.C. §§ 839c(5)(c) and 839e(b), are consistent with BPA's statutory mandates. *Id.* PNGC argues that setting rates for service to DSI customers that do not fully recover the costs of such service, and charging to preference customers the costs not recovered in DSI rates, are actions inconsistent with BPA's statutory mandates. *Id.*

Alcoa argues that PNGC's position misapplies the Transmission Act standard and substitutes an aggregate standard for the express rate standards of section 7(c) of the Northwest Power Act. Alcoa Br., WP-10-B-AL-01, at 5. Alcoa argues that PNGC ignores the rule of statutory construction that the specific provisions control general expressions of intent. *Id.* As a rule, Alcoa argues, when there is an inescapable conflict between general and specific provisions of a statute, the specific will prevail. *Id.* That is, Alcoa continues, when there is in the same section a specific provision and also a general one, which in its most comprehensive sense would include matters embraced in the more specific provision, the general provisions must be understood to affect only those cases within its general language, with the result that the specific controls. *Id.*, *citing* 2A Norman J. Singer, *Sutherland on Statutes and Statutory Construction* §46.05 (6th ed. 2000).

BPA Staff's Position

BPA determines the IP rate in conformance with section 7(c) of the Northwest Power Act. Burns *et al.*, WP-10-E-BPA-45, at 7-20.

Evaluation of Positions

A. Review of Statutory Language and BPA Ratemaking Practice

Section 7(c) of the Northwest Power Act governs the determination of the IP rate. Section 7(c), in pertinent part, states:

> (1) The rate or rates applicable to direct service industrial customers shall be established—
>
> * * * *
>
> (B) 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.
>
> (2) The determination under paragraph (1)(B) of this subsection shall be based upon the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates but shall take into account—
>
> (A) the comparative size and character of the loads served,
>
> (B) the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions, and
>
> (C) direct and indirect overhead costs,
>
> all as related to the delivery of power to industrial customers, except that the Administrator's rates during such period shall in no event be less than the rates in effect for the contract year ending on June 30, 1985.
>
> (3) The Administrator shall adjust such rates to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers.

BPA has summarized its interpretation of this instruction as follows: the IP rate is to be equal to the applicable wholesale rate plus the typical margin, less the value of reserves, plus any section 7(b)(3) reallocation of the section 7(b)(2) rate protection amount. BPA has interpreted the applicable wholesale rate to be the weighted average of the PF Preference rate and the New Resources rate, weighted by sales to preference customers at each rate.

In the ratesetting process, BPA first allocates resource costs pursuant to sections 7(b)(1) and 7(f), with non-resource costs allocated pursuant to section 7(g). 16 U.S.C. §§ 839e(b)(1), (f), and (g). In the allocation of resource costs, first Federal base system costs are allocated to the 7(b) rate pool (PF rates), and then the costs of exchange resources acquired pursuant to section 5(c). 16 U.S.C. §§ 839c(c). If 7(b) loads are not fully served after these allocations, the costs of new resources are allocated to 7(b) loads. All other firm loads, including DSI loads, are allocated the costs of any exchange resources remaining after 7(b) loads are fully served, plus the remaining costs of new resources.

Later in the ratesetting process, section 7(c) is applied to determine the IP rate. BPA forecasts that no preference customer loads will be served at the NR rate, so the applicable wholesale rate is equal to the PF Preference rate. The costs allocated to DSI loads are greater, on a unit cost basis, than the costs allocated to the PF Preference rate, per unit. Because the IP rate is equal to the PF Preference rate plus the typical margin, the costs allocated to each rate are adjusted until the proper relationship between the two rates is attained. This adjustment has been stated as a formula known as the 7(c)(2) Delta.

B. The PNGC Argument

PNGC sees section 9 of the Transmission System Act, 16 U.S.C. § 838g, as a significant, substantive, and binding constraint and mandate under which BPA must operate. PNGC Br., WP-10-B-PN-01, at 3. The Transmission System Act directs that

> Schedules of rates and charges for the sale … 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, (2) having regard to the recovery … of the cost of producing and transmitting such electric power, including the amortization of the capital investment allocated to power over a reasonable period of years and payments provided for in section 838i(b)(9) of this title, and (3) at levels to produce such additional revenues as may be required, in the aggregate with all other revenues of the Administrator, to pay when due the principal of, premiums, discounts, and expenses in connection with the issuance of and interest on all bonds issued and outstanding pursuant to this chapter, and amounts required to establish and maintain reserve and other funds and accounts established in connection therewith.

Transmission System Act, section 9, 16 U.S.C. § 838g.

PNGC notes that section 9 even states the widespread use principle before stating the principles of cost recovery. PNGC Br., WP-10-B-PN-01, at 3. PNGC argues that Congress plainly meant this to be a significant, substantive, and binding constraint and mandate under which BPA must operate. *Id*. at 4.

PNGC argues that the Ninth Circuit held in *PNGC* that this mandate applies to BPA's sales to DSI customers. *Id*. PNGC states that the Court found that helping the DSIs as a means to encourage the widest diversified use of electric power "does not justify a sale of power at below market *or* statutorily mandated rates." *Id., quoting PNGC*, 550 F.3d 846, 876 (9th Cir. 2008) (emphasis by the Court).

PNGC goes on to argue that, in passing the Project Act, Congress especially meant to extend the benefits of low-cost Federal hydroelectric power to the rural and agricultural communities of the Pacific Northwest region. PNGC Br., WP-10-B-PN-01, at 4, *citing* 16 U.S.C. § 832 *et seq*. Relying on the legislative history of the Project Act, PNGC argues that when Congress used the term "widespread," it meant *geographically* widespread, referring to end users and end uses, especially in rural areas. PNGC Br., WP-10-B-PN-01, at 4. PNGC argues that when Congress rejected an amendment that would have allowed Alcoa to purchase all of the output of the Bonneville Project, Congress enacted public preference and priority provisions. *Id., citing* Project Act, section 4, 16 USC § 832c.

PNGC notes that the section 9 of the Transmission System Act is expressly reaffirmed in section 7(a)(1) of the Northwest Power Act, which states that, "Such rates shall be established in accordance with sections 9 and 10 of the [Transmission System Act]…."

PNGC argues that the mandate expressed in these statutes is not a springboard for expanded BPA discretion in determining whether to recover all costs of DSI service in the IP rates and whether to refrain from allocating any costs of DSI service to the rates paid by BPA's preference customers. PNGC Br., WP-10-B-PN-01, at 5. PNGC maintains that BPA retains a statutory obligation to serve preference and investor-owned utility customers, but that BPA has no obligation to serve DSI customers. *Id.* PNGC argues that reserving the lowest possible PF rates for the benefit of consumers throughout the region and providing residential exchange benefits in conformity with sections 5(c) and 7(b) of the Northwest Power Act are consistent with BPA's statutory mandates. *Id., citing* 16 U.S.C. §§ 839c(5)(c) and 839e(b). PNGC argues that setting rates for service to DSI customers that do not fully recover the costs of such service, and charging to preference customers the costs not recovered in DSI rates, are actions inconsistent with BPA's statutory mandates. PNGC Br., WP-10-B-PN-01, at 5.

During the early and mid-1980s, sales to DSI customers reduced BPA's net costs and allowed a lower PF rate than may otherwise have been possible. *Id.* at 6. PNGC states that because BPA had a substantial surplus in the mid-1980s, it did not then have to acquire substantial quantities of power in order to make sales to DSI customers. *Id.* PNGC argues that because this is no longer true, trying to set IP rates as if it were still true is an unwise choice for BPA to make. *Id.* at 6-7. PNGC believes that doing so is contrary to law and an abuse of discretion. *Id.* at 7. PNGC argues that the methodology was developed in 1985 at a time when BPA had a large surplus of power to sell, and sales to DSI customers were a businesslike solution to a problem that produced benefits for DSIs, BPA, and preference customers. PNGC cites to *Portland General Electric v. Bonneville Power Admin.*, 754 F.2d 1475, 1479 (9th Cir. 1985) as affirming its proposition.

C. Analysis of PNGC's Argument

PNGC sets forth a multipart argument leading it to the conclusion that BPA cannot set rates below the resource costs allocated to DSIs. However, to arrive at this conclusion, PNGC places more weight on general rate directives to the exclusion of specific rate directives. While the

Northwest Power Act reaffirms the Transmission System Act direction that BPA must establish the lowest possible rates to consumers consistent with sound business principles, this general language does not allow BPA to ignore the express rate standards of section 7(c).

PNGC argues that the Transmission System Act direction on ratesetting is a significant, substantive, and binding constraint and mandate under which BPA must operate. PNGC Br., WP-10-B-PN-01, at 3. BPA agrees with PNGC that the rate direction given in the Transmission System Act is important. BPA does not agree with the conclusion PNGC draws that this language allows BPA to establish rates for the sale of power to DSIs that are inconsistent with the direction of section 7(c) of the Northwest Power Act. Section 7(c) is specific to the setting of IP rates, and it must be followed.

PNGC states that the Ninth Circuit found that helping the DSIs as a means to encourage the widest diversified use of electric power "does not justify a sale of power at below market *or* statutorily mandated rates." *Id*. at 4, *quoting PNGC*, 550 F.3d 846, 876 (9th Cir. 2008) (emphasis by the Court). This PNGC argument is addressed in Issue 2 of section 12.3 below.

PNGC argues that when Congress rejected an amendment that would have allowed Alcoa to purchase all of the output of the Bonneville Project, Congress enacted public preference and priority provisions. *Id., citing* Project Act, section 4, 16 USC § 832c. That public agencies have preference to Federal power has long been established. "These entities are 'preference' customers, and BPA is required to give priority to their applications for power when competing applications from nonpreference customers are received." *Aluminum Co. of America v. Central Lincoln Peoples' Util. Dist.*, 467 U.S. 380, 384 (1984), 104 S.Ct. 2472 (1984). However, PNGC draws the conclusion that this preference extends to the price of power—that the "lowest rate standard" applies to public agencies. BPA disagrees. The Ninth Circuit has established that the "statute itself couches the preference in terms of 'power sales,' not price." *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1125 (9th Cir. 1984). *Central Lincoln* rejected the premise that preference customers were entitled "to purchase not just available power, but the cheapest available power." *Golden NW Aluminum, Inc. v. BPA*, 501 F.3d 1037, 1046 (9th Cir. 2007).

PNGC also relies on section 7(a)(1) of the Northwest Power Act, which reaffirms section 9 of the Transmission System Act. PNGC argues that this citation to the Transmission System Act establishes that BPA must recover all costs of DSI service in the IP rates and refrain from allocating any costs of DSI service to the rates paid by BPA's preference customers. PNGC Br., WP-10-B-PN-01, at 5. BPA disagrees. Section 7 contains directions that establish both the Transmission System Act reference in section 7(a)(1) and the IP rate in section 7(c).

"If possible, we must give these apparently conflicting provisions a sensible reading that avoids redundancy or surplusage." *Love v. Thomas*, 858 F.2d 1347, 1354 (9th Cir. 1988). "In cases of seeming conflict in the provisions of a statute, the construction which would permit both provisions to stand should be employed." *Korte v. U.S.*, 260 F.2d 633, 636 (1959) (*quoting U.S. v. Moore*, 95 U.S. 760, 763 (1877)). "Under accepted canons of statutory interpretation, [the Ninth Circuit] must interpret statutes as a whole, giving effect to each word and making every effort not to interpret a provision in a manner that renders other provisions of the same statute inconsistent, meaningless or superfluous." *Garcia v. Brockway*, 526 F.3d 456, 463 (9th Cir. 2008) (*quoting Boise Cascade Co. v. EPA*, 942 F.2d 1427, 1432 (9th Cir. 1991) (*citing Aluminum Co. of Amer. v. Bonneville Power Admin.*, 891 F.2d 748, 755 (9th Cir. 1989)). "[W]here possible, provisions of a statute should be read so as not to create a conflict." *Doe v. Rumsfeld*, 435 F.3d 980, 987 (9th Cir. 2006) (*quoting La. Pub. Serv. Comm'n v. FCC*, 476 U.S. 355, 370 (1986)). The courts must interpret a "statute 'as a symmetrical and coherent regulatory scheme' and 'fit, if possible, all parts into a harmonious whole.'" *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 133 (2000) (*quoting Gustafson v. Alloyd Co.*, 513 U.S. 561, 569 (1995); *FTC v. Mandel Bros., Inc.*, 359 U.S. 385, 389 (1959) (internal citations omitted).

> [A] statute ought, upon the whole, to be so construed that, if it can be prevented, no clause, sentence or word shall be superfluous, void or insignificant. This rule has been repeated innumerable times. Another rule equally recognized is that every part of a statute must be construed in connection with the whole, so as to make all the parts harmonize, if possible, and give meaning to each.

Wash. Market Co. v. Hoffman, 101 U.S. 112, 115 (1879).

Unlike PNGC, BPA does not read into the statutes any conflict between the statutory command that BPA must establish the lowest possible rates to consumers consistent with sound business principles and the more specific section 7(c) directive to set an IP rate that is based on the PF Preference rate plus the typical margin. PNGC's argument attempts to re-write the statutory language. The statute states that BPA must establish the lowest possible rates to "consumers." The Northwest Power Act defines "consumer" as "any end user of electric power." 16 U.S.C. § 839a(5). Thus, there is no reason to reach beyond the plain language of the statute, which explicitly includes the mandate to establish the lowest rates possible applicable to "any end user of electric power," which includes the DSIs. There is no basis to conclude, as PNGC apparently has, that Congress used the term "consumers" to refer only to the consumers of preference customers or that Congress conveyed some implicit intent to exempt the DSIs from this provision once sales to that class of consumer became discretionary after the expiration of their 1981 contracts. Simply put, there is no conflict between the two provisions. The statute requires BPA to offer "consumers" the lowest rates possible consistent with sound business principles. The means of providing the lowest DSI rate possible is specifically set forth in section 7(c) of the Northwest Power Act. These are not conflicting provisions. There is a clear general directive to establish the lowest rates possible for all consumers, consistent with sound business principles, and, in the case of the DSIs, an equally clear and specific directive for carrying out that general directive.

PNGC also argues that BPA relies upon a methodology for making rates for DSI service that is about a quarter century old. *Id*. at 6. PNGC argues that the methodology was developed in 1985 at a time when BPA had a large surplus of power to sell, and sales to DSI customers were a businesslike solution to a problem that produced benefits for DSIs, BPA, and preference customers. *Id*. BPA disagrees with PNGC's implication that the statute is outdated. The plain language of the statute is controlling regardless of how many years ago the language was crafted and the conditions under which it is implemented.

To the extent that PNGC's argument should be considered beyond reference to the plain statutory language, BPA's history of implementation of the statutory commands is consistent with the view stated above. As BPA has stated before, section 7(c) essentially bars BPA from setting an IP rate that "recovers all the costs of serving DSI customers." WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 391. Prior to July 1, 1985, the IP rate was based on specific allocated costs. This changed on July 1, 1985. Now, section 7(c) does not contemplate the IP rate being established based on direct cost of service to the DSIs. Rather, it specifies that the IP rate is to be based on the applicable wholesale rate adjusted for the floor rate test, [the typical margin,] the value of reserves, and the section 7(b)(3) reallocation of the section 7(b)(2) rate protection amount. *Id*.

Furthermore, as stated by Staff, the IP rate methodology was established based on BPA's interpretation of section 7(c)(2). The 7(c)(2) directive explicitly identifies the considerations applicable to the IP rate. Burns *et al.*, WP-10-E-BPA-45, at 12.

BPA's methodology for determining the IP rate pursuant to section 7(c) is summarized above. It was established from BPA's interpretation of the Northwest Power Act without respect to the economic and operational conditions existing in 1984. Rather, BPA's methodology closely follows the expectations stated in 1979, five years prior to its first implementation and under much different economic and operational conditions than posited in PNGC's argument. The legislative history lays out the post-1985 IP rate methodology.

> The rate will be set at a level no less than that set for the year 1984-85 and that is equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial customers. This level is determined by applying a typical margin of cost ("markup" between the preference customers' retail industrial rates and their respective wholesale power costs) to the BPA wholesale rates to the preference customers for all power used to serve their industries. The rate is then adjusted for reserves.

S. Rep. No. 96-272, 96th Cong., 1st Sess. 59 (1979). This direction first mentions the floor rate test, that the IP rate is not to be below the level set for 1984-1985, and then establishes the basis for the IP rate as the retail rates charged by the public agencies to their industrial customers. This is determined by adding a "typical margin" to BPA's wholesale rates to the preference customers for all power used to serve their industries. The resulting rate is adjusted for the value of reserves. The legislative history continues describing this latter adjustment.

> The rates set [as] above are adjusted to reflect the credits for the value of power system reserves made available to the region's power system through the ability of BPA to interrupt service to the DSI loads. These credits to the DSI rate are then shared as a cost of reserves to all firm power sales, including that portion of the DSI load considered as not providing these reserves (currently 50 percent of the DSI load).

Id. at 60. This explains that the value of reserves is reflected as a credit to the IP rate. The cost of the credits is shared with all firm power sales, including any DSI load not providing the reserves. BPA has implemented this calculation by including the value of reserves together with the typical margin to derive what has been termed the "net margin." The legislative history continues with a discussion of how BPA is to recover the revenue difference between the revenues collected at the IP rate established under section 7(c) and the revenue requirement.

> Revenue adjustments will be made to all sales other than the DSI's to cover the difference after 1984-85 between revenues collected from the DSI rate and all other rates and the cost of power required to serve the regional loads.

Id. The report specifies that *all sales other than to the DSIs* are to make up the revenue underrecovery resulting from setting the IP rate lower than the costs allocated to DSIs. This is BPA's method, allocating the 7(c)(2) Delta to the rates for all other firm power sales, including the PF Preference rate. BPA's methodology does not allocate the underrecovery directly to the IP rate, but it does recognize that the amount of the underrecovery allocated to the PF Preference rate will increase that rate, requiring the IP rate to be reestablished to the higher PF Preference rate to maintain the equity between the IP rate and the PF Preference rate.

> Rate adjustments applicable in accordance with section [7(g)] are reflected … indirectly beginning in 1985-86 to the extent they modify the rates from BPA to public bodies and cooperatives for power that serves retail industrial customers.

Id. The report recognizes that costs are not directly allocated to the IP rate, including costs allocated pursuant to section 7(g). Rather, as section 7(g) costs are allocated to the PF Preference rate, the IP rate will be adjusted to maintain the section 7(c)(1) equity, thereby providing an indirect allocation of section 7(g) costs to the IP rate. BPA's methodology does not strictly conform to the report in this regard, because BPA does allocate costs to the DSIs pursuant to section 7(g) prior to the calculation of the 7(c)(2) Delta. However, the end result is the same as if BPA did not allocate costs to the DSIs pursuant to section 7(g); after the 7(c)(2) Delta calculation, all rate classes have the same allocated costs without respect to the manner in which costs are allocated prior to the 7(c)(2) Delta.

> Rate adjustments to recover revenues not recovered from the public body, cooperative, and Federal agency customers because of the preference customer rate limit … are reflected directly in the DSI rate.

Id. The report covers two aspects of the IP rate methodology in this statement. First, any section 7(b)(3) allocation of section 7(b)(2) rate protection to the DSIs is preserved through the application of section 7(c)(2). After the section 7(b)(2) rate test, the PF Preference rate is lowered by the amount of the rate protection. Because the PF Preference rate is lowered, the IP rate must be recalculated to maintain the section 7(c)(1) relative equity. This step is called the 7(b)(2) Industrial Adjustment 7(c)(2) Delta. However, the amount allocated to the DSIs pursuant to section 7(b)(3) is held aside in the calculation of the 7(b)(2) Industrial Adjustment 7(c)(2) Delta and is added back once the equitable IP rate has been reestablished.

The result of the application of the directions from the Senate Report is the IP rate. The methodology set forth in the Senate Report details the IP rate methodology that BPA established in 1984 and has continued to use since that time. Therefore, BPA sees no need to revise the IP rate methodology from that stated in the 1979 Senate Report just because conditions are different from 1984 when BPA first implemented the IP rate methodology.

Decision

BPA is required to set the IP rate consistent with statute, specifically section 7(c) of the Northwest Power Act, not on the basis of cost causation. BPA's IP rate methodology is consistent with statutes.

Issue 2

Whether the Northwest Power Act allows BPA to sell power to DSIs if doing so increases the PF Preference rate.

Parties' Positions

PNGC argues that nothing in the Project Act or the Northwest Power Act authorizes BPA to sell power to DSI customers when doing so increases the costs of serving preference customers' loads. PNGC Br., WP-10-B-PN-01, at 7.

BPA Staff's Position

Beginning in 1985, the application of section 7(c)(2) increased the PF rate; that is, the PF rate before the linkage with the IP rate was lower than after the linkage. Burns *et al.*, WP-10-E-BPA-45, at 13. This is the natural result of how the IP rate methodology works when the PF and IP rates are melded together. *Id*.

Evaluation of Positions

PNGC argues that BPA cannot increase the costs of serving preference customers' loads by incurring costs to serve DSIs. PNGC Br., WP-10-B-PN-01, at 7. However, as explained above, section 7(c) expressly requires a melding of the lower costs of power allocated to the PF Preference rate and the higher costs of power allocated to the DSIs. The Ninth Circuit, in *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037, 1045 (9th Cir. 2007), affirmed BPA's ability to augment the Federal base system for service to DSIs. The Court went on to state that

> Once FBS replacement resources were acquired, nothing in section 7(b)(1) precluded BPA from considering the costs of those replacement resources when calculating its preference rate, *even though BPA would not have incurred such costs absent its DSI contracts*. If FBS resources include both primary and replacement resources, and if BPA must recover "the costs of that portion" of FBS resources needed supply preference customer loads, then it follows that BPA may impose rates based on the average cost of FBS resources as a whole. This result is consistent with *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101 (9th Cir. 1984), which rejected the premise that preference customers were entitled "to purchase not just available power, but the cheapest available power." *Id*. at 1125.

Golden NW, 501 F.3d 1037, 1046 (9th Cir. 2007). The case before the Ninth Circuit was built on the same conditions that BPA faces now; the costs to serve DSIs increased the PF Preference rate. The *Golden NW* Court affirmed BPA's ratemaking that resulted in an increased PF

Preference rate by citing to *Central Lincoln*, which rejected the premise that preference customers were entitled to purchase not just available power, but the cheapest available power. The same conditions hold in the instant case. BPA has the statutory authority to include the costs of DSI service in the PF Preference rate.

Decision

The Northwest Power Act allows BPA to sell power to DSIs even if doing so increases the PF Preference rate.

Issue 3

Whether the relative costs of power are to be considered in addition to the typical margin when setting the IP rate.

Parties' Positions

PNGC argues that section 7(c)(1)(B) of the Northwest Power Act requires the Administrator to set rates for sales to DSI customers that are "equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial customers in the region." PNGC Br., WP-10-B-PN-01, at 7, *quoting* 16 U.S.C. § 839e(c)(1)(B). Section 7(c)(2) requires that this equitability determination be based not only on the Administrator's applicable wholesale rates to public body and cooperative customers and the typical margins included by those customers in their industrial rates. *Id*. at 7-8. PNGC argues that Congress's reference to relative costs in section 7(c)(2)(B) is in addition to the reference to the typical margin in section 7(c)(2). *Id*. at 9-10. PNGC argues that this requires BPA to take into account the costs of acquiring incremental supplies needed to provide any firm power service to DSI customers. *Id*. at 10.

BPA Staff's Position

PNGC misapplies the relative cost standard of section 7(c)(2)(B). Burns *et al*., WP-10-E-BPA-45, at 16. PNGC applies the relative cost standard as if it measured the difference in cost to BPA between costs allocated to the IP rate pool and the revenues received through the IP rate, which Staff found to be an incorrect application. *Id*. Staff believes that it is not appropriate to compare costs allocated to the IP rate pool when considering the cost of power for the public agencies. *Id*.

Evaluation of Positions

Section 7(c)(1)(B) of the Northwest Power Act directs BPA to set rates for sales to DSI customers that are equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial customers in the region. 16 U.S.C. § 839e(c)(1)(B). Section 7(c)(2) directs that this equitability determination shall be based upon BPA's applicable wholesale rates to preference customers and the typical margins included by preference customers in their retail industrial rates. The typical margin shall take into account the three factors set forth in subsections 7(c)(2)(A), (B), and (C) as related to the delivery of power to industrial customers.

As discussed above, the Transmission System Act directs that rates shall be fixed and established 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. Transmission System Act, section 9, 16 U.S.C. § 838g. PNGC attempts to marry the Transmission System Act diversified use standard with the Northwest Power Act section 7(c)(2)(A) required consideration of the comparative size and character of industrial loads served. PNGC Br., WP-10-B-PN-01, at 8. PNGC argues that DSI service does not provide a geographic diversified use, because BPA serves only three industrial loads, and the service is concentrated in two customers in one industry, aluminum smelting. *Id*. In contrast, PNGC notes, preference customers serve a myriad of diverse industrial loads spread throughout the length and breadth of the Pacific Northwest. *Id*. PNGC contends that BPA should take more account of the massive amounts of electric power consumed by aluminum smelter DSIs in order to conduct their operations, while providing a relatively small number of jobs. *Id*. The size and character of DSI loads in comparison to those of PF customers' industrial loads, and in light of BPA's statutory mission and mandates, show that it is inequitable for DSI loads to be subsidized by other regional industrial loads. *Id*. at 9.

PNGC's argument is inconsistent with the direction given in section 7(c)(2). Section 7(c)(2) directs how BPA is to determine that the IP rate is equitable in relation to preference customers' retail rates to industrial consumers. Equitability is established through the inclusion of the typical margin in the IP rate. There is no indication in section 7(c)(2) that the comparative size and character of the loads provision should be read in light of the Transmission System Act's diversified use standard. PNGC appeals to the concentration of aluminum smelter load compared to preference customer load. This argument wanes when viewed in light of the history of the Northwest Power Act.

The Northwest Power Act legislative history estimated preference customer total requirements load on BPA as 5,072 aMW in 1980-81 (PNUCC loads for Public Agencies plus Federal Agencies). S. Rep. No. 96-272, 96th Cong., 1st Sess. 65 (1979). For that same period, the total load for the 21 DSIs was estimated as 3,691 aMW, the majority serving 10 aluminum smelters. *Id*. At that time, DSIs accounted for 42 percent of the total load on BPA. In the instant proceeding, preference customer load on BPA is estimated as 7,415 aMW in FY 2010. Loads and Resources Study Documentation, WP-10-E-BPA-01A, at 10. In the Initial Proposal, the load for the three remaining DSIs is estimated as 402 aMW. Now, the DSIs account for 5 percent of BPA's total load. Yet, PNGC argues that service to this 5 percent of BPA's loads constitutes a threat to the widespread use standard in the Transmission System Act. If Congress had seen such a threat to this standard at the time of the drafting of the Northwest Power Act when DSI loads were 42 percent of the total load, there would have been some explicit tying of the two standards. BPA sees no such threat to the widespread use standard arising from a DSI service level around 5 percent of total loads. Rather, it appears that PNGC is attempting to create a new standard, unsupported by sound principles of statutory interpretation.

PNGC states that section 7(c)(2)(B) requires consideration of the *relative costs* of electric capacity, energy, transmission, and delivery facilities. PNGC Br., WP-10-B-PN-01, at 9 (emphasis by PNGC). PNGC states that Congress's reference to relative costs is in addition to the reference to the typical margin in section 7(c)(2). *Id*. at 9-10. PNGC draws the conclusion that this phrase requires BPA to take into account the costs of acquiring incremental supplies needed to provide any firm power service to DSI customers. *Id*. at 10. PNGC argues that the preference and priority obligation for service to preference customers and the mandate to promote widespread and diversified service *at the lowest prices to consumers* indicate that it would plainly be inequitable for BPA to force those utilities to subsidize rates for power sales to DSI customers. *Id*. at 10 (emphasis in original).

BPA does not read into section 7(c)(2)(B) the additive requirement that PNGC does. As noted above, "consumer" is defined as "any end user of electric power," and so the mandate to establish the lowest rates possible consistent with sound business principles is applicable to DSIs as well as preference customers' consumers. Moreover, the relative cost consideration is a part of the determination of the typical margin, not a vehicle for arbitrarily adding costs to the IP rate that are not included in the PF rate. Instead, the relative costs reference in section 7(c)(2)(B) relates to the power and transmission costs of the preference customers used in determining their retail rates to their industrial consumers as compared to the power and transmission costs BPA incurs to sell power to the preference customers, not the DSIs. The object of section 7(c)(2) is to compute rates to DSIs that are similar to those paid by industrial consumers of preference customers. This view is confirmed by the legislative history of the Northwest Power Act. The Senate Report describes the rate to DSIs after 1985 as:

> The rate will be set at a level no less than that set for the year 1984-85 and that is equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial customers. This level is determined by applying a typical margin of cost ("markup" between the preference customers' retail industrial rates and their respective wholesale power costs) to the BPA wholesale rates to the preference customers for all power used to serve their industries. The rate is then adjusted for reserves.

S. Rep. No. 96-272, 96th Cong., 1st Sess. 59 (1979). In this discussion, there is no reference to the costs that BPA incurs to serve the DSIs. Rather, it focuses on the costs included in rates to serve preference customers. The House Interior Report describes the IP rate as:

> After July 1, 1985, such rates are to be "equitable" in relation to certain specified retail industrial rates in the region; the method of determining the "equitable" rate is set forth in detail in subsection 7(c)(2).

H.R. Rep. No. 96-976, Pt. II, 96th Cong., 2nd Sess. 52 (1980). Thus, it is clear that the purpose of section 7(c)(2) is to describe how BPA is to determine the "equitable in relation" standard of section 7(b)(1)(B).

PNGC argues that section 7(c)(2)(C) requires consideration of direct and indirect overhead costs. PNGC Br., WP-10-B-PN-01, at 10. PNGC asserts that to avoid a duplicative or circular reading of this statutory language, section 7(c)(2)(C) should be understood to require BPA also to consider the high risk associated with serving aluminum smelters that have experienced declines in their credit ratings, claim to be losing money on their Northwest operations, regularly threaten to close their plants, and demand even more in the way of subsidies from BPA than what BPA initially proposed and what it is now paying them. *Id*.

Once again, PNGC focuses on the wrong entity when considering the direct and indirect overhead costs included in the typical margin. The typical margin is to take into account the direct and indirect overhead costs that preference customers include in their rates to their industrial consumers. It is not focused on BPA's costs associated with providing service to DSI load at the IP rate.

BPA reads section 7(c)(2) to lay out a specific method of determining the IP rate. The legislative history states that after June 1985 "the rate applicable to BPA direct service industrial customers (DSI's) will be based upon the retail rates applicable to industry served by BPA preference utility customers." S. Rep. No. 96-272, 96th Cong., 1st Sess. 56 (1979). It is not based on BPA's costs, except as such costs are included in the rates for preference customers.

Decision

The relative cost standard in section 7(c)(2)(B) refers to the costs included in the retail rates of industrial consumers of preference customers relative to the power costs of preference customers, not the power costs of BPA. It is measured by the typical margin, the mark-up from the power costs of preference customers to their rates to their industrial consumers. The relative cost standard does not refer to BPA's power costs allocated to DSIs prior to the application of section 7(c)(2) to determine the IP rate.

12.3 DSI Service Level

Issue 1

Whether BPA can assume in ratemaking that it may sell power to DSIs even though such assumption increases the PF Preference rate.

Parties' Positions

PNGC argues that BPA's organic statutes are not a springboard for expanded BPA discretion in determining whether to recover all costs of DSI service in the IP rates and whether to refrain from allocating any costs of DSI service to the rates paid by BPA's preference customers. PNGC Br., WP-10-B-PN-01, at 5. PNGC argues that any sales now to DSI customers, at the rates proposed by BPA, will increase BPA's net costs, and constitute a money-losing proposition rejected by the Ninth Circuit in *PNGC* as violating BPA's overarching statutory mandate. *Id*.

Snohomish PUD argues that because the IP rate is typically below the actual cost to supply power to the DSIs, the formula for calculating the IP rate is a specific exception to the general rule "that Congress intended BPA to operate as a business selling power for profit, not as a charitable institution distributing 'benefits.'" Snohomish Br., WP-10-B-SN-01, at 9-10, *quoting PNGC*, 550 F.3d 846, 876-877 (9th Cir. 2008).

BPA Staff's Position

Even in 1985, the application of section 7(c)(2) increased the PF rate; that is, the PF rate before the linkage with the IP rate was lower than after the linkage. Burns *et al.*, WP-10-E-BPA-45, at 13. This is the natural result of how the IP rate methodology works when the PF and IP rates are melded together. *Id*. at 13-14.

Evaluation of Positions

This issue is analogous to the question of whether costs incurred to serve the DSIs can be allocated to the PF Preference rate. As explained above in Issues 1 and 2 of section 12.2, the legislative history countenanced higher DSI costs than PF costs and yet melded the two, adjusted for the typical margin. The *Golden NW* court affirmed that BPA can augment the Federal system to enable service to DSIs and to include such costs in the PF Preference rate.

Decision

The decision whether BPA will sell power to DSIs is not a rate case issue; it will be decided in a separate public process. In setting rates, BPA will assume service to DSIs even if the costs of such service increase the PF Preference rate.

Issue 2

Whether the Ninth Circuit found selling below-cost power to DSIs invalid.

Parties' Positions

PNGC argues that the Ninth Circuit held in *PNGC* that the Transmission System Act mandate of "the lowest possible rates to consumers consistent with sound business principles" applied to BPA's sales to DSI customers. PNGC Br., WP-10-B-PN-01, at 4. PNGC argues that the Court found that helping the DSIs as a means to encourage the widest diversified us of electric power "does not justify a sale of power at below market *or* statutorily mandated rates." *Id., quoting PNGC*, 550 F.3d 846, 876 (9th Cir. 2008) (emphasis by the Court). PNGC argues that the Ninth Circuit addressed BPA's justifications for selling power below cost or paying cash subsidies to DSI customers during the FY 2007-2011 time period and found every one of them invalid. *PNGC*, 550 F.3d 846, 875-878 (9th Cir. 2008).

BPA Staff's Position

Because this is a legal issue, BPA Staff did not address the issue.

Evaluation of Positions

PNGC argues that the Ninth Circuit has invalidated BPA's ability to sell below-cost power to DSIs. PNGC Br., WP-10-B-PN-01, at 4. However, PNGC stretches the application of the *PNGC* opinion beyond its context. The Court had before it a situation where the rate was both below market *and* below the level of the IP rate. Its holding does not extend to an IP rate below market, but established pursuant to section 7(c). The "or" statement cited by PNGC is more specific than a general barring of sales to DSIs when such sales increase the PF rate.

PNGC states that the Ninth Circuit found that helping the DSIs as a means to encourage the widest diversified use of electric power "does not justify a sale of power at below market *or* statutorily mandated rates." *Id*. at 4, *quoting PNGC*, 550 F.3d 846, 876 (9th Cir. 2008) (emphasis by the Court). Here, PNGC draws too much from the Court's holding. While the Court was specific in its use of the word "or" in its criticism of BPA's use of the widespread use standard in reaching its decision to sell to the DSIs, the Court was very clear that criticism went to the rate that BPA applied to those sales.

> Because, by its own admission, BPA is not obligated to sell power to the DSIs, its decision to sell power voluntarily at a rate below what it is statutorily required to offer (i.e., the IP rate) *and* below what it could receive on the open market violates its statutory mandate to act in accordance with "sound business principles."

PNGC, 550 F.3d 846, 875 (9th Cir. 2008) (emphasis added). And again:

> When it committed itself to the particular monetary benefit provisions in the DSI contracts, BPA, in effect, agreed to supply some power to the DSIs — although not as much as they wanted — at a rate that is below both the market rate *and* the IP rate and could be as low as the PF rate. … BPA also concedes that its decision to sell power to the aluminum DSIs at below-market and below-IP rates will increase rates for its non-DSI customers.

Id. (emphasis added). Still again:

> Nor has the agency shown how offering the DSIs rates below the market rate *and* below what it is statutorily authorized to offer "further[s] BPA's business interests consistent with its public mission."

PNGC, 550 F.3d 846, 878 (9th Cir. 2008) (emphasis added). With regard to the sale to Port Townsend Paper through Clallam PUD, the Court held:

> We agree with Industrial Customers that the Clallam/Port Townsend contract rate is invalid because it commits BPA to sell power to Port Townsend (through Clallam) at a rate below both the market rate *and* the IP rate.

Id. (emphasis added). Finally, in its conclusion granting PNGC's petition, the Court reiterated its holding:

> We GRANT the Cooperative's and Industrial Customers' petitions as to the challenges they bring regarding BPA's statutory authority to offer the aluminum DSIs and Port Townsend (through Clallam) energy at rates below both the IP rate *and* the market rate, and REMAND to the agency for determination of the applicability of the agreements' severability and damage waiver provisions in light of our holdings.

PNGC, 550 F.3d 846, 882 (9th Cir. 2008) (emphasis added).

Therefore, while the Court used the word "or" in its holding on the widespread use standard, it is clear that its criticism of BPA's service to the DSIs was that the rates applied were below market *and* below the IP rate. The Court clearly did not set a standard that BPA must price power to the DSIs at the *higher* of the market rate *or* the IP rate, but allowed for the *lower* of the market rate *and* the IP rate. The central holding in *PNGC* is that the IP rate is the statutory rate applicable to

DSI sales and constitutes the "primary benefit" that DSIs receive under the Northwest Power Act. *PNGC*, 550 F.3d 846, 880-881 (9th Cir. 2008).

Decision

The PNGC holding by the Ninth Circuit did not bar selling power to DSIs at the statutory IP rate, whether or not such rate is below the incremental costs incurred to serve the DSIs.

Issue 3

Whether increasing BPA's costs due to DSI sales violates overarching statutory mandates, and whether setting an IP rate that loses money is in accordance with sound business principles.

Parties' Positions

PNGC argues that the IP rate will lead to sales at below market prices, a money-losing proposition, and do not conform to sound business principles or otherwise satisfy BPA's statutory obligations. PNGC Br., WP-10-B-PN-01, at 7; PNGC Br. Ex., WP-10-R-PN-01, at 7. PNGC argues that any sales to DSI customers at the rates proposed by Staff will increase BPA's net costs and constitute a money-losing proposition rejected by the Ninth Circuit in *PNGC* as violating BPA's overarching statutory mandate. PNGC Br., WP-10-B-PN-01, at 11.

BPA Staff's Position

Because this is a legal issue, BPA Staff did not address the issue.

Evaluation of Positions

PNGC argues that selling to DSIs at an IP rate below the cost of the incremental resources added to enable the DSI service constitutes a money-losing proposition. *Id*. However, as explained above, the establishment of the IP rate is directed by section 7(c) of the Northwest Power Act. *See* Issue 1 of section 12.2 above. That PNGC wishes to call this a money-losing proposition, a term it pulls from the *PNGC* opinion and uses out of context, does not make the IP rate contrary to sound business principles. The IP rate, set according to express congressional commands and results flowing from the lawful application of the section 7(c) rate directive, is consistent with sound business principles, regardless of how such results are characterized by those whose interests are not served by the result.

PNGC argues that the Ninth Circuit rejected BPA's rate to the DSIs because it constituted a money-losing proposition that violates BPA's overarching statutory mandate. *Id*. To be clear, the Ninth Circuit did not fault BPA's contract with the DSIs as a money-losing proposition; rather, the Court was critical of BPA's attempts to link below-cost sales to DSIs to the Residential Exchange Program, which has been characterized as a "money-losing program." *PNGC*, 550 F.3d 846, 877 (9th Cir. 2008) *quoting Aluminum Co. of America v. Central Lincoln Peoples' Util. Dist.*, 467 U.S. 380, 399 (1984), 104 S.Ct. 2472 (1984). The Court stated that the REP is a "specific exception," but that by subsidizing the DSIs' smelter operations *beyond what it is obligated* to do, BPA is simply giving away money. *PNGC*, 550 F.3d 846, 877 (9th Cir. 2008) (emphasis added). But the key phrase here is the "beyond what it is obligated to do." This shows that the Court recognized there is a potential level of subsidy that BPA is obligated to provide by adhering to the statutory rate directive. The Court defines this further when it gets to the crux of its opinion.

> Because, by its own admission, BPA is not obligated to sell power to the DSIs, its decision to sell power voluntarily at a rate below what it is statutorily required to offer (*i.e.*, the IP rate) *and* below what it could receive on the open market violates its statutory mandate to act in accordance with "sound business principles."

PNGC, 550 F.3d 846, 873-874 (9th Cir. 2008) (emphasis added). Here the Court defines the level of the allowed subsidy as the rate BPA is statutorily required to offer, *i.e.*, the IP rate. Thus, contrary to PNGC's assertion, the Ninth Circuit did not find that increasing BPA's costs to serve DSIs and then setting an IP rate that does not fully recover such costs violates overarching statutory mandates.

<u>Decision</u>

Selling to DSIs at the statutory IP rate is following the law. Following the law is a sound business principle.

<u>Issue 4</u>

Whether the Bonneville Project Act establishes a preference to BPA power that prohibits sales to DSIs, and whether Congress gave favor to end-use consumers of preference customers over DSIs.

<u>Parties' Positions</u>

PNGC argues that Congress specifically intended to favor end-use customers of preference utilities. PNGC Br., WP-10-B-PN-01, at 9. Moreover, PNGC argues, the legislative history of the Project Act shows that Congress intended to favor end-use customers of preference utilities when compared specifically to aluminum smelters. *Id*., *citing* 1937 Congressional Record—House, at 7606-7609. PNGC states that Congress rejected an amendment that would have allowed Alcoa to purchase all of the output of the Bonneville Project. PNGC Br., WP-10-B-PN-01, at 4. Consistent with this intent, PNGC argues, Congress enacted public preference and priority provisions. *Id*., *citing* Project Act, section 4, 16 USC § 832c. PNGC argues that Congress authorized BPA to construct a transmission system to promote geographically widespread service and end-use diversity and directed BPA to set its rates "with a view to encouraging the widest possible diversified use of electric energy." PNGC Br., WP-10-B-PN-01, at 4, *quoting* Project Act, section 6, 16 U.S.C. § 832e. PNGC argues that BPA retains a statutory obligation to serve preference and investor-owned utility customers but has no obligation to serve DSI customers. *Id*. at 5. PNGC concludes that preserving the lowest possible PF rates for the benefit of consumers throughout the region and providing residential exchange benefits in conformity with sections 5(c) and 7(b) of the Northwest Power Act, 16 U.S.C. §§ 839c(5)(c) and 839e(b) are consistent with BPA's statutory mandates. *Id*.

BPA Staff's Position

Because this is a legal issue, BPA Staff did not address the issue.

Evaluation of Positions

The crux of the PNGC argument appears to be that public preference creates a preference to price in addition to supply. 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. PNGC cites statutory authority for the proposition that BPA must sell power in compliance with public preference. BPA agrees. However, the arguments asserted by 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 said 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 Co. of America, et al. v. Central Lincoln Peoples' Utility District, et al.*, 467 U.S. 380, 381 (1984), 104 S.Ct. 2472 (1984). 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 (9th 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 is sufficient supply to meet both preference customer load and DSI load. 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. The *Golden NW* Court affirmed BPA's right to augment the Federal base system to meet its contractual commitments, including sales to the DSIs. *See* Issue 2, section 12.2 above. BPA does not make power sales to non-preference customers if that would preclude BPA from meeting the load of 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*, the Court rejected an argument that "preference entitles its members to purchase not just available power, but the cheapest available power." 735 F.2d 1101, 1125 (9th Cir. 1984). In *Central Lincoln*, the Court also 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*, 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." 781 F.2d 163, 166 (9th Cir. 1986). As such, there are no cases cited by PNGC, and none BPA is aware of, supporting the argument that there is a preference to price.

In summary, BPA has not neglected its obligations under statutory provisions providing preference and priority rights. BPA has properly allocated the costs of the FBS and set the DSI rate in accordance with statutory directives.

<u>Decision</u>

The Project Act facilitated sales to DSIs; it does not prohibit such sales. BPA's governing statutes do not establish a preference to price and do not preclude BPA from acquiring power to serve DSIs and including such costs in preference customer rates.

<u>Issue 5</u>

Whether DSI access to wholesale power markets makes them better off than other industrial consumers, making it inequitable for other consumers to pay a portion of DSI service costs.

<u>Parties' Positions</u>

PNGC argues that the DSIs have direct access to wholesale power markets and in that sense are better off than industrial consumers of BPA's investor-owned utilities. PNGC Br., WP-10-B-PN-01, at 9. PNGC notes that market prices have in the past been well below BPA's rates. *Id*. Market prices are now well above BPA's rates, and paying market prices is not what the DSIs now want to do. *Id*. PNGC concludes that because Congress specifically intended to favor end-use consumers of preference utilities, it is inequitable now for DSI loads to be subsidized by other regional industrial loads. *Id*.

<u>BPA Staff's Position</u>

This is a new issue not raised before the Initial Briefs. BPA Staff took no position on this issue.

<u>Evaluation of Positions</u>

PNGC argues that the DSIs have direct access to wholesale power markets and in that sense are better off than industrial consumers of BPA's investor-owned utilities. PNGC Br., WP-10-B-

PN-01, at 9. BPA sees no basis for PNGC to compare the DSIs to the industrial consumers of investor-owned utilities. BPA does not serve any IOUs; nor do the industrial consumers of IOUs receive Residential Exchange Program benefits. Therefore, based on the context of PNGC's argument, BPA offers the following argument assuming that PNGC meant to refer to the industrial consumers of *consumer-owned* utilities. BPA provided this argument first in the Draft ROD, stating that if BPA had made an incorrect assumption, PNGC had an opportunity in its Brief on Exceptions to better explain its investor-owned utility argument. PNGC did not avail itself of that opportunity.

BPA disagrees with PNGC that Congress specifically intended to favor end-use consumers of preference utilities to the exclusion of the DSIs. As explained in Issue 4 of this subsection, above, neither the Project Act nor any other statute grants preference to price to preference customers. But Congress did attempt to fashion an equal access to price for DSIs and industrial consumers of preference customers. Section 7(c)(1) establishes that the IP rate is to 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). This equity is defined in section 7(c)(2) as "…the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates…." *Id*. at § 839e(c)(2). Therefore, quite the opposite of establishing a price preference for the industrial consumers of preference customers, the IP rate establishes a rate equity for the DSIs. Such equity was not conditioned in the Northwest Power Act on whether the DSIs have access to wholesale power markets.

Decision

The fact that DSIs have access to wholesale power markets, in contradistinction to retail industrial consumers served by preference customers, does not require BPA to alter its IP rate methodology to be inconsistent with section 7(c).

Issue 6

Whether the size and character of DSI load create inequities.

Parties' Positions

PNGC argues that the size and character of DSI loads, in comparison to those of PF customers' industrial loads, and in light of BPA's statutory mission and mandates, show that it is inequitable now for DSI loads to be subsidized by other regional industrial loads. PNGC Br., WP-10-B-PN-01, at 9.

BPA Staff's Position

The typical margin takes into account the character of service to the DSIs compared to the industrial customers of the public agencies and the relative costs incurred by the public agencies to serve their industrial customers, including power, transmission, delivery facility, and direct and indirect overhead costs. Burns *et al.*, WP-10-E-BPA-45, at 14-15.

Evaluation of Positions

PNGC argues that the size and character of DSI load create inequities. PNGC Br., WP-10-B-PN-01, at 9. BPA does not agree. In the Initial Proposal, preference customer load on BPA is estimated as 7,415 aMW in FY 2010. Loads and Resources Study Documentation, WP-10-E-BPA-01A, at 10. If the retail industrial consumer loads of preference customers comprise about 33 percent of their loads (based on EIA-reported 2007 sales data), then such industrial consumer loads would comprise about 2,447 aMW of BPA-served load. The loads for the three remaining DSIs are estimated at 402 aMW. Now the DSIs account for 5 percent of BPA's total load, and the DSI load would be about 16 percent of the size of the industrial consumer loads of preference customers. PNGC apparently argues that it is the potential of BPA service to 402 aMW of DSI load that would create inequities to the 2,447 aMW of retail industrial consumer loads of preference customers.

There is no basis to conclude that a total DSI load of 402 aMW would raise a statutory concern of inequities when the DSI load was expected to be 3,700 aMW when the Northwest Power Act was drafted. Such concern was not evident in the statutory language, nor in the legislative history of the Northwest Power Act, the most recent legislation addressing the relative equities between preference customers and DSIs. Therefore, BPA cannot draw such a conclusion today when none existed at the time the Northwest Power Act was drafted and enacted.

Decision

The size and character of the DSI load do not create inequities.

Issue 7

Whether including the costs of BPA sales of industrial power in the PF Preference rate leads to inequitable subsidies.

Parties' Positions

PNGC argues that it is neither BPA's responsibility nor a proper use of its discretion to subsidize the DSIs at the expense of end-use consumers served by preference utilities in this region. PNGC Br., WP-10-B-PN-01, at 8-9; PNGC Br. Ex., WP-10-R-PN-01, at 7. PNGC also argues that given BPA's preference and priority obligation for service to end-use customers of publicly and cooperatively owned utilities in this region and its mandate to promote widespread and diversified service at the lowest prices to consumers, it would plainly be inequitable for BPA to force those utilities to subsidize rates for power sales, or pay the cost of cash payments, to DSI customers. PNGC Br., WP-10-B-PN-01, at 10. PNGC states that the relative cost of serving DSI customers at subsidized rates is too high. *Id.*

BPA Staff's Position

Because this is a legal issue, BPA Staff did not address the issue.

Evaluation of Positions

The past several years have seen endless debate among the parties regarding whether service to DSIs constitutes a "subsidy." Yet the issue of whether such service does or does not amount to a subsidy provides no legal standard or even useful guidance to which BPA could or should respond with regard to establishing rates.

The Ninth Circuit recognized that the IP rate, as mandated by Congress, might itself lawfully be characterized as providing some level of subsidy to the DSIs. The Court refers to the IP rate as the rate that BPA "is statutorily required to offer" and states that it reflects "the primary benefit that the class of DSI customers receives under the [Northwest Power Act]…." *PNGC*, 550 F.3d 846, 880-881 (9th Cir. 2008). Further, the Ninth Circuit invalidated the monetized FPS surplus sale, at least in part, because BPA was "subsidizing the DSIs' smelter operations beyond what it is obligated to do," *i.e.*, beyond what is provided for by Congress through the IP rate directive. *PNGC*, 550 F.3d 846, 877 (9th Cir. 2008) (emphasis added). Thus, if proper application of the IP rate directives results in a benefit to the DSIs, that is simply a consequence of the Northwest Power Act, not an illegal subsidy.

The evidence relied upon by BPA in this proceeding must be guided by the legal standards articulated in BPA's enabling statutes as interpreted by the court. There is no such applicable standard to apply with regard to the "subsidy" issue, and PNGC's incantation of the word does not provide one. The word itself is capable of multiple interpretations, and these are generally applied based on the "eye of the beholder" rather than any rigorous logical standards. Simply put, BPA is not required by statute, or any court's interpretation thereof, to make a finding that rates do or do not constitute a "subsidy," and neither would BPA have authority simply to declare otherwise legally proper rate levels invalid based on allegations that they constitute a "subsidy."

Finally, it must be noted that the level of the IP rate is substantially higher than the rates to the industrial consumers of preference customers, because the IP rate also bears a section 7(b)(3) allocation of the section 7(b)(2) rate protection costs. In the Initial Proposal, the PF Preference rate at 100 percent load factor was $28.04/MWh; adding the typical margin of $0.57/MWh resulted in an average retail industrial rate of $28.61/MWh. By comparison, the average IP rate in the Initial Proposal was $36.37/MWh, because it included a 7(b)(3) Supplemental Rate Charge of $7.74/MWh.

Decision

Including the costs of BPA sales to DSIs in the PF Preference rate does not constitute an inequitable subsidy.

Issue 8

Whether selling power to DSIs constitutes choosing winners and losers in the PNW economy, and whether selling power to DSIs constitutes favoring aluminum smelter jobs over other jobs.

Parties' Positions

PNGC argues that BPA has no business interest in choosing which regional end-use customers will be winners and losers in this distressed economy. PNGC Br., WP-10-B-PN-01, at 10. PNGC claims that the relative cost of serving DSI customers at subsidized rates is too high. *Id*. PNGC argues that BPA will realize no economic benefit, and it is an unsound business decision for BPA to choose to do so. *Id*. PNGC states that subsidizing the DSIs reflects impermissible favoritism and will worsen an already dire economic climate. PNGC Br. Ex., WP-10-R-PN-01, at 7.

PPC *et al.* object to BPA's decision to favor aluminum smelter jobs over the many jobs within BPA customers' service territories. PPC *et al.* Br., WP-10-B-JP11-01, at 6. PPC *et al.* find the proposal that BPA voluntarily incur costs even beyond service at the standard IP rate even more defective. *Id*.

BPA Staff's Position

BPA Staff did not address the issue.

Evaluation of Positions

PNGC argues that BPA's choosing to serve DSIs constitutes picking winners and losers in the Pacific Northwest economy. PNGC Br., WP-10-B-PN-01, at 10. PPC *et al.* argue that BPA's choosing to serve DSIs constitutes favoring aluminum smelter jobs over other jobs. PPC *et al.* Br., WP-10-B-JP11-01, at 6. BPA disagrees. Section 7(c) of the Northwest Power Act establishes rate equity between the rates of preference customers to their industrial consumers and BPA's IP rate to DSIs. This equity is explained in more detail in Issue 1 of section 12.2 above. Establishing an IP rate that is determined as being equitable in relation to the preference customers' retail rates to industrial consumers puts all of these industries on an equal basis in the rates that they pay. This cannot be construed as favoring one industry, aluminum, over others, but rather, following the law.

If the PNGC/PPC *et al.* logic is followed, then it is equally true that PNGC and PPC *et al.* are attempting to pick winners, or favor their industrial jobs, by denying the DSIs access to the statutorily equivalent industrial rate.

The legislative history confirms BPA's position that after June 1985 "the rate applicable to BPA direct service industrial customers (DSI's) will be based upon the retail rates applicable to industry served by BPA preference utility customers." S. Rep. No. 96-272, 96th Cong., 1st Sess. 56 (1979). Establishing a rate in this manner cannot be construed as favoritism to one industry over another.

PNGC argues that service to the DSIs will worsen an already dire economic climate. PNGC Br. Ex., WP-10-R-PN-01, at 7. BPA disagrees. The evidence on the record shows that there is the potential for a small, genuine economic benefit to the region in the form of a net employment gain resulting from service to the DSIs. Burns *et al.*, WP-10-E-BPA-49, at 3 and Exhibit C. Rather than worsening the regional economy, service to the DSIs offers the potential for an improvement to the regional economy.

Decision

Any decision regarding service to DSIs at the IP rate is likely to result in perceived winners and losers. The test cannot be whether there will be winners and losers. The correct test is whether BPA's actions and rates are consistent with the law. Decisions to serve DSIs are not made in rate proceedings. The IP rate is established consistent with statute.

Issue 9

Whether sales to DSIs must have clear showing of offsetting benefits.

Parties' Positions

NRU states that it cannot support decisions that impose the costs of serving the DSIs on preference customers without a clear showing that preference customers will receive completely offsetting benefits from those decisions. NRU Br., WP-10-B-NR-01, at 8. NRU argues that such demonstration has not been made in this rate proceeding. *Id.*

BPA Staff's Position

Issues associated with actual DSI service will be resolved in a process outside of this rate proceeding. Bliven and Lefler, WP-10-E-BPA-10, at 11.

Evaluation of Positions

NRU argues that BPA has not made a clear showing of offsetting benefits from DSI service in this proceeding. NRU Br., WP-10-B-NR-01, at 8. However, the NRU argument goes to the merits of whether BPA decides to serve DSIs, not what the level of rates should be. This proceeding is a ratesetting exercise; it is not the proceeding to demonstrate whether there are offsetting benefits from DSI service.

Decision

BPA is not deciding whether or not to serve DSIs in this rate proceeding. Whether there is a clear showing of benefits from DSI service is not a rate case issue.

Issue 10

What level of service to DSIs BPA should assume in setting rates.

Parties' Positions

Alcoa argues that BPA still has contracts in place with the DSIs with contracted loads of 560 aMW, and the Block Power Sales Agreements ("Agreement") with BPA were intended to be effective from October 1, 2006, through September 30, 2011. Alcoa Br., WP-10-B-AL-01, at 7. Alcoa argues that the Ninth Circuit did not invalidate the power sales provision of the Agreement, and the Court did not find that the power sales provisions were not severable. *Id.* Thus, under the terms of the Agreement, Alcoa argues, the surviving power sale provisions (including the 560 aMW aggregate DSI Demand Entitlement found in Exhibit E of the Agreement) remain in place. *Id*. Alcoa maintains that BPA therefore has the right and obligation to serve Alcoa with the 320 aMW in the original Exhibit E of the Agreement and the Unused Benefit Amount equivalent of 69.6 aMW, for a total of 389.6 aMW for Alcoa alone. Therefore, Alcoa states, BPA should not base its revenue requirement on the assumption that it will serve only one potline of DSI load at each smelter due to foreseeable aluminum prices during the rate period, or otherwise restrict in the rate schedule the amount of load to be served. *Id*. Instead, Alcoa states, BPA should decide the amount of load to be served under the variable rate in its contract negotiations. *Id*.

PPC *et al.* express concern that BPA's forecast of service to DSIs was not based on reasonable load forecasting methods, which could result in preference customers' rates being set higher than necessary. PPC *et al.* Br., WP-10-B-JP11-01, at 3. PPC *et al.* also express concern that there were certain financial risks associated with BPA's assumptions about DSI service. *Id*.

PNGC opposes the costs of any service to DSIs being included in the PF Preference rate. PNGC Br., WP-10-B-PN-01, at 2-3. PNGC argues that the risk to BPA and its preference customers, who would be forced to pay the costs, is not acceptable. *Id*. PNGC states that serving the DSIs is unsound as a matter of policy, equity, economics, sound business principles, and law. *Id*. PNGC argues that the depth and duration of the economic recession call for BPA to take additional steps to reduce or eliminate the increase in wholesale power rates. PNGC Br. Ex., WP-10-R-PN-01, at 6. PNGC states that eliminating subsidized service to the DSIs, no matter how moderate, is a measure BPA should take now. *Id*. at 6-7. PNGC asserts that this subsidy can no longer be afforded. *Id*. at 7.

NRU proposes that the PF rate could be lowered by removing the cost of serving the DSIs. NRU Br. Ex., WP-10-R-NR-01, at 2.

BPA Staff's Position

In the Initial Proposal, BPA Staff assumed that DSI smelter loads placed on BPA would total 385 aMW. Burns *et al.*, WP-10-E-BPA-45, at 23. This assumption was a placeholder, which was chosen to not disrupt the ratemaking process given the timing of PNGC opinion. *Id*.

Evaluation of Positions

Staff expected that a decision on the FY 2010-2011 level of DSI service would be made before the Final ROD was published. As of this time, however, a decision has not yet been reached. Therefore, a best estimate of the level of DSI service needs to be made so that rates can be determined. BPA agrees with Alcoa that the determination of the level of service is a contract matter, and a separate process is underway to allow BPA to receive comment from all stakeholders to determine the contract amount. The decision for ratesetting purposes, while not binding on the decision in the contract process, needs to take into account the likely costs and risk attendant to the forthcoming decision.

Using an assumption of 385 aMW of DSI aluminum service in the ratesetting process would provide a reasonable balance between 1) setting a rate too low and jeopardizing cost recovery should the final decision be higher, and 2) setting a rate too high and collecting more revenues than required to meet the costs incurred for DSI service.

Also, it is reasonable to assume service to DSIs in the ratesetting process despite its impact on the level of the PF rate. BPA understands that the regional economy has been hit hard at this time and that the level of its rates is an important factor in the health of the economy. However, preference customers are calling to help the economy in certain areas, *i.e.*, those served by preference customers, at the expense of the economy in other areas, *i.e.*, those where the DSIs operate, is not a choice that BPA should be making. If BPA sets the PF and IP rates based on its statutory authorities, it accomplishes the balance designed by Congress in equating the rates to industries served by BPA—the DSIs—and the rates to industries served by BPA's preference customers. Rates set at such levels do not guarantee economic survival by any industry, but they do offer all affected industries access to Federal power and let other factors determine their survival.

PNGC's other issues are dealt with in the preceding discussions in section 12.2 and 12.3.

Decision

BPA will set rates based on 385 aMW of DSI aluminum service and 17 aMW of DSI non-aluminum service. This level of DSI service strikes a reasonable balance between ensuring cost recovery and the lowest possible rates consistent with sound business principles.

12.4 DSI Risk Mitigation

Issue 1

Whether BPA should establish an Industrial Cost Adjustment Clause (ICAC).

Parties' Positions

WPAG argues that the proposed ICAC is both untimely and ill-considered and strongly urges BPA not to adopt it. WPAG Br., WP-10-B-WG-01, at 23; Mundorf, Oral Tr. at 233-234.

PPC *et al.* do not support any mechanism that passes through the costs of serving the DSIs to preference customers. PPC *et al.* Br., WP-10-B-JP11-01, at 3. PPC *et al.* also state that if BPA were to adopt the ICAC, BPA may view this adjustment mechanism as a substitute for placing hard limits on the costs it incurs in serving the DSIs or providing them with payments. *Id.*

Cowlitz states that the ICAC is just a bad idea. Murphy, Oral Tr. at 116.

Snohomish opposes the ICAC. Kallstrom, Oral Tr. at 125.

ICNU argues that the way that the ICAC has been offered is a classic false dilemma for preference customers because it provides a number of options, none of which truly benefits preference customers. Sanger, Oral Tr. at 206.

BPA Staff's Position

BPA Staff proposed the ICAC as a means to adjust cost-based rates based on actual DSI service levels and resultant costs. Burns *et al.*, WP-10-E-BPA-45, at 47. The ICAC would adjust rates each month based on smelter operations based on then-current knowledge or expectations about DSI service conditions before the beginning of each month. *Id*. at 24-25.

Evaluation of Positions

BPA is faced with difficult decisions in setting the IP rate, because the level of service to be offered to DSIs is unknown, as are the actual operating levels of the smelters. Assessing the risks attendant to a contract negotiation is a difficult matter, because the variables are more dependent upon human interactions and decisions than normal operational decisions.
In assessing the risk of smelter operations, one can assume that aluminum company decisions will be rational when considering all of the input factors, such as the costs of inputs to the production of aluminum and the price at which the output can be sold. Contract negotiations are much more complex, because they involve long-term expectations of a number of different considerations.

The timing of the *PNGC* opinion, immediately before the filing of the Initial Proposal, left Staff insufficient time to develop the risk assessments that would normally accompany a rate proposal. The ICAC was proposed during the rate proceeding as a possible risk mitigation tool that would address the unknowns in a prompt and specific manner. One of the chief concerns raised by parties in response to both the level of service issue and the variable IP rate issue was how to ensure that BPA's rate was not set too high if BPA assumed a certain level of service and then DSIs did not operate at that level. Under such a condition, BPA would not be incurring the level of costs expected when rates were established, thereby overcollecting its expenses. The ICAC was a tool that would have rebated any excess revenues to BPA's ratepayers in a timely manner.

However, BPA understands public power's concerns and opposition to the ICAC. Allowing the PF Preference rate to continually vary each month depending on aluminum smelter operating decisions is of great concern to public power. BPA recognizes that generally BPA is in a better situation than its customers to absorb different kinds of short-term risks through the use of various liquidity tools available to BPA. If BPA absorbs the risk, it can then spread the cost of such risk through time to allow a more orderly and considered inclusion of the costs of such risks in BPA's rates.

Because of the great concern and opposition to the ICAC, BPA declines to implement this risk mitigation tool during FY 2010-2011.

Decision

BPA will not adopt the Industrial Cost Adjustment Clause. All other issues concerning the ICAC are hereby rendered moot.

12.5 Variable IP Rate

Issue 1

Whether BPA should offer an interim variable IP rate for DSI aluminum smelters.

Parties' Positions

Alcoa proposed a variable IP rate that would permit the upper limit (the ceiling) and the lower limit (the floor) of the DSI rate to range from $15 per MWH above the standard IP rate to $15 per MWH below the standard IP rate. Alcoa Br., WP-10-B-AL-01, at 9. Alcoa believes that limiting the variable IP rate to BPA's proposed +/- $8.00/MWh swing would cause Northwest smelters to shut down completely if aluminum prices were expected to remain at low levels for an extended time. *Id.* at 10. However, Alcoa understands that BPA and its customers would like to have a separate process to further consider the long-term variable rate, and Alcoa commits to work with BPA and the other stakeholders in a separate (but timely) process to develop a long-term variable rate approach. *Id.*

PPC *et al.* oppose the variable IP rate. PPC *et al.* assert that BPA's decision to offer the DSIs a reduced rate is best viewed as a decision to voluntarily incur losses, for nothing in return. PPC *et al.* Br., WP-10-B-JP11-01, at 8-9.

Snohomish argues that the variable IP rate proposals do not follow the congressionally mandated IP rate formula. Snohomish Br., WP-10-B-SN-01, at 11. Because Congress has so clearly spoken on this issue, Snohomish states, BPA lacks the discretion to stray from the formula contained in section 7(c). *Id.* Snohomish argues that BPA lacks the ability to determine the cost and other impacts associated with adoption of a variable IP rate, and thus lacks the information necessary to determine that adoption of a variable rate is in the best interests of BPA and its preference customers. *Id.* at 16.

WPAG argues that BPA's proposed variable IP rate suffers from many of the same infirmities as the original Alcoa variable IP rate proposal, and should not be adopted. WPAG Br., WP-10-B-WG-01, at 19.

BPA Staff's Position

In response to an Alcoa proposal for a variable IP rate, BPA Staff proposed a more conservative FY 2010 variable DSI rate to improve the chances of the two remaining DSI smelters operating at least one potline during this time of low aluminum prices. Burns *et al.*, WP-10-E-BPA-45, at 47. Part of that proposal included quickly commencing a separate rate proceeding regarding establishment of a long-term variable IP rate to enable sufficient time for needed analysis and adequate review and input by interested rate case parties. *Id.* In addition, BPA's proposal would true up any differences between the FY 2010 and long-term variable IP rate. *Id.*

Evaluation of Positions

In its direct testimony, Alcoa proposed that BPA adopt a variable IP rate for aluminum smelters much as BPA did in 1986. Alcoa Br., WP-10-B-AL-01, at 9. A variable IP rate would adjust the

IP rate based on the spot price of aluminum, as measured over a time period on the London Metals Exchange. BPA adopted the Variable Industrial Power (VI) rate in 1986 as a means to increase aluminum smelter loads and to make power rates to the smelters more predictable and stable to allow the smelters to make long-term investment decisions,. *See, generally,* Variable Industrial Power Rate Proposal Administrator's Record of Decision, VI-86-A-02. The VI rate operated such that the rate would decrease when aluminum prices decreased and increase when aluminum prices increased. The VI rate was tied to the IP rate such that when aluminum prices were in the middle of a "normal" range, the VI rate would equal the IP rate.

In this proceeding, Alcoa has proposed a variable IP rate similar to the VI rate. The key feature of Alcoa's proposal is that the variability of its proposed rate is a range of plus or minus $15/MWh from the IP rate, depending upon the price of aluminum. Alcoa Br., WP-10-B-AL-01, at 9.

In rebuttal testimony, Staff countered Alcoa's proposal with an alternative variable IP rate, with the variability in a range of plus or minus $8/MWh from the IP rate. Burns *et al.*, WP-10-E-BPA-45, at 43-44. Staff expressed concern over the inability to test the parameters of Alcoa's proposal in the short amount of time allowed in the instant proceeding. *Id.* at 38-41. Therefore, Staff proposed that the rate be established on an interim basis, subject to true-up to a long-term variable IP rate that would be examined in a subsequent section 7(i) proceeding. *Id.* at 41-43.

While rate case parties certainly have procedural rights to challenge BPA's rate proposals and offer modifications in rate proceedings, generally BPA prefers to consider discretionary rate design changes that affect the manner by which costs are recovered from customers through informal workshops with representatives from all customers, thus allowing careful consideration of proposals and a free flow of ideas. BPA is concerned that all of its customers have not had opportunity to fully consider the effects and ramifications of a variable rate in this proceeding. A subsequent section 7(i) process would allow for such a process. BPA prefers a more considered approach to rate design changes, unless the immediacy of a problem does not allow time for a more deliberate consideration.

The parameters of a variable IP rate are very important. Deciding at what point a variable IP rate departs, either above or below, the standard IP rate is critical to ensuring that a variable IP rate would recover at least as much revenues as the standard IP rate over a period of years. BPA is concerned that the proposed parameters for a variable IP rate, whether Alcoa's proposed rate or Staff's proposed rate, are set appropriately, and that there is insufficient information on the record to ensure that. A sufficient examination of this issue has not occurred in this proceeding.

Furthermore, BPA is very concerned about cost recovery during the FY 2010-2011 rate period. Although Staff's proposal for a letter of credit from Alcoa addresses cost recovery from Alcoa, it does not fully address cost recovery in total for BPA, because the operating levels of the smelters during the rate period are unknown. The letters of credit would ensure that the smelters paid the difference between the variable IP rate and the standard IP rate if the smelters decided not to purchase under the long-term variable IP rate. The letters of credit did not address revenues not received from smelters if they did not operate at the levels contemplated in setting rates, however. The proposed ICAC would have addressed much of the total cost concerns, but such concerns remain as a result of BPA's decision not to adopt an ICAC.

For the reasons stated herein, a variable IP rate presents too many concerns and uncertainties to be implemented at this time.

Decision

At this time, BPA will not adopt a variable IP rate for the FY 2010-2011 rate period. Given the timing of when the issue was raised in this rate proceeding, there was inadequate opportunity to fully address the issues that are necessary to address.

Issue 2

Whether other arguments against a variable IP rate need to be addressed given the decision to not adopt a variable IP rate.

Parties' Positions

In the briefs of various preference customers, a number of issues regarding the variable IP rate proposal were raised. These issues include:

- *Whether a variable IP rate below the statutory IP rate is allowed.*
- *Whether a variable IP rate that is below market or below the standard IP rate is consistent with statute.*
- *Whether a variable IP rate is in BPA's business interest.*
- *Whether BPA gets anything in return for a variable IP rate.*
- *Whether an interim variable IP rate constitutes a loan of money.*
- *Whether a variable IP rate is at best a cost shift, and at worst a permanent and unlawful cost increase to preference customers.*
- *Whether a variable IP rate would result in continued revenue loss.*
- *Whether a variable IP rate imposes a cost of a subsidy on other customers.*
- *Whether a variable IP rate is allowable in situations unlike those present in Portland Gen'l.*
- *Whether a variable IP rate ignores plain Congressional direction.*
- *Whether a variable IP rate repeats the error found by the Ninth Circuit.*
- *Whether a variable IP rate would result in a rate lower than the preference customers' rates.*
- *Whether the theoretical possibility of a variable IP rate true-up is too remote and too tenuous.*
- *Whether a variable IP rate is likely to produce less revenue than market rates.*
- *Whether the economics of a variable IP rate are a zero-sum game and result in no net gain in PNW employment.*
- *Whether BPA and parties could conduct adequate analysis and review of the proposed variable IP rate.*
- *Whether a follow-on rate proceeding is not justified because BPA lacks a power surplus.*
- *Whether a follow-on rate proceeding should be conducted in the face of heavy workloads during a period with an overloaded agenda.*

Decision

Because BPA has decided not to adopt a variable IP rate, the foregoing issues are moot. They will not be addressed in this ROD.

Issue 3

Whether BPA should commit to conducting another rate proceeding for purposes of establishing a long-term variable IP rate.

Parties' Positions

PPC *et al.* state that BPA should avoid conducting such a proceeding. PPC *et al.* Br., WP-10-B-JP11-01, at 9; PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 3-4. Under the circumstances facing the agency at this time and in the foreseeable future, PPC *et al.* argue, a variable rate for the DSIs will result, at best, in a problematic shifting of costs between customers and, at worst, a permanent and unlawful cost increase to BPA's preference customers. PPC *et al.* Br., WP-10-B-JP11-01, at 9.

WPAG is strongly opposed to conducting another section 7(i) proceeding. WPAG Br., WP-10-B-WG-01, at 23.

Alcoa states that it understands that BPA and its customers would like to have a separate process to further consider the long-term variable rate, and Alcoa commits to work with BPA and the other stakeholders in a separate (but timely) process to develop a long-term variable rate approach. Alcoa Br., WP-10-B-AL-01, at 10.

BPA Staff's Position

Staff proposed to quickly commence a separate rate proceeding regarding establishment of a long-term variable IP rate to enable sufficient time for needed analysis and adequate review and input by interested rate case parties. Burns *et al.*, WP-10-E-BPA-45, at 47.

Evaluation of Positions

Because BPA is not adopting a variable IP rate for FY 2010 at this time, it is not necessary at this time to commit to another section 7(i) rate proceeding to develop a long-term variable IP rate. Should contract negotiations with the aluminum smelters lead BPA to conclude that a long-term variable IP rate is warranted, a section 7(i) rate proceeding can be commenced. Such a determination does not need to be made at this time.

Decision

BPA will not commit at this time to conduct another section 7(i) rate proceeding to develop a long-term variable IP rate. BPA does, however, remain open to considering a long-term variable IP rate established through a separate 7(i) process. An existing public process being *conducted this summer regarding future DSI service levels and contracts will help inform whether such a rate should be developed.*

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13.0 INTER-BUSINESS LINE COST ALLOCATIONS

13.1 Introduction

The purpose of the inter-business line cost allocations is to assign certain power costs from Power Services to Transmission Services consistent with the principle of cost causation. Many products Transmission Services provides to its customers require generation to supply both power and capacity. This generation is referred to as generation inputs, and these inputs are necessary for most of the ancillary and control area services that Transmission Services provides under its Open Access Transmission Tariff (OATT). In general, the cost allocation of generation inputs involves 1) a forecast of the necessary amount of generation inputs, energy and/or capacity, 2) an allocation of embedded costs associated with the generation system that is used to provide the generation inputs, 3) an allocation of any other applicable costs, and 4) assignment of these costs to Transmission Services as an input for the transmission rate design.

Cost allocations for generation inputs are developed for the specific services that Transmission Services offers to its customers and for other identifiable generation inputs that Transmission Services needs to maintain system reliability. Generation inputs include Regulating Reserve, Operating Reserve, Wind Balancing Service, Synchronous Condensing, Generation Dropping, Energy and Generation Imbalance, Redispatch, and Station Service. The inter-business line cost allocation also includes the segmentation of Corps of Engineers and Bureau of Reclamation transmission facilities. The latter is not a generation input, but it is a cost in the generation revenue requirement that is assigned to Transmission Services.

Almost all inter-business line cost allocations have been revised for the Final Proposal to reflect the updated revenue requirement and the new market price forecast for the risk analysis. Other changes are addressed in the sections below.

13.2 Inter-business Line Cost Allocation Policy

13.2.1 Introduction

The inter-business line cost allocation policy focuses on allocating costs to Transmission Services ancillary services and control area services on a cost causation basis. Generation inputs are the necessary use of generation resources to provide ancillary services and control area services to support reliable operation of the electrical system, including integration of wind resources. For purposes of forecasting and pricing for the FY 2010-2011 rate period, BPA assumes that all of the generation inputs will come from the FCRPS.

Parties raised inter-business line issues concerning only the Wind Balancing Service rate proposal. However, the methodology used for the Wind Balancing Service cost allocation is also used for Operating Reserve and Regulating Reserve, so decisions made for the Wind Balancing Service rate affect these two cost allocations as well. The focus has been on the Wind Balancing Service rate because BPA is responding in this rate case to the extensive increase in wind generation interconnected to BPA's system and the significant impact the wind generation is having and will have on the operation of the FCRPS. BPA has experienced extensive growth in wind generation in its Balancing Area Authority. In 2007, expectations were that 6,000 MW of wind would be integrated in the Northwest region by the early 2020s. Currently, there is approximately 2,100 MW of wind generation operating in the BPA Balancing Authority Area. The updated installed capacity forecast assumes that by the end of FY 2010, BPA will have integrated 3,198 MW of wind generation. McManus *et al.*, WP-10-E-BPA-42-E01, at 3-14, line 12. BPA forecasts that a total of 3,843 MW of wind generation will be integrated into the BPA Balancing Authority Area by the end of FY 2011. *Id*. at line 24. Although most new wind facilities in the Northwest region are located within the BPA Balancing Authority Area, most of that wind generation is exported out of the Balancing Authority Area to other utilities for their load service. The challenge of wind integration is significantly greater in the BPA Balancing Authority Area than in most other parts of the nation and the world. This is because wind generation constitutes a larger percentage of the total generation in the Balancing Authority Area; the wind generation is highly geographically concentrated, which magnifies the steepness and magnitude of swings in total wind generation; and most of the wind generation is delivered to loads outside the BPA Balancing Authority Area. BPA's hydro-based system is relatively well-suited to integration of wind, but this advantage is more than outweighed by these other factors.

The significant increase in the amount of wind generation in the BPA Balancing Authority Area in a relatively short period of time has challenged BPA, the wind community, and other parties to more fully understand the reserve requirements for reliably integrating the increasing amounts of wind into the power system. The current one-year WI-09 Wind Integration – Within-Hour Balancing Service rate is the first BPA rate that defines and assigns costs to the reserves required to provide this service. The WI-09 rate case resulted in a non-precedential settlement in which BPA and parties acknowledged the need to better understand the service provided to integrate wind generation. The settlement agreement specified tasks and analyses that BPA would undertake with a cross-agency team. Although much of that work has been accomplished and has been reflected in the FY 2010-2011 rates, much remains to be learned about wind integration. Decisions made here may change in future rate proceedings as our experience grows with wind power operating in our Balancing Authority. BPA is fortunate that we have concluded that there are adequate reserves on the existing system to provide integration services for expanding the wind fleet during the FY 2010-2011 rate period. The challenge of procuring and charging for additional reserves will add significant complexity in future rate cases.

One of the primary differences between the FY 2010-2011 Wind Balancing Service rate and the existing WI-09 rate is that the former allocates costs to the capacity needed to provide imbalance reserves for wind generators. The WI-09 rate did not account for imbalance reserves and was based on the regulation and load following reserve components needed to support wind generation. The FY 2010-2011 Wind Balancing Service rate includes all three required reserve components in the reserve forecast and cost allocation.

A key component of determining the forecast amount of required wind balancing reserve is the assumption of scheduling accuracy of wind generators in BPA's Balancing Authority Area. If scheduling accuracy for wind generation is assumed to be relatively poor, BPA must increase the amount of wind balancing reserve, which results in greater costs. Conversely, the better the assumed scheduling accuracy, the lower the resulting reserve requirement, which results in lower costs. The Initial Proposal was based on the historical performance of the wind fleet, which corresponds to a two-hour persistence scheduling accuracy model. Under a two-hour persistence forecast, generation schedules submitted by wind generators are statistically consistent with the output of the generators two hours prior to the scheduling hour. Persistence scheduling descriptions are a method of measuring scheduling accuracy, not a method of scheduling.

The Generation Inputs policy testimony discussed the potential for lowering the scheduling accuracy assumption based on better scheduling behavior by the wind fleet and the implementation of a new Dispatcher Standing Order (DSO) 216. A new DSO 216 should provide a reliability mechanism that would allow BPA's dispatchers to limit the amount of reserves needed through feathering and curtailment orders when the amount of reserves set aside is 90 percent deployed. The issue of the appropriate persistence scheduling accuracy for rate case forecast is addressed in section 13.3.2.3.

13.2.2 Policy Issues

Issue 1

Whether BPA's Wind Balancing Service rate will discourage wind development in the Northwest.

Parties' Positions

Iberdrola Renewables, Inc. (Iberdrola) argues that Staff's proposed Wind Balancing Service rate would impose an inappropriate cost burden on wind generation and would discourage renewable energy development in the Pacific Northwest. Iberdrola Br., TR-10-B-IR-01, at 2. Iberdrola asserts that, from a regional policy standpoint, Staff's proposal would inflate the delivered cost of wind energy in the region above its true cost, making it difficult for the region to meet its clean energy goals and skewing the true cost of renewable energy expansion. *Id*. Accordingly, Iberdrola states, Staff's proposed Wind Balancing Service rate would force Iberdrola to consider self-supplying reserves or establishing its own Balancing Authority Area, either of which would permit it to integrate wind generation at a cost that is lower than Staff's proposed Wind Balancing Service rate. *Id*. at 4.

Northwest Wind Group (NWG) argues that a rate increase of the magnitude proposed by BPA not only risks deterring development of wind energy resources in the Pacific Northwest, but also likely encourages a further balkanization of the regional transmission grid as wind generators establish independent balancing authorities to access lower-cost options for balancing reserves. NWG Br., TR-10-B-NG-01, at 3.

In its Brief on Exceptions, NWG takes issue with BPA's rationale in the Draft ROD that BPA's higher Wind Balancing Service rate will not deter the growth of renewable energy resources in the Northwest. NWG Br. Ex., WP-10-R-NG-01, at 3. NWG claims that BPA's argument is not supported by evidence in the record, past performance is not a guarantee of future results, and renewable energy is not exempt from the laws of economics. *Id*. at 3-5. NWG also notes that it has taken BPA's silence in the Draft ROD as BPA agreement on 1) NWG's articulation of Federal renewable energy policy and 2) NWG's position that increasing the costs of wind integration by 300-400 percent is out of step with current Federal policies that seek to encourage private investment in renewable energy resources. NWG Br. Ex., WP-10-R-NG-01, at 1-2.

PPC *et al.* agree with the conclusion in the Draft ROD, stating that there is strong evidence that BPA's actions, including the development of an appropriate wind integration rate, will facilitate continued widespread development of renewables in the region. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 11.

BPA Staff's Position

Since BPA established the wind integration rate on October 1, 2008, wind generation has continued to grow in the Northwest, and BPA projects continued growth of wind generation during the FY 2010-2011 rate period. Mainzer *et al.*, WP-10-E-BPA-41, at 5. Currently, BPA has integrated approximately 2,100 MW of wind generation in its own Balancing Authority Area, and BPA forecasts a total of 3,843 MW of wind generation integrated into the BPA Balancing Authority Area by the end of FY 2011. McManus *et al.*, WP-10-E-BPA-42-E01, at 3-14, line 24. BPA also is working on extensive wind integration initiatives that are expected to enable the development of even more wind generation in the Northwest. Mainzer *et al.*, WP-10-E-BPA-41, at 5-6.

Evaluation of Positions

Both Iberdrola and NWG contend that Staff's proposed Wind Balancing Service rate will deter renewable energy development. Iberdrola Br., TR-10-B-IR-01, at 2; NWG Br., TR-10-B-NG-01, at 3. Iberdrola further argues that from a regional policy standpoint, Staff's proposal would inflate the delivered cost of wind energy in the region above its true cost, making it more expensive and difficult for the region to meet its clean energy goals and skewing the true cost of renewable energy expansion. Iberdrola Br., TR-10-B-IR-01, at 2.

BPA disagrees with these assertions. The proposed Wind Balancing Service rate is unlikely to deter the growth of renewable energy resources in the Northwest or make it more difficult for the region to meet its clean energy goals. In recent years, the growth of wind generation in the Pacific Northwest has boomed. BPA alone has integrated approximately 2,100 MW of wind and expects to have integrated a total of 3,843 MW of wind into the BPA Balancing Authority Area by the end of the rate period. McManus *et al.*, WP-10-E-BPA-42-E01, at 3-14, line 24. BPA's forecast is based in part on information received directly from wind developers. McManus *et al.*, WP-10-E-BPA-23, at 8. Even with the recent economic downturn, BPA has not seen a noticeable decrease in the amount of wind development in the Northwest:

> As we described in direct testimony, information received directly from project developers in the interconnection process is one of the primary pieces of information considered in developing the estimate [of wind project development over the rate period]. McManus *et al.*, WP-10-E-BPA-23, at 8. The information that developers are conveying to BPA should provide the most direct indication of the impact of economic conditions on their projects and decisionmaking, and that

> information is reflected in our estimates of the projects that will be online during the rate period.

McManus *et al.*, WP-10-E-BPA-42, at 4. Remarkably, BPA now has approximately 14,000 MW of pending wind generator interconnection requests in its Generator Interconnection Queue and continues to receive new wind generator interconnection requests each month. *Id. at 3.* Wind generation on BPA's system will continue to increase even if some generators leave BPA's Balancing Authority Area:

> Most of these requests seek to interconnect by 2013, and generators may submit new requests at any time. Given these dynamics, even if certain projects leave the BAA or delay development, requests for new projects may enter the queue, and projects with existing requests may accelerate their development schedule.

Id. This dramatic growth of wind energy in the BPA Balancing Authority Area is largely attributable to BPA and other Federal, state, and local renewable energy policies that have incentivized renewable energy development, such as renewable energy portfolio standards and production and investment tax credit incentives. Most of the wind generation located in BPA's Balancing Authority Area is exported to satisfy the renewable energy needs of other Balancing Authority Areas. BPA expects load growth in the Pacific Northwest to further strengthen the demand for new renewable sources of generation in the region.

Neither Iberdrola nor NWG offers any evidence in the record to support their broad contentions that the proposed Wind Balancing Service rate will deter development of renewable energy or make it more difficult for the region to meet its clean energy goals. BPA agrees with NWG on the importance of renewable resource development and is working diligently to overcome operational challenges to integrate a large amount of wind generation into the BPA system. *See* Administrator's Preface to the ROD. BPA has worked extensively with the region on many levels, including co-sponsoring the Northwest Wind Integration Action Plan, to break down technical barriers and establish pathways to facilitate large scale wind integration in the Northwest. Although BPA originally proposed a rate significantly higher than the one that would result from the decisions in this ROD, BPA has seen no evidence of a slowing of wind development.

During oral argument, BPA asked counsel for NWG to explain the breakpoint at which wind development in the Northwest would no longer be cost effective. NWG's counsel responded that other renewable resources are likely to be competitive with wind generators as the cost of wind integration increases, but that many variables contribute to the cost-effectiveness of wind development. Hall, Oral Tr. at 40-41. Iberdrola's counsel also explained that a wind developer must weigh many variables before determining whether to locate outside of the Northwest. Skidmore, Oral Tr. at 75-76.

The Initial Proposal Wind Balancing Service rate for installed capacity translates into an approximately $12/MWh charge. Hall, Oral Tr. at 37. BPA asked counsel for NWG which resources would substitute for wind generation if BPA applied a $12/MWh charge to wind integration. NWG's counsel responded that at that price level, "biomass would be competitive," and "[g]eothermal would be competitive." *Id*. at 39 These resources, however, are also renewable resources, which, like wind generation, will be needed to serve load pursuant to state and local renewable energy policies.

During the course of this rate proceeding, the improved scheduling accuracy of the wind fleet has led to a substantial reduction in the Wind Balancing Service rate as compared to the Initial Proposal of approximately $12/MWh. Iberdrola identified its alternative cost at $4.50/MWh. Skidmore, Oral Tr. at 86. This cost seems low to BPA. Other suppliers are charging and receiving rates substantially higher than $4.50/MWh today. As a result of the recent improved scheduling accuracy of the wind fleet, something that BPA hoped would happen in response to the initial rate proposal, BPA is establishing a substantially lower rate in the Final Proposal of approximately $5.70/MWh. This rate is still higher than the alternative cost identified by Iberdrola, but it is below the cost of alternative suppliers. Given that new wind resources are charging in excess of $100/MWh, it seems very unlikely that BPA's Wind Balancing Service rate compared against wind generators' alternatives will impact the market for wind resources.

BPA attributes the recent improvements in the scheduling accuracy of wind generators in large part to the price signal from the proposed Wind Balancing Service rate. Such improved scheduling accuracy leads to a reduced need for balancing reserves, a lower Wind Balancing Service rate, and less risk of BPA running out of reserves and incurring a wind-related reliability event. Avoiding a reliability event is extremely important in terms of promoting renewable resource development both regionally and nationally.

For example, before the development of the rate (and BPA's proposed reliability and operational requirements under DSO 216), BPA was experiencing a level of scheduling accuracy from the wind fleet that was consistent with a two-hour persistence model. McManus *et al.*, WP-10-E-BPA-23, at 17. BPA is now observing scheduling accuracy from the wind fleet in the range of 60-minute persistence scheduling accuracy or better, McManus *et al.*, WP-10-E-BPA-42, at 12-16, with many wind generators arguing that they will improve to 30-minute persistence scheduling accuracy. Iberdrola Br., WP-10-B-IR-01, at 12; NWG Br., WP-10-B-NG-01, at 12. Moving from two-hour to 30-minute persistence would reduce the reserve requirement on the BPA system by nearly 1,000 MW. *See* McManus *et al.*, WP-10-E-BPA-42, at 51, Exhibit 20. The difference between a two-hour and 30-minute persistence scheduling assumption is nearly 400 MW of *inc* reserves and 600 MW of *dec* reserves. *Id*.

Accordingly, lowering the use of balancing reserves reduces BPA's cost-based rate. The proposed Wind Balancing Service rate has fostered improvements in wind fleet scheduling accuracy, and in turn has reduced the need for balancing reserves. Ultimately, rather than deterring the growth of renewable resources, the development of this rate actually promotes widespread renewable resource development and allows more renewable generation to locate in the BPA Balancing Authority Area.

BPA has also taken many actions that should continue to support wind development in the region. In the 1980s, BPA conducted pilot tests of early wind turbine designs and helped to establish wind monitoring centers to gather data that would eventually aid in wind project development throughout the region. Mainzer *et al.*, WP-10-E-BPA-41, at 4. In 1999, BPA interconnected the region's first wind project. Subsequently, BPA exempted wind projects from the third deviation band of BPA's Generation Imbalance Service rate, which eliminated a source of commercial uncertainty and stimulated a rapid increase in wind generation over the following years. *Id*.

In 2007, BPA and the Northwest Power and Conservation Council created a Wind Integration Action Plan to integrate up to 6,000 MW of wind in the Northwest by the early 2020s. *Id*. The authors of the Action Plan expected about 3,000 MW of that wind generation to be located in the BPA Balancing Authority Area over that period of time. *Id*. BPA now forecasts that 3,843 MW of wind generation will be integrated into the BPA Balancing Authority Area by the end of FY 2011. McManus *et al.*, WP-10-E-BPA-42-E01, at 3-14, line 24. BPA and the region have made and continue to make substantial progress on all 16 of the Action Plan's recommendations. Mainzer *et al.*, WP-10-E-BPA-41, at 4.

BPA's experience with wind integration expanded even further in 2007, when BPA developed its Network Open Season concept. The 2008 Network Open Season was an innovative queue management and planning process that resulted in 3,700 MW of new transmission service offers to wind energy projects. BPA already has undertaken financing and construction on the John Day-McNary transmission line, a critical piece of BPA's transmission system linking the windy Columbia River Gorge to load centers across the West. Mainzer *et al.*, WP-10-E-BPA-41, at 4-5. BPA has begun environmental review on three other lines that will reinforce the transmission system to accommodate wind energy. BPA began its second Network Open Season in June 2009.

In addition to Network Open Season, BPA began offering Conditional Firm transmission service for up to 1,200 MW of new service requests, with the majority of these requests being for wind generators in the Northwest. BPA is now the largest provider of Long-Term Conditional Firm Transmission Service in the nation and is the only transmission provider in the nation to offer a Conditional Firm Network Integration Transmission Service Product. *Id*. at 5.

Currently, there is approximately 2,100 MW of wind generation operating in the BPA Balancing Authority Area. *See* Generation Inputs Study and Documentation, WP-10-E-BPA-08, at 27. The updated installed capacity forecast assumes that by the end of FY 2010, BPA will have integrated 3,198 MW of wind generation. McManus *et al.*, WP-10-E-BPA-42-E01, at 3-14, line 12. BPA forecasts that 3,843 MW of wind generation will be integrated into the BPA Balancing Authority Area by the end of FY 2011. *Id*. at line 24.

BPA's Wind Integration Team is developing a set of operating protocols that will allow BPA to continue integrating new wind plants while reliably maintaining the BPA system during extreme wind events. These operating protocols will be formalized in DSO 216. Mainzer *et al.*, WP-10-E-BPA-22, at 20-21. BPA now expects DSO 216 to facilitate the interconnection of an additional 1,700 MW of new wind generation into BPA's system by the end of the FY 2010-2011 rate period.

Furthermore, BPA recently reinforced its Wind Integration Team by hiring five additional staff members to explore self-supply options and implementation of sub-hourly transmission scheduling, both of which will aid wind generation development in the region. Mainzer *et al.*, WP-10-E-BPA-41, at 5-6.

Accordingly, based on the rapid and successful growth of wind development in the Northwest to date, BPA's aggressive wind integration initiatives, and recent Federal and state incentives for wind development, BPA disagrees that the Wind Balancing Service rate will discourage the continued growth of wind and renewable resources. On the contrary, the rate is competitive with alternative costs of supplying wind balancing service. In addition, the rate provides incentives to improve scheduling practices that have and will continue to substantially reduce the amount of reserves required and reduce the cost-based rate. And the improved scheduling and resultant reduction in the amount of required reserves helps to avoid a wind-related reliability event. Thus, BPA believes that this rate promotes widespread renewable resource development, particularly within the BPA Balancing Authority Area.

NWG asserts that since BPA did not respond in the Draft ROD, BPA must agree that the 300-400 percent increase in the Initial Proposal Wind Balancing Service rate is out of step with current Federal policies that seek to encourage private investment in renewable energy resources. NWG Br. Ex., WP-10-R-NG-01, at 1-2. BPA did not respond in the Draft ROD to NWG's contention because BPA's Final Wind Balancing Service rate proposal does not represent a 300 to 400 percent increase. BPA believes that NWG's statement misses some important context, as noted in the Administrator's Preface. BPA agrees that renewable energy development is an important goal at the regional and Federal levels, and BPA has been working diligently on meeting that goal. A critical limiting factor to that goal is whether adequate reserves can be provided to maintain reliability as large amounts of wind resources are added within the BPA Balancing Authority. To further the goal, it is important to identify and fully understand the operational requirements placed on the system by wind generation and to accurately price that service. It is also important to send appropriate price signals as to the cost of providing the Wind Balancing Service. In order to do this, BPA relies on cost causation principles to guide its ratemaking methodology. The proposed rate reflects the cost of the imbalance component of the reserve required for Wind Balancing Service that had not been included in the current rate. Ignoring this additional reserve amount, even though it resulted in a rate increase, would not result in a cost-based rate and thus would not send appropriate price signals to the market. This would likely lead to an inefficient use of reserves on the BPA system. Due to the various efforts outside the rate case *(i.e.*, WIT initiatives) and in the rate case, the amount of required reserves and the cost of that service will decrease for the Final Proposal but still will be higher than the current rate. Sending appropriate price signals is consistent with Federal policies and will allow more renewable resource development to be interconnected to the BPA system.

NWG's Brief on Exceptions challenges BPA's assertion that increasing the Wind Balancing Service rate will not deter the growth of renewable energy resources in the Northwest and claims that BPA's arguments are not supported by evidence in the record. NWG Br. Ex., WP-10-R-NG-01, at 3. NWG lists BPA's arguments that NWG claims are mistaken and not supported by evidence in the record: 1) renewable energy growth in recent years has been strong, 2) NWG and Iberdrola have not put evidence into the record that higher wind balancing service rates will deter the growth of renewable energy resources in the Northwest or make it more difficult for the region to meet its clean energy goals, 3) BPA's proposed higher rate has, during the period of the rate case, actually improved scheduling accuracy and had the effect of lowering the rate, 4) BPA's rate is low compared to rates of other suppliers, and wind energy has enough margin in its selling price to be able to absorb a large increase in the Wind Balancing Service rate, and 5) wind energy will continue to develop regardless of the rate level because of BPA's prior wind-related actions. *Id*.

First, the record supports BPA's assertion that renewable energy growth in recent years has been strong, and the record supports BPA's forecast that this growth will continue. Mainzer *et al.*, WP-10-E-BPA-22, at 13-14; McManus *et al.*, WP-10-E-BPA-42, at 2; Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, Section 2. NWG claims that this past performance is no guarantee of continued renewable energy growth, because in the past the wind generators did not have to contend with a high wind integration rate, and BPA's inquiry has been limited to only a review of its interconnection queue. NWG Br. Ex., WP-10-R-NG-01, at 4. NWG's assertions are misplaced. BPA updated its forecast of installed wind generation capacity during the rate case based on the most recent indication from wind developers as to the status of pending projects. At that time wind generation developers were keenly aware of the potential of a significant increase in the Wind Balancing Service rate. BPA's forecast was not simply based on a review of its queue. Rather, the forecast relies heavily on information received directly from project developers in the interconnection process. McManus *et al.*, WP-10-E-BPA-42, at 4; McManus *et al.*, WP-10-E-BPA-23, at 8.

Second, other than rhetorical statements in testimony and briefs, Froese *et al.*, WP-10-E-IR-01, at 35; Shimshack and Gramlich, WP-10-E-NG-02, at 6-7; Iberdrola Br., WP-10-IR-01, at 2-4; NWG Br., WP-10-B-NG-01, at 3 and 11, NWG and Iberdrola have not put evidence into the record that higher wind integration rates will deter the growth of renewable energy resources in the Northwest or make it more difficult for the region to meet its clean energy goals. This issue was discussed at oral argument, and it is clear that no economic analysis has been put on the record by NWG or Iberdrola to back up these assertions. Hall, Oral Tr. at 37-41; Skidmore, Oral Tr. at 74-76.

Third, the record supports BPA's argument that BPA's higher rate proposal has been a factor in improving the actual scheduling accuracy during the course of the rate case. Since BPA began rate case workshops, and wind generators became aware of the impact that scheduling accuracy could have on the level of the Wind Balancing Service rate, the wind fleet's scheduling accuracy improved from 2 hours to 60 minutes. McManus *et al.*, WP-10-E-BPA-42, at 13-15. This issue is addressed in more detail in section 13.3.2.3, Issue 5.

Fourth, to support its claim that BPA is relying on evidence outside the record to support the argument that BPA's rate is low compared to rates of other suppliers, and wind energy "somehow" has enough margin in its selling price to be able to absorb a large increase in the Wind Balancing Service rate, NWG cites to the Draft ROD statements that 1) new wind resources are charging in excess of $100/MWh for wind and 2) unidentified "other suppliers" are providing wind balancing services at rates "substantially higher than $4.50/MWh." NWG Br. Ex., WP-10-R-NG-01, at 5. The statement that new wind generators are charging $100/MWh was brought into the record at oral argument in the discussion between the

Administrator and counsel for NWG. Hall, Oral Tr. at 37-38. The statement regarding other suppliers charging substantially more is supported by recent Commission opinions, such as *Northwestern Corporation,* 121 FERC ¶ 61,204 (2007). Moreover, BPA's Wind Balancing Service rate at the conclusion of this case is less than $6.00/MWh. Whether this is compared against Iberdrola's $4.50/MWh proposed rate or something higher, it seems unlikely to make a significant difference in decisions regarding the development of renewable resources.

Fifth, the record supports BPA's assertion that wind generation will continue to develop in the Pacific Northwest. Mainzer *et al.*, WP-10-E-BPA-41, at 4-6. NWG claims that BPA's prior efforts to integrate wind generation are no guarantee that the high wind integration rate will not drive wind generation away. NWG Br. Ex., WP-10-R-NG-01, at 4. As discussed above, BPA has a long history of being committed to the development of wind generation; that commitment will continue into the future; and there has been no indication from wind developers currently in the interconnection process that BPA's Wind Balancing Service rate will drive them out of the Northwest.

Finally, NWG claims that its contention that the higher rate will discourage renewable development in the Pacific Northwest rests on the fundamental principle of supply and demand, under which the demand for any product will tend to fall when the price increases. *Id.* at 4. NWG asserts that by arguing that a higher Wind Balancing Service rate will not discourage the development of renewable energy in the Northwest, BPA is arguing that in the case of renewable energy the laws of economics have been suspended in the Pacific Northwest. *Id.* at 4-5. When Renewable Portfolio Standards have been adopted in the three west coast states, the law of economics (supply and demand) has been fundamentally affected by governmental action (statutory demands). As discussed above, NWG counsel recognized at oral argument that this is a question between renewable resource options, not a question of whether there will be renewable resources developed in the Pacific Northwest. Hall, Oral Tr. at 39.

PPC *et al.* stated that there is strong evidence that BPA's actions, including the development of an appropriate wind integration rate, will facilitate continued widespread development of renewables in the region. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 11.

Decision

BPA's Wind Balancing Service rate will promote widespread renewable resource development in the Northwest. In any case, renewable resource developers should pay costs lawfully allocated to them.

Issue 2

Whether BPA's Wind Balancing Service rate proposal constitutes an improper cost shift to preference customers or wind generators.

Parties' Positions

Iberdrola urges BPA to adopt a rate structure that will enable the integration of wind generation on the BPA system in a fair and not unduly discriminatory manner, and without subjecting preference customers or wind generators to improper cost shifts. Iberdrola Br., WP-10-B-IR-01, at 24. Iberdrola claims that Staff's proposal does not result in wind generators bearing a fair share of the costs, improperly subsidizes power rates, shifts virtually all of the risk from BPA to wind generators, and seeks to assure BPA that all possible outcomes associated with variability of wind are covered by wind generators. *Id*.

PPC *et al.* state that with the large amount of wind generation interconnecting into the BPA Balancing Area in the last year, and the even larger amount of wind expected to interconnect during the next rate period, Staff has proposed appropriate steps in this rate case to identify and recover the costs of balancing wind generation. PPC *et al.* Br., WP-10-B-JP11-01, at 28-29. PPC *et al.* state that Staff has proposed appropriate steps in this rate case to identify and recover the costs of balancing wind generation and that Staff has correctly applied cost causation principles to the development of the cost components and design of the rate. *Id*.

M-S-R Public Power Agency (MSR) recognizes that setting the wind balancing rate requires a delicate balance between load and wind, and that it is important to use transparent and verifiable cost causation principles. MSR Br., WP-10-B-MS-01, at 6-7. MSR suggests that the proposed increase in the wind balancing rate contained in the Initial Proposal is simply a revenue stream needed to reduce the preference rates, and because other factors have reduced the pressure on the preference rate, there is now no reason to increase the wind balancing rate above the WI-09 rate level. *Id*.

NWG's Brief on Exceptions states that BPA has made significant advances toward developing a cost-based rate, but the rate continues to be a subsidy to BPA's preference customers. NWG Br. Ex., WP-10-R-NG-01, at 2.

Cowlitz's Brief on Exceptions states that BPA's Draft ROD struck the right balance and represents a reasonable resolution of the suite of issues surrounding the measure of generation inputs to the Wind Balancing Service rate. Cowlitz Br. Ex., WP-10-R-CO-01, at 2.

BPA Staff's Position

The Initial Proposal, modified to account for better scheduling accuracy, the updated forecast of installed wind capacity, and the new reserve forecasting method and inputs, is a fair and not unduly discriminatory rate. Mainzer *et al.*, WP-10-E-BPA-41, at 26, 28; *see also* McManus *et al.*, WP-10-E-BPA-42, at 2-5, 22-27. The modified Initial Proposal is based on cost causation principles and strikes the right balance between the preference customers' interest in avoiding cost shifts and the wind generators' interest in not subsidizing power rates. Mainzer *et al.*, WP-10-E-BPA-41, at 26, 28.

Evaluation of Positions

Iberdrola explains that it is not seeking to avoid paying its fair share of costs associated with the integration of wind generation, but Staff's Initial Proposal does not represent a fair share of these costs for wind generators and instead serves to improperly subsidize power rates. Froese *et al.*, WP-10-E-IR-01, at 36. Conversely, PPC *et al.* take the position that BPA must adopt a rate and rate design that ensure recovery of the full costs of providing the Wind Balancing Service and that avoid the unintended consequences of under-recovered costs and increased costs for other customers. PPC *et al.*, WP-10-E-JP6-01, at 8. PPC *et al.* state that the rigorous application of the cost causation principle of ratemaking is key to fair and non-discriminatory power and transmission rates. *Id*.

BPA's fundamental pricing principle is to apply cost causation to all firm uses of the system. Mainzer *et al.*, WP-10-E-BPA-41, at 3. Staff applied the ratemaking principle of cost causation to the proposed Wind Balancing Service rate. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 5-101; Mainzer *et al.*, WP-10-E-BPA-22; McManus *et al.*, WP-10-E-BPA-23; Klippstein *et al.*, WP-10-E-BPA-24; Bermejo and Beale, WP-10-E-BPA-25; Mainzer *et al.*, WP-10-E-BPA-41; McManus *et al.*, WP-10-E-BPA-42; Klippstein *et al.*, WP-10-E-BPA-43; Bermejo and Beale, WP-10-E-BPA-44.

Iberdrola, NWG, and MSR raise several issues and arguments against specific aspects of the Wind Balancing Service rate proposal. These issues are addressed in this chapter and also Chapter 20 of this ROD. With the modification described by Staff, McManus *et al.*, WP-10-E-BPA-42, at 2-5, 22-27, and the changes discussed in response to these other issues, BPA's final Wind Balancing Service rate is based on cost causation principles, and it will not result in an improper cost shift to either wind generators or BPA's power customers.

MSR's suggestion that the proposed increase in the Wind Balancing Service rate contained in the Initial Proposal is simply a revenue stream needed to reduce the preference rates, MSR Br., WP-10-B-MS-01, at 6, is a mischaracterization of the BPA ratesetting process. There is no basis in fact or the record for MSR's accusation that the wind rate was developed as a revenue stream to relieve the upward pressure on the preference rate. BPA began the process of establishing a Wind Balancing Service rate in the WI-09 rate proceeding. Mainzer *et al.*, WP-10-E-BPA-22, at 15-16. This process was initiated by the significant increase in the amount of wind interconnected to the BPA system. Staff explained:

> BPA and the parties to the WI-09 rate proceeding entered into a settlement of the case. BPA agreed to, among other things, conduct a series of public rate case workshops as part of the WP-10 rate case to develop a methodology for estimating within-hour regulation and following reserve needs to accommodate expected higher levels of wind integration and changing system operations within the BPA BAA. BPA agreed to propose the methodology resulting from such workshops as the basis for estimating the quantity of within-hour reserve needs in the Initial Proposal.

Id. at 16.

BPA's Wind Balancing Service rate is based on methodologies and forecasts that have been developed as part of an ongoing public process. MSR's representatives have participated in this ongoing public process, and there is no basis for MSR to suggest now that BPA is somehow using the Wind Balancing Service rate as a tool to reduce its preference customers' rates.

NWG's Brief on Exceptions contends that the litmus test for a cost-based Wind Balancing Service rate should be whether the PF power rate paid by BPA's preference customers is affected by the level of reserves provided to wind customers. NWG Br. Ex., WP-10-R-NG-01, at 2. If providing a greater amount of reserves to wind generators causes the PF rate to increase, the Wind Balancing Service rate would be too low. *Id*. Likewise, if providing a greater amount of reserves to wind generators causes the PF rate to decline, BPA is, in effect, making a profit on wind integration and thus setting the Wind Balancing Service rate too high. *Id*. NWG argues that the BPA Wind Balancing Service rate fails this test, because as presented in BPA's June 29, 2009, rates workshop, the projected PF rate is lower at a 45-minute scheduling accuracy assumption than a 30-minute scheduling accuracy assumption. *Id*.

NWG's litmus test fails to recognize that, consistent with cost causation principles, the Wind Balancing Service rate includes embedded costs of the system. Under the embedded cost methodology, providing fewer reserves under the 30-minute scheduling accuracy assumption as compared to the 45-minute scheduling accuracy assumption should cause the PF rate to increase, because fewer costs are allocated to the Wind Balancing Service rate when fewer reserves are forecast. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, Table 3.8, at 66. Under the embedded cost methodology, costs not allocated to the Wind Balancing Service rate must be recovered through BPA's power rates, and thus the PF rate is affected by changing from a 45-minute to a 30-minute scheduling accuracy assumption.

NWG claims that BPA's failure of NWG's misinformed litmus test shows that the Wind Balancing Service rate continues to provide a subsidy to BPA's preference customers. NWG Br. Ex., WP-10-R-NG-01, at 2. This suggests that the amount of reserves BPA is required to provide from the hydro system should have no effect on BPA's power rates. Allocating embedded system costs to other uses of the system will always have an effect on the rates of power customers responsible for paying the remaining system cost. This is not a subsidy; rather, it is an effect of normal cost causation ratemaking. NWG's litmus test and subsidy argument is essentially the same as arguing that wind generators should pay only the incremental costs they impose on the system. BPA does not agree with that position. That issue is addressed below in Issue 5 and in section 13.4.2, Issue 6.

Cowlitz's Brief on Exceptions states that BPA's Draft ROD struck the right balance and represents a reasonable resolution of the suite of issues surrounding the measure of generation inputs to the Wind Balancing Service rate. Cowlitz Br. Ex., WP-10-R-CO-01, at 2.

Decision

BPA's Wind Balancing Service rate is based on cost causation and does not constitute an improper cost shift to power customers or wind generators.

Issue 3

Whether the significant increase in variable generation interconnecting to BPA's transmission system is imposing costs and operating constraints associated with within-hour balancing services that necessitate setting a rate to recover these costs.

Parties' Positions

MSR questions whether there is a cost associated with wind integration and balancing within-hour variations of wind generation. MSR Br., WP-10-B-MS-01, at 6. According to MSR, Staff has proposed a "within hour" wind integration charge to recover a "cost" that arguably does not exist as a way to provide a revenue stream to supplement net secondary revenues. *Id*. MSR also maintains that the increase in BPA's borrowing authority since the Initial Proposal has eliminated the need to set a rate for "within hour" wind integration before the requisite work has been done to clarify and confirm the costs and the benefits of wind integration. *Id*. at 7.

No other party questions whether the costs of wind integration actually exist.

PPC *et al.* state in their Brief on Exceptions that BPA demonstrates conclusively in this proceeding and elsewhere that wind generators are imposing significant costs and operating constraints on the BPA system that necessitate a rate to recover those costs. PPC *et al.* Br. Ex. WP-10-R-JP12-01, at 11-12.

BPA Staff's Position

Increasing levels of variable generation require increasing amounts of balancing reserves for the BPA Balancing Authority to continue to meet reliability criteria. Mainzer *et al.*, WP-10-E-BPA-22, at 13; McManus *et al.*, WP-10-E-BPA-42, at 2; Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, Section 2. The reserves result in operational impacts and costs on the BPA power system. Mainzer *et al.*, WP-10-E-BPA-22, at 12-15.

Evaluation of Positions

The record includes substantial compelling evidence demonstrating that the amount of wind being integrated into BPA's system is growing rapidly and that BPA is incurring verifiable costs to integrate that generation and provide within-hour balancing services. Wind generation in BPA's Balancing Authority Area has roughly doubled each year from 2004-2008, and there will be close to 4,000 MW by the end of the FY 2010-2011 rate period. Mainzer *et al.*, WP-10-E-BPA-22, at 13; McManus *et al.*, WP-10-E-BPA-42-E01, at 3-14, line 24. PPC *et al.* note that the operational issues associated with this rapid increase place BPA at the "frontier of wind integration in the United States" and that the ratio of installed wind capacity to peak load in the BPA Balancing Authority Area could climb as high as 30 percent during the rate period. Baker *et al.*, WP-10-E-JP6-1, at 5-6. According to PPC *et al.*, BPA's wind penetration level will be among if not the highest in the country if this occurs. *Id*. at 6. PPC *et al.* observe that BPA demonstrates conclusively in this proceeding and elsewhere that wind generators are imposing significant costs and operating constraints on the BPA system. PPC *et al.* Br. Ex. WP-10-R-JP12-01, at 11-12. BPA's Preliminary Needs Assessment of the capacity available to provide balancing reserves associated with wind generation raises questions about the ability of the system to provide adequate reserves in the future. *See* Dragoon, WP-10-E-NG-01-AT02.

MSR suggests that, despite this evidence of the rapid growth in wind generators connecting to BPA's system during the rate period, BPA should not set a new rate for Wind Balancing Service in this proceeding, because there are no costs associated with wind integration and within-hour balancing services, or the costs are insufficiently verified. MSR Br., WP-10-B-MS-01, at 6-7.

This is a curious argument, because MSR's own testimony seems to acknowledge that BPA's cost to integrate wind generation has increased as more wind generators connect to the system. Arthur, WP-10-E-MS-04, at 10. ("3 years ago BPA withdrew the offer to firm and shape the wind. This suggests that the cost was increasing as the quantity of wind increased. Two years ago BPA introduced the concept of the [Wind Balancing Services rate]. This further suggests that the cost of integration is increasing as the quantity of wind increases.").

In addition, MSR emphasizes that "it is important to use transparent and verifiable cost causation principles in setting the 'within hour' wind integration charge" to avoid cross-subsidization between load and wind. MSR Br., WP-10-B-MS-01, at 6. The current WI-09 rate was the product of a non-precedential settlement, however, rather than full review of the costs in a contested proceeding. Moreover, the WI-09 rate does not include a component for imbalance capacity, so maintaining the current rate would not reflect any cost of capacity associated with inaccurate scheduling. Mainzer *et al.*, WP-10-E-BPA-41, at 20. Based on the evidence in the record, MSR's suggestion to maintain the current (WI-09) rate through FY 2011 appears inconsistent with cost causation principles.

Although the record reflects the significant disagreement over the pricing methodology and the cost allocation to the Wind Balancing Services rate, MSR appears to be unique in questioning whether such costs exist. Staff has described at length the costs of and limitations on flexibility of the system associated with holding capacity for balancing reserves. Bermejo and Beale, WP-10-E-BPA-25, at 2, 9, 12, 15-17, 19-23; Mainzer *et al.*, WP-10-E-BPA-22, at 12-15; Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, Section 4. PPC *et al.* correctly state that Staff has supported the calculation of these costs with substantial evidence and clearly explained how each component recovers discrete system costs. PPC *et al.* Br., WP-10-B-JP11-01, at 30.

Decision

The increase in variable generation interconnecting to BPA's transmission system is imposing costs and operating constraints associated with within-hour balancing services that necessitate setting a Wind Balancing Service rate in this proceeding to recover these costs. The existence of these costs is supported by substantial evidence in the record.

Issue 4

Whether BPA is proposing a 400 percent rate increase for Wind Balancing Service, and whether the proposed rate increase is justified.

Parties' Positions

Iberdrola states that Staff proposes to increase the Wind Balancing Service rate up to 350 percent, and contends that the increase rests upon flawed and controversial methodologies and assumptions. Iberdrola Br., WP-10-B-IR-01, at 1-2.

NWG states that Staff's proposed Wind Balancing Service rate increase of approximately 400 percent is a direct result of certain recent BPA policy decisions and argues that the Wind Balancing Service rate should be declining. NWG Br., WP-10-B-NG-01, at 1.

MSR characterizes the proposed Wind Balancing Service rate as "punitive" and argues that BPA should withdraw the proposed Wind Balancing Service rate that reflects a 400 percent increase, or set it at a level in line with the current WI-09 rate. MSR Br., WP-10-B-MS-01, at 2, 3, 20.

BPA Staff's Position

The pricing methodologies used for the Wind Balancing Service rate proposal are based on the principle of cost causation. Mainzer *et al.*, WP-10-E-BPA-41, at 3, 19-20. The majority of the Initial Proposal rate increase is due to including the costs of carrying within-hour balancing reserves to account for the inaccuracy of the schedules submitted by wind generators, which was not considered in the generation reserve forecast methodology used to establish the WI-09 rate. *Id*. at 20. The increased need for capacity for the imbalance component of the reserve requirement is caused by the increase in installed wind capacity in the BPA Balancing Authority Area, and more accurate allocation of the total reserve requirement according to the relative contribution from load and wind. Mainzer *et al.*, WP-10-E-BPA-22, at 16-17. The increased costs attributed to wind within-hour balancing service reflect the rapid growth of wind development in the BPA Balancing Authority Area. With the resulting increased variation of actual generation to scheduled generation, more of the Federal system resource capability is being utilized to provide generation inputs. Mainzer *et al.*, WP-10-E-BPA-41, at 20.

Evaluation of Positions

Although parties have referred to a 400 percent increase, the initial proposal Wind Balancing Service rate increase is actually 300 percent. The WI-09 rate is $0.68 per kilowatt of installed capacity per month, and the Initial Proposal Wind Balancing Service rate was $2.72 per kilowatt of installed capacity per month. Although this does not change the fact that the proposed increase is significant, fundamental underlying factors must be considered in evaluating the increase.

The comparison to the current WI-09 rate is not an "apples-to-apples" comparison. Since the time that the WI-09 rate was settled, and in part because of the focus that the settlement put on further exploration and analysis of the effect of wind generation on Balancing Authority Area reliability, BPA's Wind Integration Team (WIT) has clarified the need for capacity reserve for imbalance service. McManus *et al.*, WP-10-E-BPA-23, at 23-27. This rate proceeding is the first time BPA can incorporate the imbalance component of the reserve requirement into its rate methodology, and the imbalance reserve requirement is the largest component of the proposed Wind Balancing Service rate. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 35. Given that the need for the additional reserve requirement was not fully understood at the time the WI-09 rate was settled, it is inappropriate to compare the settled WI-09 rate level to the proposed Wind Balancing Service rate without some recognition that the underlying assumptions of the reserve requirement have fundamentally changed since the WI-09 rate settlement. In addition, the Initial Proposal forecast of wind generation interconnected to

BPA's system during the rate period is more than double the wind generation interconnected during FY 2009. *Id*. at 26-30, Table 2.1.

The parties to the WI-09 rate settlement agreed that no precedent was being established. The WI-09 Settlement Agreement states:

> The signatories agree that they will not assert in any forum that anything in this settlement agreement or any action with regard to this settlement agreement taken or not taken by any signatory, the Hearing Officer, the Administrator, FERC, or a court, creates or implies any procedural or substantive precedent or creates or implies agreement to any underlying principle or methodology, or creates any precedent under any contract between BPA and any signatory.

WI-09 Record of Decision, WI-09-A-01, at Appendix A, page 5. The rate schedule, including the level of the rate, was in the settlement agreement. NWG agreed during oral argument that the WI-09 rate was not precedential, that "the 2010 rate needs to stand on its own merits" and that NWG was "not relying upon the settled rate" in its arguments. Hall, Oral. Tr., at 23.

The proposed rate is based on cost causation principles that require the embedded costs of the system to be allocated to the firm uses of the system. Mainzer *et al.*, WP-10-E-BPA-41, at 3. In addition, identified variable costs associated with changes in the fuel supply of the FCRPS should be allocated to the provision of generation inputs. *Id*. at 4.

Iberdrola, NWG, MSR, and Cowlitz argue about various aspects of Staff's rate proposal and propose changes. These arguments are discussed in detail in sections 13.3 and 13.4 below. With respect to the magnitude of the proposed rate increase, NWG proposes that BPA could abandon its cost causation standard and simply set a rate that is 10 percent higher than the current WI-09 rate. NWG Br., WP-10-B-NG-01, at 42. MSR proposes that BPA set a rate more in line with the WI-09 rate. MSR Br., WP-10-B-MS-01, at 20. NWG bases its recommendation on recognition of improvements in scheduling accuracy, BPA's ability to manage reserves amounts through DSO 216, and BPA's commitment to operational advances that are likely to occur in the near term. NWG Br., WP-10-B-NG-01, at 42. MSR argues that the proposed rate is "punitive and poorly conceived" and therefore should be abandoned. MSR Br., WP-10-B-MS-01, at 19-20.

There has been no compelling reason put forth to abandon the cost causation principle for Wind Balancing Service rate development. BPA must attempt to set rates that accurately reflect the cost of providing the service so that the marketplace can react accordingly. To the extent the cost of providing Wind Balancing Service decreases over the rate period due to the efforts of BPA, wind generators, and other Balancing Authority Areas, that cost reduction will be reflected in the next rate case.

Finally, while the increase reflected in the Initial Proposal Wind Balancing Service rate is substantial, it was an initial and not a final proposal. Recognizing the ongoing nature of the work of the WIT and efforts of the wind community, Staff states that it has updated certain aspects of its proposal as the case progressed. Mainzer *et al.*, WP-10-E-BPA-22, at 20-22; McManus, *et al.*, WP-10-E-BPA-23, at 11, 24. In addition, Staff provides information regarding the possibility of using different scheduling accuracy assumptions to set the final rate, and what the rate effect might be. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 58, 66. Since the Initial Proposal, Staff has updated its estimate of the installed wind capacity for the rate period, which is almost 700 MW less than the estimate in the Initial Proposal. In addition, Staff analyzed more recent wind scheduling behavior, and that analysis showed actual performance correlating to a 60-minute scheduling assumption. Staff introduces this information in rebuttal testimony. McManus *et al.*, WP-10-E-BPA-42, at 2, 13-14. The scheduling accuracy assumption to use for the Final Proposal is discussed in detail in section 13.3.2.3. The Initial Proposal is a starting point for the rate case; evidence on the entire record is considered and weighed in determining the final rate level.

Decision

The Wind Balancing Service rate increase will be based on decisions on each relevant issue. The increase over the WI-09 rate is an inappropriate comparison due to the settled nature of the WI-09 rate and the inclusion of the imbalance reserves component in this case for the first time. The rate will be based on the principle of cost causation.

Issue 5

Whether Wind Balancing Service should be priced at a level that reflects only the incremental cost of providing this service and should not be allocated a portion of the embedded cost of the system.

Parties' Positions

MSR argues that calculating the incremental impact on the flexibility of the system is a reasonable way to allocate costs without having load or wind subsidize the other. MSR Br., WP-10-B-MS-01, at 16.

NWG states that the variable costs represent Staff's estimate of all of BPA's operational costs incurred in providing wind balancing service. NWG Br., WP-10-B-NG-01, at 21. NWG claims that allocating this incremental amount alone to the Wind Balancing Service rate should be more than adequate to hold BPA's native load customers harmless for the provision of Wind Balancing Service from the Federal system. *Id*.

PPC *et al.* state that it is particularly important that BPA capture all of its legitimate and verifiable costs of providing Wind Balancing Service and recover those costs through the Wind Balancing Service rate. PPC *et al.* Br., WP-10-B-JP11-01, at 29. PPC *et al.* disagree with NWG. PPC *et al.* state that if the embedded costs of the Big 10 hydro units are borne solely by requirements customers, the Wind Balancing Service rate would not meet the standard of cost causation. *Id*. at 31.

MSR claims in its Brief on Exceptions that allocating embedded system costs, which the publicly owned customers have traditionally paid, to wind generators is only an effort to have wind generators take on a burden specifically allocated to power customers in the BPA statutes. MSR Br. Ex., WP-10-R-MS-01, at 3.

BPA Staff's Position

Basing the Wind Balancing Service rate on the incremental costs would violate the principle of cost causation. Mainzer *et al.*, WP-10-E-BPA-41, at 7.

Evaluation of Positions

MSR argues that BPA should not socialize the cost of integrating wind by charging all wind generators the same rate for the reserves needed to support wind. Instead, MSR suggests, existing wind generators should not have to pay the same Wind Balancing Service rate as new wind generators, because it is the additional need for capacity reserves caused by the new wind generators that is affecting BPA's system. Arthur, WP-10-E-MS-04, at 10-11. This approach to rate design suggests that each new wind project should pay an incrementally higher cost as more capacity reserves are needed to support the integration of the entire wind fleet. *See* McManus *et al.*, WP-10-E-BPA-42, at 22. BPA does not believe this is an appropriate way to set rates for a firm service, and this would send the wrong price signal to new wind developers given that the Wind Balancing Service is being wholly provided by the current Federal system resources for the FY 2010-2011 rate period. To the extent that BPA needs to acquire new sources of reserves in the future, BPA and parties will explore alternatives, including incremental cost pricing, to the current pricing method. Finally, an approach of determining the incremental cost that each new wind generator places on the system could be administratively burdensome.

NWG claims that BPA's variable costs represent the incremental costs that BPA incurs to provide Wind Balancing Service, and allocating only these costs should hold BPA's power customers harmless. Dragoon, WP-10-E-NG-01, at 26. The issue of whether the variable costs alone would hold BPA's power customers harmless is addressed in section 13.4.2 Issue 6. NWG appears to argue that wind generators should pay only the incremental costs they impose on the system. This is not a reasonable approach to ratemaking, because Wind Balancing Service is a significant firm use of the FCRPS, and BPA believes that the users of this service should pay a share of the embedded costs of the system that is utilized to provide this service. Staff explains:

> Provision of within-hour balancing reserves is a required use of the system. We propose to allocate a share of the revenue requirement of the FCRPS to the use of the system that provides *inc* capability for within-hour balancing reserves proportionate to the other required and firm uses of the system. Failure to allocate a share of the revenue requirement of the FCRPS to the use of the system to provide *inc* capability for within-hour balancing reserves would result in other users of the system paying the costs for this use. Allocating embedded costs to these uses is consistent with the ratemaking principle of cost causation.

Mainzer *et al.*, WP-10-E-BPA-22, at 12.

NWG claims that allocating embedded cost to the Wind Balancing Service rate results in an unreasonable subsidy to BPA's preference customers. Dragoon, WP-10-E-NG-01, at 27-28. PPC *et al.* respond to NWG assertion, stating:

> Allocation of a share of these costs to the WI-10 rate is appropriate because these are the plants that are producing capacity reserves that are used to provide the

> Wind [Balancing] Service, and wind plants should pay their share of the embedded costs of the physical system used to provide service to them. The witness's assertion that this constitutes a "subsidy" of power customers is based on the implicit assertion that new uses of the physical system should only be required to pay the incremental costs of use of the system. This is contrary to the basis on which costs are allocated to the users of the system who cause them to be incurred and is poor rate policy because it discourages investment in the power system.

Baker *et al.*, WP-10-E-JP6-03, at 22.

MSR claims in its Brief on Exceptions that allocating embedded system costs to wind generators is an effort to have wind generators take on a burden specifically allocated to power customers in the BPA statutes. MSR Br. Ex., WP-10-R-MS-01, at 3. Interestingly, MSR does not provide a statutory citation for this misstatement of the law or justify its free rider approach based on traditional ratemaking principles. Nothing in BPA's enabling statutes has ever been interpreted to prevent BPA from allocating system costs to Transmission Services for generation inputs to services that require generation capacity or energy. Allocating embedded generation system costs to ancillary services and control area services is a commonly accepted ratemaking practice. Allocating embedded cost to wind generators is not an effort to have wind generators take on a burden specifically allocated to power customers. Rather, it is an effort to ensure that wind generators are paying for a share of the embedded cost of the system comparable to the portion of the system that is committed to providing the Wind Balancing Service.

It is worth noting that cost allocations under the embedded cost pricing methodology do not allocate a share of all of BPA's embedded costs to the Wind Balancing Service rate. Only the Big 10 resources are included, because these are the hydro projects that are on Automatic Generation Control (AGC); thus, these are the projects BPA uses to provide Wind Balancing Service. Klippstein *et al.*, WP-10-E-BPA-24, at 3. The Big 10 projects are generally older hydro projects, and the embedded cost of these projects is low as compared to BPA's other embedded costs. BPA's power customers must pay all of BPA's embedded cost, including CGS and other significant costs.

NWG argues that BPA should not allocate the embedded cost and the variable cost to the Wind Balancing Service rate. This issue is discussed in detail in section 13.4.2 Issues 8 and 9. For the issue at hand, it is clear that allocating only the incremental cost imposed by the wind generators to the Wind Balancing Service rate is not consistent with the principle of cost causation and would constitute a cost shift to BPA's power customers.

<u>Decision</u>

Providing capacity reserves to integrate wind generators has become a significant firm use of the FCRPS. Pricing the Wind Balancing Service at only the incremental costs of providing this service would not be consistent with the principle of cost causation. The Wind Balancing Service rate cost allocation will include an appropriate allocation of the embedded cost of the system.

Issue 6

Whether the combination of charges, penalties, and operational requirements directed specifically at wind generators inappropriately shifts all risks to the wind generators.

Parties' Positions

Iberdrola asserts that the combination of Staff's proposed Wind Balancing Service rate, penalties, and operational requirements shifts virtually all of the risk from BPA to wind generators, and seeks to ensure that all possible outcomes associated with variability of wind are covered by wind generators. Iberdrola Br., WP-10-B-IR-01, at 24.

PPC *et al.* contend that with the large amount of wind generation interconnecting to the BPA system, Staff has proposed appropriate steps in this rate case to identify and recover the costs of balancing wind generation. PPC *et al.*, WP-10-B-JP11-01, at 28.

BPA Staff's Position

The Wind Balancing Service rate proposal is based on cost causation and is an appropriate rate for wind generators. Mainzer *et al.*, WP-10-E-BPA-41, at 3, 28. The other rate design elements about which Iberdrola has expressed concern, persistent deviation and Generation Imbalance Band 2, are consistent with reliable operations and necessary to encourage accurate scheduling behavior. *See* chapter 20 of this ROD.

Evaluation of Positions

Iberdrola urges Bonneville not to adopt policies and rates that would discourage renewable resource development and inappropriately inflate the delivered cost of wind energy in the region. Iberdrola Br., WP-10-B-IR-01, at 24. Iberdrola claims that Staff's proposed combination of charges, penalties, and operational requirements directed specifically at wind generation will skew the true cost of renewable energy expansion, make it difficult for the region to meet its clean energy goals, and force Iberdrola to consider alternative actions that may not be the most efficient use of the regional transmission system. *Id*.

With respect to the proposed "charges" for Wind Balancing Service, Staff has identified cost causation as the fundamental principle used in allocating the costs of the system to the uses of the system. Mainzer *et al.*, WP-10-E-BPA-41, at 3. Providing generation inputs to support provision of ancillary services and control area services are a necessary use of system generation to support reliable operation. Mainzer *et al.*, WP-10-E-BPA-22, at 2. Prior to 2009, BPA allocated the costs of capacity associated with Regulating Reserves and Operating Reserves necessary to maintain the reliability of the transmission system and support the variability of loads and generation. In 2008, in the WI-09 rate proceeding, BPA identified additional capacity uses of the system resulting from increasing amounts of wind generation interconnected in the BPA Balancing Authority. *Id*. at 15-16. Staff has identified three types of within-hour balancing reserves that are used to provide the different types of generation inputs: regulating reserves, following reserves, and imbalance reserves. *Id*. at 7. Staff forecasts the use of each of these types of within-hour reserves for the rate period. McManus *et al.*, WP-10-BPA-E-23. Staff then proposes to allocate costs to the uses of the system, using a common methodology for the costs of generation inputs for all uses. Mainzer *et al.*, WP-10-E-BPA-22, at 7-8; Mainzer *et al.*, WP-10-BPA-E-41, at 28.

PPC *et al.* support Staff's effort to capture all legitimate and verifiable costs of integrating wind generation in the BPA Balancing Authority. PPC *et al.*, WP-10-B-JP11-01, at 29. PPC *et al.* note equity concerns and state that allocating these costs to wind generation allows the costs to be reflected in the price of wind power, directly or indirectly. In this way, PPC *et al.* state, the true costs of the wind generation are revealed to the marketplace and BPA avoids according a material, economic advantage to wind resources competing to make sales in the market. *Id.* BPA's public power customers support BPA's use of a common methodology to allocate costs of generation inputs for all uses. *Id.* at 30.

Iberdrola is concerned that BPA's scaling methodology overestimates the amount of reserves necessary to manage within-hour variation of the wind fleet. Iberdrola Br., WP-10-B-IR-01, at 11. Iberdrola states that adopting an estimate of scheduling accuracy greater than 37.5 minutes would overestimate the amount of reserves necessary to manage within-hour variation of the wind fleet. *Id.* at 25. Iberdrola urges BPA to facilitate and allow wind generators to self-supply one or more components of within-hour balancing reserves if BPA elects not to follow Iberdrola's recommendations on these issues. *Id.* at 25.

Iberdrola's concern that errors in BPA's reserve forecast methodology will result in BPA holding and charging wind generators for excessive reserves are complaints about the methodologies themselves. BPA addresses those concerns in section 13.3.

Iberdrola also lists penalties proposed by Staff as being part of this shifting of risk to wind generators. With respect to the "penalties" proposed by Staff, Iberdrola's concern about shifting risk to wind generators fails to acknowledge the nature of penalty rates. A penalty rate applies to particular actions or circumstances described in the rate schedule. A customer or its actions satisfy the criteria that result in application of a penalty or it does not, and the actions of one customer do not shift the risk of a penalty applying to another customer class. Specific issues regarding persistent deviation and Generation Imbalance are addressed in other sections of the ROD; *see* Chapter 20 and section 13.4 Issue 7.

With respect to the new operational requirements proposed by Staff, the record indicates that the wind generators are urging BPA to allocate that risk to the wind fleet in exchange for lower rates. Iberdrola Br., WP-10-B-IR-01, at 12; NWG Br., WP-10-B-NG-01, at 13; Hall, Oral Tr. at 48; Skidmore, Oral Tr. at 64; Skidmore, Oral Tr. at 168. Outside this rate proceeding, BPA has proposed a new set of reliability and operational requirements, referred to as DSO 216, that are designed to meet multiple objectives of ensuring reliability, improving wind scheduling accuracy, and limiting the amount of FCRPS capacity reserved for wind balancing. Mainzer *et al.*, WP-10-E-BPA-22, at 20. These operating requirements would enable BPA to instruct wind generators to reduce output when BPA is close to exhausting the total amount of *dec* reserves for balancing, and revise transmission schedules within the hour when actual wind generation is far below schedules and BPA is close to exhausting total *inc* reserves. Mainzer *et al.*, WP-10-E-BPA-22, at 20. To the extent that variation in wind fleet generation causes BPA to exhaust its balancing reserves, the risk of operational measures to preserve system reliability in that situation is properly shifted to the wind fleet.

Iberdrola supports the adoption of operational solutions to reduce the need for balancing reserves. Skidmore, Oral Tr. at 64. NWG also supports the adoption of these operational solutions. Hall, Oral Tr. at 48; NWG Br., WP-10-B-NG-01, at 13. Iberdrola's support of these requirements is based on an expectation that the amount of reserves held by BPA will be reduced, because BPA could assume that the wind fleet would schedule more accurately for purposes of the generation reserve forecast. Iberdrola Br., WP-10-E-IR-02, at 7. When asked in oral argument if Iberdrola would prefer fewer curtailments or a lower rate, Iberdrola stated it preferred a lower rate based on its belief it can schedule to a level of accuracy equal to 30-minute persistence schedules. Skidmore, Oral Tr. at 62.

PPC *et al.* argue that levels of reserve requirements should not be based on assumptions of future improved scheduling accuracy. PPC *et al.*, WP-10-B-JP11-01, at 36-37. PPC *et al.* are concerned that BPA will be required to set aside additional amounts of reserves if improvements do not materialize. *Id*. PPC *et al.* are concerned that under-forecasting the level of reserves will place greater risk to the successful implementation of BPA's proposed operational solutions described as DSO 216. *Id*. The issues of the appropriate scheduling accuracy assumption and the appropriate reserve forecast are addressed in section 13.3.2.3 below.

Iberdrola's arguments about shifting all risk to wind generators distill to the concern that BPA will forecast a reserve requirement in excess of the amount that is necessary, and wind generators will bear the cost. BPA's "charges" for Wind Balancing Services are based on cost causation principles, and BPA's penalties are based on deterring particular actions. The risk that is shifted to wind generators associated with these proposals is risk imposed on the system by wind generators. The wind generators are better situated to manage that risk than BPA or BPA's other customers. BPA's new operational requirements are based on the potential for variation in wind generation to exhaust BPA's balancing reserves. The decision between 30- and 45-minute persistence schedules is an issue of quality of service versus a lower rate. The risk of operational measures needed to preserve system reliability in that situation is a risk that is properly allocated to the wind fleet and that the wind fleet apparently is willing to accept.

Decision

BPA's charges to integrate wind are based on cost causation and shift risk to wind generators where the wind generator is in the best position to manage the risk.

Issue 7

Whether there is a legal basis for reducing power rates with revenues from providing generation inputs for ancillary services and control area services.

Parties' Positions

MSR states that there is no legal basis for developing transmission charges that offset power rates. MSR Br., WP-10-B-MS-01, at 9.

BPA Staff's Position

This is a legal issue, and Staff has taken no position on the record.

Evaluation of Positions

MSR alleges that there is no legal basis to establish a transmission charge as an offset to power rates. Even though MSR provides no facts or legal argument to back up its allegation, MSR is mistaken as to a lack of a legal basis for developing Ancillary Service and control area service rates based on assigning generation costs associated with providing these services. Allocating costs to these generation inputs and assigning these costs to Transmission Services to recover through its rates is consistent with cost causation, Commission ratemaking policy, and standard utility practice. The costs assigned to Transmission Services are based on the forecast of capacity reserves Transmission Services will need to maintain the reliability of its system. Under BPA's ratemaking structure, power customers are responsible for all power costs, so it is rational under basic ratemaking principles that the power revenue requirement would be reduced when certain power costs are assigned to transmission rates. For further discussion regarding the assignment of generation costs to Transmission Services, *see* section 20.1.3.2, Issue 2.

Decision

There is a legal basis for assigning generation costs associated with providing a transmission service to Transmission Services and reducing the Power Services revenue requirement by the amount of the assigned costs.

Issue 8

Whether the FCRPS has sufficient reserves to meet the forecast needs during the rate period and whether augmentation will be necessary to support wind generation and other commitments.

Parties' Positions

Snohomish states that the level of reserves expected to be available from the FCRPS for the FY 2010-2011 rate period appears to be unrealistic based on the Preliminary Needs Assessment. Snohomish Br., WP-10-B-SN-01, at 5. Snohomish claims that for BPA to support development of additional wind resources, the FCRPS will need to be augmented, and wind developers should pay the full costs associated with that augmentation. *Id*. at 5-6.

BPA Staff's Position

Staff's original assumption for preparing the Initial Proposal was that all reserve needs would be met by the FCRPS for the FY 2010-2011 rate period. Klippstein *et al.*, WP-10-E-BPA-24, at 3. Based on the Preliminary Needs Assessment, if other inputs to the wind balancing rate were not changing, Staff might agree with Snohomish's conclusion. However, based on the latest analysis, Staff's original assumption that the FCRPS will have sufficient reserves to support the forecast capacity obligation during the FY 2010-2011 rate period is still supportable. McManus *et al.*, WP-10-E-BPA-42, at 27.

Evaluation of Positions

In the Initial Proposal, Staff assumes that the FCRPS will have enough reserves to meet the balancing needs of wind and load during the FY 2010-2011 rate period. Klippstein *et al.*, WP-10-E-BPA-24, at 3. The Preliminary Needs Assessment was published in early March 2009, more than a month after the Initial Proposal. *See* Dragoon, WP-10-E-NG-01-AT02. The Preliminary Needs Assessment uses the same wind assumptions as the Initial Proposal and projects that the FCRPS may not have enough *dec* reserve capability by the end of the rate period. *See* BPA's 2009 Preliminary Needs Assessment, WP-10-E-NG-01-AT02 at 7, 31-32. These assumptions include a two-hour persistence scheduling accuracy and the original estimate of installed wind for the rate period. *Id*. at 7, 34-35. Additionally, the Preliminary Needs Assessment shows a notable increase in violations of non-power operating constraints of the FCRPS when *inc* reserves increase beyond 1,179 MW and *dec* reserves increase beyond 1,453 MW. *Id*. at 35, 44.

Snohomish is the only party that raises this issue in its Initial Brief. Snohomish Br., WP-10-B-SN-01, at 5. However, two additional parties, NWG and PPC *et al.*, raise this issue in their testimony. Dragoon, WP-10-E-NG-01, at 30; Baker *et al.*, WP-10-E-JP6-01, at 7. NWG argues that BPA's cost calculations assume that BPA will be able to provide services that require reserves from FCRPS resources, but the Preliminary Needs Assessment suggests that BPA may not be able to fully provide all of these reserves. Dragoon, WP-10-E-NG-01, at 30. PPC *et al.* also reference BPA's Preliminary Needs Assessment and argue that Approach C of the Preliminary Needs Assessment concludes that BPA does not have sufficient balancing reserves to integrate the amount of wind generation that is forecast to be interconnected in the Balancing Authority Area in FY 2011. Baker *et al.*, WP-10-E-JP6-01, at 7.

Staff addresses the results of the Preliminary Needs Assessment in rebuttal testimony:

> The Preliminary Needs Assessment, as its title indicates, is preliminary and is currently being reviewed in the region. BPA's Preliminary Needs Assessment breaks new ground by assessing the capacity and flexibility needs of the Federal system in new ways. If no changes occur in scheduling accuracy or operational protocols, parties' concerns about the ability of BPA to meet reserve needs may be appropriate. BPA is concerned about ensuring that the Federal system has the capability to meet the many obligations and operating constraints it faces and thus included balancing reserve as one of the elements in the analysis. In the conclusion of the Wind Reserve Impact Study section, the authors state that the results "indicate a system condition where meeting the reserve requirements and satisfying other power and non-power requirements would be extremely difficult." Baker *et al.*, WP-10-E-JP6-02, Attachment 1, at 44. This analysis was based on the WIT study of reserve needs during the FY 2010-2011 rate period.

Mainzer *et al.*, WP-10-E-BPA-41, at 28-29.

The basic assumptions about the amount of wind interconnecting in the rate period and the persistence scheduling accuracy of wind generators have changed since the Initial Proposal and the posting of the Preliminary Needs Assessment. *Id*. at 29. The persistence scheduling accuracy of wind generators that will be used in the final studies is less than the two-hour persistence assumption in the Initial Proposal, and the forecast of installed wind generation has also been reduced. McManus *et al.*, WP-10-E-BPA-42, at 12-16; *see* sections 13.3.2.3 and 13.3.2.4 below for further discussion of these changes. With the updated installed wind generation forecast and assuming a 60-minute persistence level, the total reserve requirement for load and wind in the Balancing Authority Area is forecast at 1,089 MW of *inc* reserves and 1,340 MW of *dec* reserves, both values less than used in the Initial Proposal. McManus *et al.*, WP-10-E-BPA-42, at 27.

Assuming a lower persistence scheduling accuracy and relying on DSO 216 to limit the amount of reserves BPA commits to balancing wind and load significantly reduces the amount of reserves needed during the rate period. Mainzer *et al.*, WP-10-E-BPA-22, at 20-22; Mainzer *et al.*, WP-10-E-BPA-41, at 30-39. In addition, the new methodology for calculating total reserves and the new load forecast assumptions reduce the amount of total reserve need for the rate period. McManus *et al.*, WP-10-E-BPA-42, at 22-27. Based on these changes that have been made since the Initial Proposal, the current forecast of the reserve needs can be met without augmenting the FCRPS in the FY 2010-2011 rate period.

Decision

The FCRPS has sufficient reserves to meet the forecast needs during the FY 2010-2011 rate period.

Issue 9

Whether BPA should modify the revenue forecast for the cost allocation associated with the Wind Balancing Service rate in anticipation of significant self-supply or wind generation moving to a nested balancing area.

Parties' Positions

NWG states that BPA should be prepared to adjust the Wind Balancing Service rate mid-rate period to account for significant changes in the number of wind generators taking service from BPA. NWG Br., WP-10-B-NG-01, at 40-41. According to NWG, significant changes may occur because one or more large wind generators may decide to self-supply part or all of their reserve needs. *Id*.

Iberdrola states that the Wind Balancing Service rate design should allow for decreases in the rate level to reflect reductions in the reserves requirement resulting from self-supply during the rate period. Iberdrola Br., WP-10-B-IR-01, at 17-18. Iberdrola also states that if the Wind Balancing Service rate increases more than 50 percent over the current WI-09 rate, Iberdrola plans to either self-supply some portion of its reserve need or form its own nested control area. *Id*. at 6.

PPC *et al.* respond to BPA's proposal in the Draft ROD in its Brief on Exceptions, stating that BPA should not account for the risk of under-recovery associated with self-supply in the final risk analysis study. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 12-14. PPC *et al.* argue that they are prevented from making informed comments on this proposal because BPA has not quantified the risk of self supply or explained how BPA would account for self-supply in the risk analysis. *Id*. at 12-13. PPC *et al.* suggest that BPA cannot formulate a reasonable assumption based on the evidence in the record, and PPC *et al.* will have no ability to comment or test BPA's assumptions, which is a right that is afforded under the Northwest Power Act. *Id*. at 13. PPC *et al.* claim that because BPA's proposal is made very late in the rate proceeding, BPA should wait until after the terms and conditions for self-supply have been developed and wind generators have committed to self-supply to determine in a supplemental 7(i) proceeding the rate impacts of self-supply. *Id*. at 14.

BPA Staff's Position

Iberdrola and NWG raised the unbundling issue for the first time in their Initial Briefs, so Staff has not responded to this issue in the record.

Evaluation of Positions

The amount of self-supply reflected in the reserve forecast is based on the best information available at the time of the rebuttal testimony. The only adjustment that was made in anticipation of self-supply is based on Puget Sound Energy's current request to move its wind generation out of the BPA Balancing Authority and into its own Balancing Authority. McManus *et al.*, WP-10-E-BPA-42, at 3.

The issues of a significant amount of self-supply or Iberdrola moving its wind fleet into its own Balancing Authority Area were not raised until Initial Briefs, so there is nothing in testimony to support or refute the assertion that Iberdrola will provide all or a portion of the capacity reserves needed to support its needs. Furthermore, the record lacks testimony or evidence regarding the feasibility of self-supply during the rate period or the technical requirements associated with forming a new Balancing Authority or withdrawing from the BPA Balancing Authority. Iberdrola asserts in its brief that it will either self-supply or leave the BPA Balancing Authority, Iberdrola Br., WP-10-B-IR-01, at 5-6, without knowing the level of BPA's final rate for the Wind Balancing Service. In addition, the technical and commercial requirements to self-supply an equivalent service to BPA have not been determined, because the business practices and protocols for self-supply have yet to be determined. Whether any wind generators will be able to self-supply during the rate period is still an open question, with several technical and economic issues still unresolved, although BPA is committed to providing a self-supply option during the rate period. For a full discussion of the hurdles that Iberdrola may face in implementing partial self-supply or forming its own Balancing Authority, *see* Chapter 20 of this ROD.

In assessing whether BPA should modify its generation reserve forecast or the cost allocation associated with the Wind Balancing Service rate, BPA must weigh the probability of a significant amount of self-supply or wind generators leaving the BPA Balancing Authority. Based on Iberdrola's declaration on self-supply, it would be speculative at best to assume a specific amount of self-supply when the technical aspects and amounts are virtually unknown. If there is a significant amount of self-supply, it likely would not occur until well into the rate period, with implementation beginning on October 1, 2010. Forecasting an expected amount of self-supply based on the facts in the record is not supportable.

Another option would be a rate adjustment that would become effective if a certain amount of wind did self-supply or leave the BPA Balancing Authority. It appears that NWG is advocating for an adjustment to the wind rate if there is significant self-supply. NWG Br., WP-10-B-NG-01, at 40-41. As stated above, this issue is discussed in Chapter 20 of this ROD. The other consideration for this option would be an upward adjustment to power rates at the same time to account for the under-recovery of revenues that would result from significant self-supply. This could be described as a wind CRAC. This option is not appealing; again, the possibility of a significant amount of wind self-supply is speculative, and if it does occur, it will not happen until late in the rate period, and no wind CRAC proposal is on the record for the Administrator to consider. Another option would entail a subsequent section 7(i) proceeding to modify rates, and as BPA discusses in Chapter 14 regarding a mid-rate period consideration of a stepped rate, the competing workload all but precludes BPA from instituting another 7(i) proceeding.

Given the unknowns regarding technical requirements, cost, contractual and business practice development, and economics for each wind generator assessing whether to self-supply, a more practical approach to the issue of accounting for the potential of significant self-supply and the possible revenue under-recovery associated with self-supply is to include this potential in the final risk analysis. The risk analysis in the Initial Proposal included an element of risk associated with BPA under- or over-forecasting the amount of wind generation that would interconnect during the rate period. Risk Analysis and Mitigation Study, WP-10-E-BPA-04, at 34-36. Based on the assertions in Iberdrola's brief and the other information discussed above, the final risk analysis can use a similar model to assess the amount of revenue risk due to the possibility of self-supply, which would reduce BPA's revenue. BPA does not want to discourage self-supply or other options for serving wind generators' capacity reserve needs that are consistent with the reliable operation of BPA's system. However, based on the current situation, it appears that BPA should not forecast a significant amount of self-supply or a significant amount of wind generation leaving the BPA Balancing Authority Area in this rate period. BPA and parties will be better able to assess the self-supply situation for the next rate case (BPA-12) and reflect it accordingly at that time.

PPC *et al.* argue against inclusion, in the final risk analysis, of the risk of under-recovery associated with self-supply. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 12-14. PPC *et al.* point out that BPA's proposal is made very late in the rate case process. *Id.* at 14. BPA agrees that this proposal is something new included in the Draft ROD, but by the same token, the discussion of a significant amount of self-supply was not introduced into the record until Iberdrola and NWG discussed the possibility in their Initial Briefs. Iberdrola Br., WP-10-B-IR-01, at 4-5; NWG Br., WP-10-B-NG-01, at 40-41. Despite the timing of these new developments, BPA believes it is important to address this issue in this rate process, and the appropriate mechanism to address the risk of under-recovery due to self-supply is the final risk study.

As described above, BPA addressed the risk associated with the accuracy of the forecast of installed wind generation in the Initial Proposal, and the Final Proposal risk evaluation for self-supply will be very similar. PPC *et al.* argue that BPA cannot formulate a reasonable assumption based on evidence in the record, and there is no evidence in the record regarding the feasibility of self-supply or the commitment of wind generators to self-supply. PPC *et al.* Br.Ex, WP-10-R-

JP12-01, at 13. As noted above, BPA agrees that the record is not well developed on this issue, but BPA has committed to make self-supply a feasible option during the rate period (*see* section 13.4.2, Issue 11, and Chapter 20). Iberdrola has stated that it intends to pursue self-supply for some of its balancing needs as these options become available (*see* Iberdrola Br., WP-10-B-IR-01, at 5), and the amount of Iberdrola's installed wind generation capacity can be derived from the record. *See* Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, Table 2.1 at 26-30. This information indicates that there is some probability that Iberdrola will do some amount of self-supply in 2011, and this is enough information to allow for a risk analysis in the Final Risk Analysis and Mitigation Study.

As noted above, the possibility of a significant amount of self-supply did not arise until very late in the rate case process. BPA is committed to working out the business practices and technical details to make self-supply feasible by the beginning of the second year of the rate period. PPC *et al.* state that they strongly support self-supply of balancing reserves and want BPA and the customers to arrive at a durable and commercially feasible proposal for accomplishing this objective. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 13-14. PPC *et al.* object to BPA including a risk analysis of under-recovery from self-supply, because PPC *et al.* are unable to comment on or test BPA's assumptions. *Id.* at 13. But PPC *et al.* do not object to BPA's commitment to enable self-supply during the rate period or the fact that the record is not more fully developed on this issue, even though both of these issues arose at virtually the same point in the rate case process, and many of the same details are absent from the record. Because BPA has decided to support the development of self-supply, it is prudent to include a risk analysis for the rate period of the impacts that spring from that decision.

PPC *et al.* argue that after the terms and conditions for self-supply have been developed and wind generators have committed to self-supply, BPA needs to determine the rate impacts of self-supply in a supplemental 7(i) proceeding. *Id.* at 14. As discussed above, the competing workload all but precludes BPA from instituting another 7(i) proceeding. In addition, establishing the terms and conditions and developing the technical solutions needed to enable significant self-supply will most likely consume most of the first year of the rate period. If BPA must then hold a supplemental 7(i) process, which could easily take six months, prior to allowing self-supply, the rate period would be virtually over before any significant self-supply commences. The extra process of a supplemental 7(i) is not consistent with the goal of enabling significant self-supply options during this rate period or the promotion of development of renewable resources, which PPC *et al.* support.

Including risk analysis on the potential for under-recovery due to self-supply in the final Risk Analysis and Mitigation Study is the prudent approach to this issue. Ideally, there would be an opportunity for review of BPA's assumptions and inputs into this analysis, but these issues have arisen too late in the rate case schedule to allow for such review. The potential for under-recovery due to self-supply is not a significant risk, and because it is not likely to occur until the second year of the rate period, there is not a substantial amount of cost recovery at risk. Because BPA is including no PNRR in the final rates, this risk analysis will have no effect on any power rates and will have only a minor impact on the probability of a CRAC or a DDC adjustment.

Decision

BPA will not modify the revenue forecast for the cost allocation associated with the Wind Balancing Service rate in anticipation of significant self-supply or wind generators moving to a nested balancing area. BPA will account for this risk in the final risk analysis. However, this risk analysis will have no effect on any power rates and will have only a minor impact on the probability of a CRAC or a DDC adjustment.

Issue 10

Whether the amount of reserves set aside by BPA for the Wind Balancing Service will be limited to the amount forecast in the rate case, and whether BPA should make data available to verify that the amount of reserves being set aside is consistent with the rate case forecast.

Parties' Positions

PPC *et al.* state that nothing prohibits BPA from holding amounts of reserves in excess of the rate case forecast for Wind Balancing Service and that BPA will be pressured to hold excess reserves if it is ordering feathering and curtailment under DSO 216 too often. PPC *et al*. Br., WP-10-B-JP11-01, at 36; PPC *et al*. Br. Ex., WP-10-R-JP12-01, at 17-18. PPC *et al.* also state that BPA should take steps to demonstrate that it is not holding excess reserves at the expense of requirements customers. PPC *et al*. Br. Ex., WP-10-R-JP12-01, at 17-18.

NWG urges BPA to implement a transparent communication and documentation process related to application of DSO 216. NWG Br. Ex., WP-10-R-NG-01, at 9.

Iberdrola states that it is important that implementation of DSO 216 occur in a transparent and collaborative process. Iberdrola Br. Ex., WP-10-R-IR-01, at 9.

BPA Staff's Position

BPA will set aside an amount of reserves consistent with the forecast using the rate case methodology and assumptions for the wind generators on BPA's system, and BPA will plan to that amount of reserves for purposes of applying DSO 216. Mainzer *et al.*, WP-10-E-BPA-41, at 29-30, 36. Implementation of DSO 216 should occur in a transparent and collaborative manner.

Evaluation of Positions

PPC *et al.* state a variety of concerns related to BPA potentially holding more reserves for balancing wind generation than the amount BPA forecasts in the rate case. Section 13.3.2.3 addresses the arguments of PPC *et al.* regarding the alleged cost shift associated with holding reserves in excess of the forecast amount. As described in that section, BPA intends to set aside an amount of reserves consistent with the amount forecast using the rate case methodology and assumptions for the amount of installed wind capacity on the BPA system. Mainzer *et al.*, WP-10-E-BPA-41, at 29-30, 36. The reserve forecasts provided by Staff in this proceeding include assumptions about the amount of installed wind capacity that will be on-line in each month of the rate period. *See* Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at Table 2.1; McManus *et al.*, WP-10-E-BPA-42-E01, at Exhibit 13. BPA intends to set aside reserves consistent with the forecast for the actual amount of wind capacity on-line in a particular month rather than the amount that Staff assumed for any particular month. BPA will implement DSO 216 when it has deployed 90 percent of the amount of reserves being held. *See* Mainzer *et al.*, WP-10-E-BPA-41, at 29-30, 36. DSO 216 contemplates that there may be unforeseen conditions or cases of extreme use when provision of reserves must be constrained to a lower amount to protect operation of the hydro system. *Id.* at 30. BPA will not be motivated to set aside reserves in excess of the forecast, because of risks to non-power operations and the costs of carrying and providing additional reserves. *Id.* at 34.

BPA agrees that DSO 216 should be implemented in a transparent and collaborative manner. BPA is open to providing information that helps ensure transparency and allows stakeholders to understand the application of the DSO. PPC *et al.* identify specific information, such as total reserves held, total reserves deployed, aggregate load, aggregate wind generation, and associated capacity factors, that it asks BPA to provide as part of implementation of DSO 216. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 18. Although much of the information that PPC *et al.* identify is the type of data that BPA already makes publicly available, and BPA is willing to provide that type of information, BPA encourages discussion in the WIT forum regarding the specific types of information that stakeholders would like BPA to provide.

Decision

The amount of reserve set aside by BPA for the Wind Balancing Service will be limited to amounts forecast using the rate case methodology. BPA will make data available for stakeholders to verify the amount of reserves being set aside.

13.3 Reserve Forecast

13.3.1 Introduction

The generation reserve forecast estimates the amount of reserves that BPA needs in order to provide within-hour balancing services during the rate period. BPA must maintain load-resource balance within the hour to preserve system reliability and comply with NERC and WECC reliability standards. Power Services designates FCRPS generating resources under AGC to provide the generation inputs necessary to supply within-hour balancing services. If load increases, or generation decreases, the AGC system increases (*inc*) generation. If load decreases, or generation increases, the AGC system decreases (*dec*) generation. The cumulative *inc* and *dec* generation required to maintain load-resource balance is the basis for the reserves for within-hour balancing services.

BPA's reserve requirement consists of three components: regulating reserve, following reserve, and imbalance reserve. For purposes of the reserve forecast, regulating reserve compensates for moment-to-moment differences between generation and load. Following reserve compensates for larger differences occurring over longer periods of time during the hour. The imbalance component compensates for differences between the generator's schedule and the generation during an hour (*i.e.*, imbalance). The imbalance component differs from Generation Imbalance or Energy Imbalance.

Staff has developed a methodology to forecast the reserve necessary to provide within-hour balancing services during the rate period. Discussion of the primary issues parties have raised with respect to the methodology are organized below according to six topics: 1) the estimate of installed wind capacity during the rate period; 2) scaling of future wind generation; 3) scheduling accuracy assumption; 4) total reserve requirement calculation; 5) load forecast assumption; and 6) allocation of total reserve requirement between wind and load.

13.3.2 Issues

13.3.2.1 Estimate of Installed Wind Capacity

The reserve forecast methodology estimates the total installed capacity of the existing and future wind projects expected to be online during the rate period. Staff estimated a rate period average of 3,739 MW in the Initial Proposal and reduced that estimate to 3,053 MW in rebuttal testimony.

Issue 1

Whether BPA should adopt a specific adjustment to the estimate of installed capacity to account for current economic conditions.

Parties' Positions

In direct testimony, Iberdrola, NWG, and Cowlitz urge BPA to adjust the Initial Proposal estimate of the installed capacity of wind generation that will be online during the rate period to account for current economic conditions. Froese *et al.*, WP-10-E-IR-01-CC01, at 25; Dragoon, WP-10-E-NG-01, at 17; Skeahan *et al.*, WP-10-E-CO-01, at 4. The parties do not propose or quantify a specific adjustment.

In its brief, NWG states that it supports the change in the estimate of installed capacity in Staff's rebuttal testimony; NWG does not address a specific adjustment related to economic conditions. NWG Br., WP-10-B-NG-01, at 16-17. Iberdrola supports adoption of the updated estimated in Staff's rebuttal testimony. Iberdrola Br. Ex., WP-10-R-IR-01, at 7. Cowlitz suggests that BPA make a specific adjustment to account for the future, within-rate-period effects of the current economic downturn, including the effect of difficulties in accessing capital on the pace at which developers complete and energize wind projects. Cowlitz Br., WP-10-B-CO-01, at 8. Cowlitz states that one method to account for the future effects of the economic downturn would be to extrapolate through the rate period the rate of reduction in forecast interconnections between July 15, 2008, and date of issuance of the Draft ROD. *Id.*

BPA Staff's Position

Staff's rebuttal testimony includes an updated estimate of the installed capacity expected to be online during the rate period. Staff estimates an average installed capacity of 3,053 MW for the rate period, which is 686 MW less than the 3,739 MW average estimated in the Initial Proposal. McManus *et al.*, WP-10-E-BPA-42, at 2. Staff does not make a specific, quantitative adjustment to the estimate to account for economic conditions. The estimate relies on information provided directly by the wind developers, which should already account for any impact of current economic conditions. *Id*. at 4.

Evaluation of Positions

Cowlitz appears to be the only party that continues to support a specific adjustment to Staff's updated estimate of installed wind capacity to reflect current economic conditions. Although Cowlitz suggests a method for making such an adjustment, the record contains no evidence to support an adjustment based on Cowlitz's proposal. No other party proposes a specific adjustment, and the record lacks evidence to support any such adjustment in general.

Staff's rebuttal testimony convincingly describes how the estimate of installed capacity accounts for the impact of current economic conditions without a specific adjustment, because the estimate relies, in part, on information received directly from project developers regarding the status of projects under development. McManus *et al.*, WP-10-E-BPA-42, at 2. A specific adjustment is unjustified under these circumstances.

Decision

BPA will not adopt a specific adjustment to the estimate of installed wind capacity during the rate period to account for current economic conditions.

Issue 2

Whether BPA should adopt the updated estimate of installed wind capacity for use in the generation reserve forecast.

Parties' Positions

In testimony, Iberdrola, NWG, and Cowlitz urge BPA to update the Initial Proposal estimate of the installed capacity of wind generation that will be online during the rate period. Froese *et al.*, WP-10-E-IR-10-CC01, at 25; Dragoon, WP-10-E-NG-01, at 17; Skeahan *et al.*, WP-10-E-CO-01, at 4. NWG, PPC *et al.*, and Iberdrola support adopting the updated estimate in Staff's rebuttal testimony. NWG Br., WP-10-B-NG-01, at 17; PPC *et al.* Br., WP-10-B-JP11-01, at 31-32; Iberdrola Br. Ex., WP-10-R-IR-01, at 7-8.

BPA Staff's Position

Staff supports adopting the updated estimate of installed capacity in its rebuttal testimony. McManus *et al.*, WP-10-E-BPA-42, at 2-3.

Evaluation of Positions

Staff states in the Initial Proposal that it would update the estimate of the installed wind capacity during the rate period prior to the final studies. McManus *et al.*, WP-10-E-BPA-23, at 11. Staff provides the update in rebuttal testimony, and it is a significant reduction from the initial estimate. McManus *et al.*, WP-10-E-BPA-42, at 2-3. Staff's updated estimate reflects the most recent information on this topic, and it will be adopted.

Decision

BPA will adopt Staff's updated estimate of installed wind capacity for use in the generation reserve forecast.

13.3.2.2 Scaling of Future Wind Generation

Staff estimates the output of the amount of installed wind capacity expected during the rate period using data regarding the time delays (*i.e.*, "leads" or "lags") between existing projects and the location of future projects within the Balancing Authority Area. BPA obtained data regarding typical leads and lags from the wind forecasting and assessment company 3TIER. BPA adjusted the 3TIER data if it included zero values (no lead or lag) to reflect a 10-20 minute lead or lag based on Staff's observations of the area in question.

Using the lead and lag data and actual generation data from existing facilities, Staff "scales" the generation of future wind facilities. Staff uses more than one existing project to scale the output of a future project in the majority of cases. Staff develops the scaled output of future facilities by multiplying the existing facility's generation by the planned facility capacity and dividing by the existing wind project capacity. Staff then time shifts the output based on the lead and lag between the existing facility and the future facility. Staff scales the output of each future wind facility expected to be online during the rate period using this method.

Issue 1

Whether the 3TIER dataset is reliable and adequate for use in the scaling analysis.

Parties' Positions

Iberdrola criticizes the 3TIER dataset used for the scaling analysis and the manner in which the data was used. Iberdrola Br., WP-10-B-IR-01, at 8-9. Iberdrola maintains that 3TIER's analysis was "highly subjective," that 3TIER did not understand how Staff intended to use the 3TIER dataset, and that Staff did not understand what the dataset represents. *Id*. According to Iberdrola, "this small and misunderstood set of data is a severely inadequate basis for this important aspect of the wind integration charge." *Id*.

PPC *et al.* note that Iberdrola and NWG have not proposed an alternative to the 3TIER data for use in this case. PPC *et al.* Br., WP-10-B-JP11-01, at 32-33.

BPA Staff's Position

3TIER is a reputable renewable energy forecasting and assessment company. McManus *et al.*, WP-10-E-BPA-42, at 5. Without having a real-time monitoring system for all wind in the area in which new wind facilities are to be built, the 3TIER dataset is the best available. *Id*. The 3TIER data is the same type of data that BPA requested from 3TIER to develop the reserve forecast for the WI-09 rate. WP-10-E-IR-03 (Response to Data Request No. IR-BPA-19) (*see* May 9, 2008 email from Bart McManus, BPA, to Cameron Potter, 3TIER, requesting "the same information as I received last year from you concerning prevalent delays in wind patterns between the wind farms."). Staff disagrees that the 3TIER dataset is unreliable or inadequate for use in the scaling analysis, and there was no misunderstanding between Staff and 3TIER about this information.

Evaluation of Positions

Iberdrola does not dispute that 3TIER is a reputable renewable energy forecasting company that is capable of providing information upon which a scaling analysis might be performed. Iberdrola Br., WP-10-B-IR-01, at 8-9. Iberdrola claims, however, that this particular 3TIER analysis is too subjective and that Staff and 3TIER either misunderstood or did not know the nature of the information provided and the purpose for which it was to be used. *Id.* Iberdrola's testimony generally criticizes the "robustness" of the 3TIER data as well. Froese *et al.*, WP-10-E-IR-01-CC01, at 22.

Iberdrola acknowledges that the scaling analysis is an important part of the reserve forecast methodology and that the 3TIER dataset is the starting point for the scaling analysis. Iberdrola Br., WP-10-B-IR-01, at 7. Iberdrola nevertheless appears to suggest that BPA should invalidate the 3TIER dataset as a whole because of the alleged flaws. *Id.* at 9. The record contains little evidence to support such a sweeping action. Iberdrola raises its claims about subjectivity of the 3TIER analysis and misunderstandings between BPA and 3TIER for the first time in its Initial Brief. *Id.* at 8-9. These specific criticisms appear to be based on interpretations and assumptions about the information 3TIER provided, and no party has had an opportunity to conduct discovery, provide evidence, or otherwise respond to these claims. BPA will evaluate the validity of the 3TIER data based on the evidence in the record, but claims that go beyond the face of that evidence are assigned little weight under these circumstances.

When Iberdrola addressed the 3TIER data in its direct testimony, its criticism was not that the analysis was too subjective or that BPA misused the data because of misunderstandings, but rather that the 3TIER data was insufficiently "robust":

> Bonneville has relied extensively on a data set produced by a mesoscale numerical weather prediction ("NWP") model simulation produced by the wind energy consultancy firm 3TIER. While the data from the 3TIER study is useful, it is not sufficiently robust to build the scaling methodology around. Iberdrola is very familiar with NWP methods and knows that those methods contain particular problems with accuracy in forecasting the timing and strength of ramps.
> In addition, Bonneville has averaged the lag and lead time data provided by 3TIER. This will reduce the spread in ramp timing that we see in reality and thus will produce a picture of ramp reserve requirements that is not reflective of the actual need.

Froese *et al.*, WP-10-E-IR-01-CC01, at 22.

BPA understands the need to use "robust" datasets for forecasting purposes, but BPA is reluctant to deem the entire 3TIER dataset invalid on the basis of general claims about familiarity with models such as the one 3TIER used and the problems of such models. The only specific statement in this testimony addresses accuracy problems allegedly associated with models such as the one 3TIER used, but Iberdrola does not identify any particular accuracy problems, the magnitude of the problems, or the impact of those problems. *Id*. In fact, Iberdrola's testimony does not identify any flaws in the particular 3TIER data used in this case. In response to Iberdrola's general concerns, Staff states that it chose to use 3TIER because the company has multiple years of wind data, and the lead and lag information is the best available in the absence of a real-time wind monitoring system. McManus *et al.*, WP-10-E-BPA-42, at 5.

Iberdrola's other specific criticism is that BPA "averaged" the 3TIER data, allegedly reducing the spread in ramp timing. Froese *et al.*, WP-10-E-IR-01-CC01, at 22. Staff's rebuttal testimony demonstrates that this claim is incorrect. McManus *et al.*, WP-10-E-BPA-42, at 6. Staff states specifically that it did not average the 3TIER data. *Id*.

Iberdrola's testimony regarding the 3TIER data relies on assertions about general problems with models such as the one 3TIER used and inaccurately describes Staff's analysis. This evidence provides an insufficient basis to invalidate the 3TIER dataset.

For its claims that the 3TIER analysis was too subjective and that the use of the data was the result of misunderstandings between Staff and 3TIER, Iberdrola relies on Staff's cross-examination testimony (*see* Cross-Ex. Tr. at 83-95) and an exhibit with the 3TIER dataset itself (*see* WP-10-B-IR-03). Iberdrola argues that 3TIER lacked knowledge or misunderstood how Staff intended to use the data. Iberdrola Br., WP-10-B-IR-01, at 9. The cross-examination transcript contradicts that claim. Iberdrola asked Staff specifically whether 3TIER was informed that this data "was going to be used to determine your scaling in … future capacity" and Staff responded "yes." Cross Ex. Tr. at 83.

The emails between Staff and 3TIER demonstrate that Staff understood the nature of the data that it was requesting from 3TIER and what that data would represent, because Staff had requested and received the same type of data from 3TIER in the past. *See* WP-10-E-IR-03 (Response to Data Request No. IR-BPA-19). Staff accepted the 3TIER data as provided. Cross Ex. Tr. at 88. Although Staff acknowledges that they could not explain "all the ins and outs" of how 3TIER performed its analysis, this does not demonstrate misunderstanding or inadequacy of the data. Cross Ex. Tr. at 83.

Iberdrola also argues that 3TIER developed its dataset through a "visual inspection" method that is "highly subjective." Iberdrola Br., WP-10-B-IR-01, at 9. The only evidence in the record to evaluate the subjectivity of 3TIER's analysis is the spreadsheets provided by 3TIER and the communication between BPA and 3TIER regarding the data. That information demonstrates that BPA provided 3TIER location information for existing and planned wind projects, and that 3TIER used that data to determine time delays between sites. *See* WP-10-E-IR-03 (Response to Data Request No. IR-BPA-19). The spreadsheets provided by 3TIER state that the "delays are derived from windspeed changes exceeding 1m/s in 10 minutes, then, the data was statistically evaluated to try to find that same windramp event[.] When a ramp was identified at two sites, the time period between was recorded as the count and used to create a plot of a histogram." *Id*. The 3TIER data indicates that 3TIER evaluated the typical time delays between sites by examining the centroid of the histogram and also by visually inspecting the histogram "to find peaks indicating typical lags between projects." *Id.* The 3TIER spreadsheets state that the "visual inspection is more reliable" than the centroid evaluation, and Staff confirmed that they used the delays from the visual inspection method because 3TIER recommended using that data. *Id.*; Cross Ex. Tr. at 85, 86.

The information provided by 3TIER does not provide a basis to conclude that 3TIER's analysis is inherently subjective or unreliable. The site location and windspeed data that 3TIER used is objective information. 3TIER created a histogram using the time periods identified when the company identified a ramp at two sites, which appears to have been an objective analysis as well. 3TIER evaluated the typical time delays by determining the centroid of the histogram, which is objective analysis, and by visually inspecting the histogram to find peaks indicating typical lags. Although Iberdrola claims that the visual inspection method is a "highly subjective" method, this appears to be Iberdrola's interpretation of the term "visual inspection" rather than a fact supported by evidence in the record. Iberdrola Br., WP-10-B-IR-01, at 9. The 3TIER data provides no indication that the company subjectively evaluated the histograms to determine the peaks indicating typical lags. Furthermore, Iberdrola provides no evidence that suggests that 3TIER evaluated the histogram using subjective standards. Although 3TIER's visual inspection method may not have been a precise mathematical calculation, this particular inspection was performed by experts in wind energy forecasting from a firm that Iberdrola agrees is reputable. There is no reason to conclude that 3TIER's inspection of the data was so subjective as to be unreliable, especially given the objective standards that 3TIER appears to have applied to the other parts of the analysis.

Iberdrola points out that the 3TIER spreadsheets indicate that the visual inspection did not yield a "very clear indication of a most common ramp lead/lag time" in more than 80 percent of the cases. Iberdrola Br., WP-10-B-IR-01, at 9. Iberdrola accurately quotes from the 3TIER spreadsheet, and the record supports that more than 80 percent of the cells in the spreadsheet are not labeled as reflecting a "very clear indication of a most common ramp lead/lag time." WP-10-E-IR-03 (Response to Data Request No. IR-BPA-19). The implication from Iberdrola's brief is that the remaining data in the 3TIER spreadsheet is inadequate or unreliable, but nothing in the 3TIER information itself provides a basis for that conclusion. In fact, although approximately 20 percent of the values in the 3TIER data are labeled as very clear indication of the most common delay, additional cells are labeled as "[v]ery clear indication of multiple lag times" or "multiple lag times are apparent." *Id.* These notations indicate that 3TIER observed clear indications of lag times in more than the 20 percent of cases that Iberdrola cites. Moreover, to the extent that 3TIER reported clear indications of multiple lag times in the data, and Staff used those lag times in its analysis, that information would appear to introduce some of the additional diversity that Iberdrola claims the analysis lacks. The majority of cells in the 3TIER spreadsheet are not labeled at all, and the record includes no indication of 3TIER's perceptions of this data. In the absence of some evidence of belief by 3TIER that these unlabeled delays are inadequate or unreliable, there is no basis to deem the dataset invalid as a whole.

Iberdrola also suggests that using a model such as 3TIER's is inferior to using actual wind data. Iberdrola Br., WP-10-B-IR-01, at 8. According to Iberdrola, BPA admits in "response to Data Request IR-BPA-20 that actual (observed) lead and lag time data 'can be superior' to simulated data, but Bonneville made no attempt to obtain actual wind data from the wind industry in developing its scaling analysis." *Id*. (*quoting* Response to Data Request No. IR-BPA-20). The data response that Iberdrola cites is not in the record, and Iberdrola quotes from the response without the benefit of any context. Iberdrola's claims about any admission in this response are assigned no weight.

The record demonstrates that Iberdrola's claims are insufficiently supported to justify invalidating the 3TIER data. BPA is not persuaded that the 3TIER dataset is inadequate for use in the scaling analysis.

Decision

The 3TIER dataset is sufficiently reliable and adequate for use in the scaling analysis.

Issue 2

Whether the evidence in the record supports a conclusion that the scaling methodology contains systematic errors that overestimate the correlation between ramps at different facilities and have the effect of overstating the reserve requirement.

Parties' Positions

NWG and Iberdrola claim that Staff's scaling analysis is fundamentally flawed and contains systematic errors that overstate the extent to which the wind generators ramp up and down in a correlated manner. NWG Br., WP-10-B-NG-01, at 15-16; Iberdrola Br., WP-10-B-IR-01, at 9-11. Iberdrola claims that its evidence demonstrates that there is no clear pattern of lead and lag times between ramps at different facilities in the Balancing Authority Area and that the portfolio ramps are less numerous and less severe than Staff assumes. Iberdrola Br., WP-10-B-IR-01, at 10. Iberdrola suggests that Staff should have used "actual wind data obtained from the wind industry" to develop the scaling analysis. *Id*. at 8. Iberdrola argues that using "more accurate data" would reduce the reserve requirement. *Id*. at 10. Iberdrola states in its Brief on Exceptions that it was unable to replicate Staff's analysis because Staff was unable to provide the underlying data due to confidentiality concerns. Iberdrola Br. Ex., WP-10-R-IR-01, at 8.

NWG states that Staff presented data in a November 12, 2008 workshop that demonstrates a range of error between 5 percent and 20 percent in the scaling methodology. NWG Br., WP-10-B-NG-01, at 15. In addition, NWG alleges that the fact that approximately 800 MW of scaled wind in the Initial Proposal "was based on a single existing wind project" demonstrates the lack of diversity in the scaling analysis. *Id*. at 16. NWG argues in its Brief on Exceptions that BPA has not established that the results of the November 12 analysis are the product of error in the scaling methodology and that BPA's conclusions about Staff's testing of the scaling methodology are inconsistent. NWG Br. Ex., WP-10-R-NG-01, at 6-8.

Cowlitz suggests that BPA should develop more sophisticated tools to model wind fleet behavior and to improve the scaling methodology. Cowlitz Br., WP-10-B-CO-01, at 8-9. In testimony, Cowlitz suggests that BPA adjust the following reserve forecast by the error in the scaling methodology. Skeahan *et al.*, WP-10-E-CO-01, at 7.

PPC *et al.* state that Iberdrola and NWG have not demonstrated that "BPA's methodology systematically overestimates wind ramping," and they specifically question NWG's characterization of Staff's analysis to validate the scaling methodology. PPC *et al.* Br., WP-10-B-JP11-01, at 32.

BPA Staff's Position

The scaling methodology does not contain fundamental flaws that overestimate the wind ramps in the Balancing Authority Area, and the scaling analysis as a whole does not result in a forecast of the reserve requirement that exceeds actual needs. McManus *et al.*, WP-10-E-BPA-42, at 12. Staff makes deliberate efforts to introduce some of the "diversity" between sites. McManus *et al.*, WP-10-E-BPA-23, at 13. In addition, Staff provides analysis to demonstrate high correlation in the average output of all wind facilities in the Balancing Authority Area on an hourly basis. McManus *et al.*, WP-10-E-BPA-42, at 6.

Evaluation of Positions

No party seems to dispute the general assumption underlying the scaling analysis that weather patterns in the Balancing Authority Area tend to move from west to east. *See, e.g.*, Dragoon, WP-10-E-NG-01, at 9. It is the degree of variation within that general pattern, and the alleged failure of the scaling analysis to account for that variation, that seem to be of concern. Only Iberdrola appears to suggest that the scaling analysis should rely solely on actual wind generation data rather than using model-based data. Iberdrola Br., WP-10-B-IR-01, at 8. Even NWG, which alleges that the scaling analysis includes material error, concedes that "there is no perfect solution to developing wind generation estimates for projects that have yet to be constructed, and for which there may not be available on-site data." Dragoon, WP-10-E-NG-01, at 10. NWG states that "approximate methods in [its] view are both acceptable and unavoidable." *Id.* Cowlitz supports improvements to the scaling methodology through using mesoscale modeling but recognizes that implementing improvements in this rate proceeding is impractical. Cowlitz Br., WP-10-B-CO-01, at 8-9; Skeahan *et al.*, WP-10-E-CO-01, at 7.

NWG is correct that using approximate methods and models is acceptable in this rate proceeding. There is no real-time wind monitoring system currently in place in the BPA Balancing Authority Area to provide on-site data for wind facilities that do not yet exist. McManus *et al.*, WP-10-E-BPA-42, at 5. Staff and PPC *et al.* point out that Staff has used the best data available. *Id.*; PPC *et al.* Br., WP-10-B-JP11-01, at 33.

The record demonstrates that Staff took specific steps to help ensure that the scaling analysis reflects some of the "diversity" of conditions in the Balancing Authority Area. First, Staff uses data for multiple existing projects to scale the output of a planned project where possible. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 12. According to Staff, by "using more than one existing wind facility, we are able to ensure that some of the diversity in wind output was reflected in the future wind facilities." McManus *et al.*, WP-10-E-BPA-23, at 13. Although NWG points out that approximately 800 MW of planned wind facilities are scaled in the Initial Proposal using only one existing facility, the record demonstrates that Staff scaled in approximately 2,500 MW using at least two and in some cases three existing facilities. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 27-30. In addition, the record demonstrates that Staff adjusted the 3TIER data based on actual observations in instances when the 3TIER data indicated that certain facilities ramped up or down exactly simultaneously. *Id*. at 12. Staff testifies that its observations of actual conditions in the Balancing Authority Area demonstrate that simultaneous ramps between specific facilities were rare. *Id*.

The criticisms in Iberdrola's brief do not seem to provide a real alternative for estimating the output of a wind fleet that does not yet exist. Iberdrola criticizes the scaling methodology as relying on simplistic assumptions that do not reflect the complex conditions throughout the Balancing Authority Area, and Iberdrola suggests that Staff should have sought out actual data from the wind fleet. Iberdrola Br., WP-10-B-IR-01, at 9-10. At the same time, however, Iberdrola condemns Staff's adjustment of the 3TIER data based on actual observations as "introducing further flaws into the scaling methodology." *Id*. at 9. Had Staff not adjusted the 3TIER data to remove the simultaneous ramps, the reserve requirement likely would have been higher. McManus *et al.*, WP-10-E-BPA-42, at 7; Cross Ex Tr. at 143-144.

Iberdrola's chief complaint seems to be that Staff's assumptions and adjustments to the data do not match up with the results of Iberdrola's analysis of its actual data. Iberdrola Br., WP-10-B-IR-01, at 10. Iberdrola maintains that its analysis demonstrates that there is no pattern of leads and lags amongst its facilities. Staff's rebuttal testimony acknowledges the more limited correlation in the output of certain facilities in the Iberdrola analysis, but that analysis does not provide a basis to conclude that the general assumptions about the west to east weather trend or the methodologies in the scaling analysis are fundamentally flawed. McManus *et al.*, WP-10-E-BPA-42, at 6. Staff also provided correlation analysis of the actual output of the wind fleet in March 2009. *Id*. This analysis reflects high correlation amongst the output of all wind facilities in the Balancing Authority Area on an hourly basis, which tends to support the assumption that there are identifiable patterns to the wind fleet ramps and generation. *Id*.

Iberdrola's analysis of data from its facilities identifies 22 "major" events in which the facilities ramped up in 2008. Froese *et al.*, WP-10-E-IR-01-CC01, at 24. As Staff testifies, this alone demonstrates a significant number of times that the entire Iberdrola wind portfolio experienced a major ramp and further supports the assumption about correlation between the ramps of wind facilities in the Balancing Authority Area. McManus *et al.*, WP-10-E-BPA-42, at 8. Furthermore, the maps included with the 3TIER analysis demonstrate that the vast majority of wind facilities that are expected to be online during the rate period are clustered in the area around the Columbia Gorge. *See* WP-10-E-IR-03 (Response to Data Request No. IR-BPA-19). The fact that many of the planned facilities are located in the same general area of many existing facilities, including some of those included in Iberdrola's analysis, suggests that the diversity of the future wind fleet will not be as significant as Iberdrola predicts. McManus *et al.*, WP-10-E-BPA-42, at 8. Finally, the average lead and lag values in Iberdrola's analysis reflect a general trend of facilities in the western part of the Balancing Authority Area ramping prior to the facilities in the eastern part of the Balancing Authority Area. Froese *et al.*, WP-10-E-IR-01-CC01, at 44, Attachment B. This is consistent with the general assumptions underlying the scaling methodology.

Iberdrola states in its Brief on Exceptions that it was unable to replicate BPA's scaling analysis, because BPA was unable to provide the underlying data due to confidentiality concerns. Iberdrola Br. Ex., WP-10-R-IR-01, at 8. Iberdrola has not included information in the record to demonstrate that it was unable to obtain certain information, and the record reflects no efforts by Iberdrola to compel production of any information that was withheld. Nevertheless, Iberdrola's claim deserves a response. BPA treats certain wind generation information as confidential at the request of wind generators. If wind generators desire public disclosure of such information in the future, BPA encourages discussion of those issues with Staff.

NWG claims that analysis that Staff presented in pre-rate case workshops demonstrates the systematic error in the scaling methodology. NWG Br., WP-10-B-NG-01, at 15. Staff presented two sets of analysis performed to validate the scaling analysis. First, Staff presented information at a September 17, 2008 workshop that compared actual output of four facilities to the estimated output under the scaling methodology. Second, Staff presented analysis on November 12, 2008, comparing the reserve requirement that resulted from using the actual output compared to the estimated output. *Id.* at 10. This comparison reflected a higher *dec* reserve requirement using the estimated output than using the actual output. *Id.*

NWG maintains that Staff's November 12 analysis comparing the overall reserve requirement using the actual output as opposed to scaled output demonstrates the error in the scaling methodology. NWG Br., WP-10-B-NG-01, at 15. NWG's testimony and Initial Brief do not acknowledge Staff's September 17 analysis or Staff's explanation for the discrepancy in the November 12 analysis. *See* McManus *et al.*, WP-10-E-BPA-42, at 9 ("NWG testified about only part of the analysis that BPA performed, and it did not point out the specifics regarding the facilities that BPA studied."). NWG acknowledges Staff's September 17 analysis and Staff's explanations of the results of the November 12 analysis for the first time in its Brief on Exceptions. NWG Br. Ex., WP-10-R-NG-01, at 7.

Staff explained in rebuttal testimony that the generators used in the November 12 analysis were still in a startup phase, and actual generation did not reach peak capacity. McManus *et al.*, WP-10-E-BPA-42, at 10. Staff explained that the *dec*s in the forecast reserve requirement based on the scaled figures are understandably higher than those using the actual data in this situation, because the generation peaks using actual data did not reflect the facility's entire capacity that was used for the scaling analysis. *Id.*

BPA believes that Staff has provided a credible explanation for why the results of the November 12 analysis do not demonstrate error in the scaling methodology, and BPA accepts Staff's explanation rather than the explanation that NWG provides. NWG argues that the record lacks substantial evidence to conclude that Staff's explanation is any more "credible" than NWG's belief that the scaling methodology is flawed. NWG Br. Ex., WP-10-R-NG-01, at 7. BPA disagrees. As described above, NWG's testimony and its Initial Brief fail to acknowledge that Staff performed two separate analyses to verify the accuracy of the scaling methodology. Staff's September 17 analysis shows that the trends in the facilities' actual generation were fairly consistent with the trend of the estimated output using the scaling analysis, indicating that the scaling analysis was fairly accurate. McManus *et al.*, WP-10-E-BPA-42, at 9-10. When Staff compared the actual generation against scaled generation, the ramps and peaks lined up, the standard deviations of the actual and estimated output were close, and the correlation was very high. *Id*. This indicates that the scaling methodology is accurate. *Id*. at 12. BPA assigns less weight to NWG's claims that Staff's analysis demonstrates error in the scaling methodology because NWG's explanation accounts for only part of Staff's analysis.

BPA also believes that Staff's explanation of its efforts to test the scaling methodology deserve more weight than NWG's claims about analysis that NWG did not perform. NWG's emphasis on certain results from one part of Staff's analysis only highlights that NWG's testimony includes no independent analysis to support NWG's claims about error in the scaling methodology. NWG's Brief on Exceptions states that NWG's responses to BPA data requests include analysis demonstrating the alleged error in the methodology. NWG Br. Ex., WP-10-R-NG-01, at 7. These responses are not in the record, and the only "analysis" referred to in the responses that NWG cites is the Iberdrola analysis discussed above. That analysis does not provide a basis to conclude that the scaling methodology is flawed, for the reasons described previously.

Furthermore, as PPC *et al.* note, Staff's analysis reflected both overestimations and underestimations of the scaled values for different components and did not show consistent bias in one direction. Baker *et al.*, WP-10-E-JP6-03, at 7. In other words, Staff's November 12 analysis shows that the reserve requirements using the scaled data were lower than the requirements using actual generation for certain reserve components. *See* Baker *et al.*, WP-10-E-JP6-04, Attachments 2 and 3. NWG's allegations that the analysis shows errors of 5 percent to over 20 percent are based on the results for particular components of the wind reserves in that analysis, and that range does not even appear to be a comparison of like components. *See id*.; Dragoon, WP-10-E-NG-01, at 8; NWG Br., WP-10-B-NG-01, at 16. The 5 percent end of NWG's range is based on the total *inc* reserves for wind, but the allegations of error over 20 percent are based on the results for the *dec* reserve for the imbalance component for wind. Baker *et al.*, WP-10-E-JP6-03, at 8; Baker *et al.*, WP-10-E-JP6-04, Attachment 3. The difference in the total *dec* reserves for wind under Staff's analysis is less than 1 percent. Baker *et al.*, WP-10-E-JP6-04, Attachment 3. NWG's claims about Staff's November 12 analysis do not support a finding that the scaling analysis is inherently flawed or includes a systematic error.

With respect to the results of Staff's September 17 analysis, NWG calls it a "subjective visual inspection" and argues that BPA's reliance on the September 17 analysis to disagree with NWG's claims about the November 12 analysis is inconsistent with BPA's conclusions that the data "is not reliable enough" to support NWG's claims about systematic error. NWG Br. Ex., WP-10-R-NG-01, at 7. First, BPA has never stated that either the September 17 or November 12 analysis is unreliable. Staff has explained the reasons for the difference in the results for *decs* in the November 12 analysis in response to NWG's repeated claims that the analysis conclusively demonstrates systematic error in the scaling methodology, and BPA has accepted that explanation. McManus *et al.*, WP-10-E-BPA-42, at 9-10. Second, NWG's claim about a "subjective visual inspection" has no support in the record. Given that NWG's Brief on Exceptions is the first time that NWG has acknowledged the September 17 analysis, NWG's testimony does not address this issue, and no other party has had an opportunity to address this claim, BPA assigns no weight to NWG's claim about subjectivity under these circumstances.

NWG's argument about the meaning of Staff's analysis does not support a finding that the scaling analysis is inherently flawed or includes a systematic error.

Decision

The evidence in the record does not support a conclusion that the scaling analysis contains systematic errors that overstate the correlation of ramps between different facilities and have the effect of overstating the reserve requirement. This is an area that will benefit from further analysis in future rate cases as the data evolves.

Issue 3

Whether BPA should use different assumptions or data in the scaling methodology or adjust the reserve forecast downward in response to allegations of systematic errors in the methodology that have the effect of overstating the reserve requirement.

Parties' Positions

Several parties suggest that BPA should use different assumptions or data in the scaling methodology or reduce the overall reserve requirement to reflect systematic errors in the methodology. Cowlitz suggests that BPA improve the scaling methodology by using mesoscale forecasting techniques. Cowlitz Br., WP-10-B-CO-01, at 8-9. Iberdrola suggests using a "more robust method" or reducing the reserve requirement proportionally with systematic errors in the methodology. Iberdrola Br., WP-10-B-IR-01, at 11; Iberdrola Br. Ex., WP-10-R-IR-01, at 8.

NWG points out that its testimony identified several alternatives that it alleges would more accurately represent the behavior of new wind generators. NWG Br., WP-10-B-NG-01, at 16. NWG states that although it may be too late in this proceeding for BPA to adopt a more accurate methodology, it is not too late for BPA to reduce its reserve requirements to reflect the systematic undercounting of diversity among wind projects introduced by the scaling methodology. *Id*. NWG claims that BPA's estimate of the error is between 5 percent and 20 percent and suggests reducing the reserve requirement for wind by 12.5 percent to reflect the error. *Id*. NWG argues in its Brief on Exceptions that BPA should reduce the reserve forecast by 12.5 percent until BPA establishes the reasons for the discrepancy in the results of Staff's November 12 analysis. NWG Br. Ex., WP-10-R-NG-01, at 8.

PPC *et al.* state that the scaling methodology and the data sets used are the best available at this time. PPC *et al.* Br., WP-10-B-JP11-01, at 33. PPC *et al.* state that the various alternatives that have been suggested have not been provided and are not practical to implement because they would not be tested in the rate case process. Baker *et al.*, WP-10-E-JP6-03, at 11-12. PPC *et al.* state that the 5 to 20 percent error identified by NWG does not constitute a valid range. *Id.* at 8.

BPA Staff's Position

Using different data or reducing the reserve forecast is unjustified, because the scaling methodology does not contain fundamental flaws that result in a forecast of the reserve requirement that exceeds actual needs. McManus *et al.*, WP-10-E-BPA-42, at 11-12. Although parties suggest using alternative data, no party has included that alternative data in the record in this proceeding or demonstrated that using alternative data would more accurately forecast the reserve requirement. *Id.* at 11.

Evaluation of Positions

Parties propose multiple alternatives to the data used in the scaling methodology, but the record does not include the alternative data, any verification of the alternative data, or any evidence that using alternative data would result in a more accurate reserve forecast. McManus *et al.*, WP-10-E-BPA-42, at 11; Baker *et al.*, WP-10-E-JP6-03, at 11-12. As Staff points out, modifying the methodology or using alternative data is just as likely to increase the reserve forecast as it is to decrease the forecast. McManus *et al.*, WP-10-E-BPA-42, at 11. Even if BPA decided to use alternative data or methodologies, the parties offer conflicting suggestions about what would improve the scaling analysis. Cowlitz suggests that using mesoscale forecasting techniques is "critical" to improving the scaling methodology, but Iberdrola considers the mesoscale models inadequate. Cowlitz Br., WP-10-B-CO-01, at 8-9; Froese *et al.*, WP-10-E-IR-01-CC01, at 22.

NWG suggested in testimony that BPA reduce the reserve forecast to reflect the error NWG identified in the scaling methodology, but NWG proposed a specific reduction of 12.5 percent to the wind reserve requirement for the first time in its Initial Brief. Dragoon, WP-10-E-NG-01, at 11; NWG Br., WP-10-B-NG-01, at 16. NWG's Brief on Exceptions explains that the 12.5 percent adjustment is the mid-point of NWG's range of alleged error between 5 percent and 20 percent. NWG Br. Ex., WP-10-R-NG-01, at 8. This does not appear to be a valid range of comparable values, for the reason described in response to the previous issues. *See* Baker *et al.*, WP-10-E-JP6-03, at 8. NWG's claims that Staff's analysis to validate the scaling methodology demonstrates the error are unpersuasive for the reasons described in response to previous issues as well. The *dec* reserve requirement determined from the scaled generation exceeded the reserve requirement using the actual generation because the four facilities in the analysis were not yet generating at full capacity. McManus *et al.*, WP-10-E-BPA-42, at 10. Furthermore, the comparison of the actual generation and scaled generation demonstrates that the scaling analysis is fairly accurate. *Id.* at 12. A reduction to the wind reserve requirement to reflect error in the scaling methodology is inappropriate in these circumstances.

NWG takes issue with the description of Staff's position that the scaling methodology does not contain "fundamental flaws" that result in overstating the reserve requirement. NWG Br. Ex., WP-10-R-NG-01, at 8. NWG argues that BPA should adjust for any known errors in the scaling methodology, even if they are not "fundamental flaws." *Id.* NWG and Iberdrola have used a variety of adjectives to describe the alleged errors in the scaling methodology. *Id.* at 8 ("systematic errors"); NWG Br., WP-10-B-NG-01, at 15 ("systemic errors"); Iberdrola Br., WP-10-B-IR-01, at 7, 9 ("fundamentally flawed" and "severely inadequate"). BPA's statement of Staff's position and the discussion of the alleged flaws in the methodology reflect the descriptions used by NWG and Iberdrola. BPA is not declining to adjust the reserve requirement or the assumptions in the scaling methodology because the alleged errors do not rise to the level of fundamental flaws. BPA is declining to adopt those adjustments because the evidence in the record does not support a conclusion that the scaling analysis includes errors that result in overstating the reserve requirement for the rate period.

Decision

BPA will not use different assumptions or data in the scaling methodology or adjust the reserve forecast downward given that the evidence in the record does not support a conclusion that the scaling analysis contains systematic errors.

13.3.2.3 Scheduling Accuracy Assumption

The reserve forecast methodology relies on an assumption about the scheduling accuracy of the wind fleet during the rate period. Staff analyzed the wind fleet's current scheduling accuracy using standard statistics and measured that accuracy in terms of persistence models. The reserve forecast in the Initial Proposal assumes scheduling accuracy equivalent to a two-hour persistence model. Staff's analysis in rebuttal testimony indicates that accuracy has improved to a 60-minute persistence level.

The scheduling accuracy assumption also relates to the operational and reliability requirements in DSO 216. BPA will order feathering of wind generation or curtailment of transmission schedules under DSO 216 when BPA has deployed 90 percent of balancing reserves. BPA intends to hold an amount of balancing reserves consistent with the rate case reserve forecast, and the forecast decreases with assumptions of more accurate scheduling by the wind fleet. As a result, assuming more accurate scheduling will reduce the reserve forecast and the Wind Balancing Service rate, but also will result in BPA holding and managing a smaller amount of balancing reserves for purposes of DSO 216. Holding less balancing reserves likely will result in more feathering and curtailment orders under DSO 216.

Issue 1

Whether the record demonstrates that the current scheduling accuracy of wind generators has improved to an accuracy equivalent to a 30-minute, 45-minute, or 60-minute persistence model.

Parties' Positions

PPC *et al.* state that the Staff analysis presented in rebuttal testimony is the best evidence to demonstrate improvements in scheduling accuracy. PPC *et al.* Br., WP-10-B-JP11-01, at 33. PPC *et al.* state that this evidence demonstrates that current wind fleet scheduling accuracy has improved to be equivalent to a 60-minute persistence model. *Id.* at 33-34. PPC *et al.* also state that the Iberdrola and NWG claims that current scheduling accuracy is more accurate than 60-minute persistence are based on insufficient data and inadequate analysis. *Id.* at 33.

Iberdrola claims that its analysis of the scheduling accuracy of its facilities over a three-week period in March 2009 demonstrates that its scheduling accuracy already has improved to be equivalent to between a 30-minute and 45-minute persistence model. Froese *et al.*, WP-10-E-IR-01-CC01, at 30.

NWG claims that accuracy improved to between 45 and 50 minutes for the period January-March 2009, and to between 35 and 40 minutes during a more recent week. Dragoon, WP-10-E-NG-04, at 5.

According to the OPUC, the record demonstrates that some wind generators are capable of achieving accuracy equal to 30-minute persistence and that the remainder are capable of accuracy equal to 45-minute persistence. OPUC Br., WP-10-B-PU-01, at 13.

Cowlitz points out that Iberdrola's scheduling accuracy falls between the 45-minute and 30-minute persistence measures. Cowlitz Br., WP-10-B-CO-01, at 10.

BPA Staff's Position

BPA Staff's analysis demonstrates that the wind fleet achieved scheduling accuracy equal to 60-minute persistence from August 2008 to March 2009. McManus *et al.*, WP-10-E-BPA-42, at 13.

Evaluation of Positions

The evidence in the record demonstrates that the scheduling accuracy of the wind fleet has improved significantly from August 2008 when Staff analyzed scheduling accuracy for the Initial Proposal. Staff's analysis in the Initial Proposal indicates that scheduling accuracy for the period from August 2007 to August 2008 is equivalent to a two-hour persistence model. McManus *et al.*, WP-10-E-BPA-23, at 16-18. Staff's rebuttal testimony demonstrates that current scheduling accuracy for the wind fleet as a whole is equivalent to a 60-minute persistence model. McManus *et al.*, WP-10-E-BPA-42, at 13-15. Staff's rebuttal analysis is based on approximately seven months of data for the wind fleet, from August 2008 to March 2009. *Id*. BPA agrees with PPC *et al.* that Staff's conclusion is based on a sufficiently large data set covering a long enough period to be credible and provides an adequate basis to conclude that the improvement reflects a sustained trend. PPC *et al.* Br., WP-10-B-JP11-01, at 33. A noticeable improvement in scheduling accuracy appears to have started in September 2008 and has persisted since that time. McManus *et al.*, WP-10-E-BPA-42, at 13.

Iberdrola's scheduling accuracy analysis demonstrates that the company's facilities have achieved accuracy between 45-minute and 30-minute persistence levels at times, but Iberdrola's analysis provides an insufficient basis to conclude that the entire wind fleet has achieved that level of accuracy on a sustained basis. *Id*. at 15. NWG's claims and evidence are similar. The wind fleet as a whole may be able to achieve scheduling accuracy better than 60-minute persistence at certain times, but the evidence on the record provides an inadequate basis to conclude that the wind fleet as a whole currently is scheduling more accurately than a 60-minute persistence measure.

Decision

The evidence in the record demonstrates that the current scheduling accuracy of the wind fleet as a whole is equivalent to a 60-minute persistence model, although certain facilities have scheduled more accurately than this measure at times.

Issue 2

Whether there is a reasonable basis to conclude that wind scheduling accuracy can be expected to improve beyond the current scheduling accuracy.

Parties' Positions

PPC *et al.* maintain that BPA cannot reasonably adopt a scheduling accuracy assumption based on the expectation that scheduling can continue to improve during the rate period. PPC *et al.* Br., WP-10-B-JP11-01, at 33. According to these parties, the investments required to schedule more accurately present barriers to further improvement, and the record does not support the opinion that Generation Imbalance charges and the Persistent Deviation Penalty will motivate such improvement. *Id*. at 34-35. PPC *et al.* argue in their Brief on Exceptions that simply providing information to wind generators will not help to improve scheduling accuracy unless the generators make use of such information and have the training and expertise to do so. PPC *et al*. Br. Ex., WP-10-R-JP12-01, at 15-16.

Cowlitz states that the WIT operational and reliability requirements and the financial incentives created by the Persistent Deviation Penalty and Generation Imbalance charges provide a sufficient basis to expect scheduling accuracy to improve. Cowlitz Br., WP-10-B-CO-01, at 9.

LADWP states that accuracy can be expected to improve, because the analysis of current scheduling accuracy does not take into account improvements that will result from BPA infrastructure improvements. LADWP Br., WP-10-B-LA-01, at 18.

NWG maintains that accuracy will improve as a result of a variety of factors. NWG notes that the industry has moved swiftly to improve its accuracy in response to the BPA awareness campaign and that the wind fleet has achieved accuracy equivalent to 60-minute persistence in the absence of DSO 216. NWG Br., WP-10-B-NG-01, at 12-13.

Iberdrola argues that scheduling accuracy should continue to improve because of BPA initiatives and infrastructure improvements, and Iberdrola identifies specific BPA efforts to facilitate more accurate scheduling. Iberdrola Br., WP-10-B-IR-01, at 11-12, 14-15. Iberdrola also describes significant steps that it is taking to improve scheduling accuracy, including hiring five meteorologists and beginning 24/7 shift rotations for wind forecasters as of June 1, 2009. *Id*. at 13. Iberdrola points out that its resources currently constitute slightly less than half of the wind in BPA's Balancing Authority Area, and Iberdrola reasons that its scheduling accuracy improvements will materially impact wind fleet accuracy as a whole. *Id*. at 12.

BPA Staff's Position

Staff's analysis demonstrates sustained improvement in wind fleet scheduling accuracy since BPA first made wind generators aware of the accuracy that BPA observed prior to August 2008. McManus *et al.*, WP-10-E-BPA-42, at 13-14. Infrastructure investments and initiatives that BPA is undertaking specifically to improve scheduling accuracy should facilitate more accurate scheduling by the wind fleet. In addition, the WIT reliability and operational requirements, Generation Imbalance charges, and the Persistent Deviation Penalty will provide incentives to schedule accurately. Mainzer *et al.*, WP-10-E-BPA-41, at 34, 37.

Evaluation of Positions

The record demonstrates that the wind fleet has increased its scheduling accuracy significantly since August 2008, improving from a two-hour persistence level to a 60-minute level without BPA implementing new penalty rates or operating protocols. McManus *et al.*, WP-10-E-BPA-42, at 13-15. A noticeable improvement occurred in September 2008, following the WIT's publication of data to demonstrate the scheduling accuracy at the time and the WIT's efforts to raise awareness about the impact of inaccurate scheduling. *Id.* at 13. The improvement also coincides with the time period in which BPA began to quantify the impact of inaccurate scheduling on the wind integration rate. *See* Froese *et al.*, WP-10-E-IR-01-CC01, at 27. The significant improvements in a relatively short period of time indicate that awareness of inaccurate scheduling and its potential ramifications can help motivate better scheduling without implementing new rates or operating requirements. This strongly suggests that scheduling accuracy will continue to improve in the rate period when new rates and requirements will be in effect.

PPC *et al.* assert a variety of reasons why BPA cannot reasonably adopt a scheduling accuracy assumption based on evidence regarding the incentives and investments to facilitate improvement. PPC *et al.* Br., WP-10-B-JP11-01, at 34-35. PPC *et al.* state that Generation Imbalance charges and the Persistent Deviation Penalty create insufficient incentive for wind generators to continue to improve scheduling. *Id.* PPC *et al.* note that Staff is not proposing to modify the Generation Imbalance charge, and the potential effectiveness of the Persistent Deviation Penalty cannot be assessed. *Id.* at 35. They also maintain that the operational and reliability requirements in DSO 216 will not materially increase scheduling accuracy. *Id.* Finally, PPC *et al.* emphasize the cost barriers to investing in equipment to improve accuracy. *Id.* at 34. In its Brief on Exceptions, PPC *et al.* argue that the record does not support an assumption of further dramatic improvements in scheduling accuracy or provide a basis for quantifying the improvement relative to any particular persistence measurements. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 15.

PPC *et al.* focus on factors that create incentives for the wind fleet to improve scheduling accuracy and are unconvinced that the incentives will have the intended effect. BPA disagrees with this perspective, as explained in detail below. More importantly, however, focus on the penalties for poor scheduling alone does not account for affirmative efforts that BPA and wind generators are undertaking to facilitate scheduling improvements during the rate period. *See* WP-10-E-IR-04 (Response to Data Request No. IR-BPA-9); Iberdrola Br., WP-10-B-IR-01, at 14. These efforts will provide infrastructure and information that the wind fleet can utilize to schedule more accurately rather than establishing penalties or operating limitations if the fleet does not. *See* Iberdrola Br., WP-10-B-IR-01, at 14. Given the financial and operational incentives for the wind fleet to schedule accurately, it is unreasonable to assume that even schedulers that have been unconcerned about accuracy in the past would not take advantage of information that will help improve their efforts at little or no cost.

The record demonstrates the investments that BPA and other parties are making to integrate wind generation into the Balancing Authority Area and to facilitate more accurate scheduling. Mainzer *et al.*, WP-10-E-BPA-22, at 23. BPA is installing 16 additional wind monitoring sites in the Balancing Authority Area by the end of FY 2009. These sites will generate five-minute wind data that will be available to all customers for scheduling purposes. Iberdrola Br., WP-10-B-IR-01, at 14. Iberdrola states that current infrastructure provides only four well-maintained and quality-controlled observation sites across the Columbia Gorge and that these sites report hourly data. *Id*. According to Iberdrola, the locations of the current sites are not ideal, and the reports are provided at the top of the hour, which limits the usefulness of the information. *Id*.; Froese *et al.*, WP-10-E-IR-01-CC01, at 29. The additional observation stations should provide more data in a more useful manner, and there is no reason that wind generators should not take advantage of that information to prepare accurate schedules. *See* Iberdrola Br., WP-10-B-IR-01, at 14.

Iberdrola identifies a number of efforts it has implemented to improve its scheduling. *Id*. at 12-13. Iberdrola has hired five meteorologists to create a real-time forecasting function that will provide hourly project-specific generation 24 hours a day and seven days a week. *Id*. at 13; Froese *et al.*, WP-10-E-IR-01-CC01, at 28. Iberdrola points out that its resources comprise a little less than half of the wind fleet, and improvements in its scheduling accuracy should materially affect the accuracy of the fleet as a whole. Iberdrola Br., WP-10-B-IR-01, at 12. BPA agrees that the evidence of efforts such as Iberdrola's help provide a reasonable basis to expect scheduling accuracy to continue to improve during the rate period.

The claims that BPA cannot reasonably expect more accurate scheduling during the rate period are unconvincing when evaluated against the backdrop of the relatively rapid improvement that the wind fleet has demonstrated already and the deliberate efforts of BPA and others to facilitate additional improvement. Although PPC *et al.* maintain that Generation Imbalance charges and the Persistent Deviation Penalty provide insufficient incentive to continue to improve accuracy, the record includes extensive evidence from the wind community of their desire and incentive to avoid those charges. Froese *et al.*, WP-10-E-IR-01-CC01, at 12-14; Skidmore, Oral Tr. at 64; Murphy, Oral Tr. at 111. Staff agrees that the charges provide an incentive to schedule accurately. Mainzer *et al.*, WP-10-E-BPA-41, at 37.

PPC *et al.* also emphasize that the investments required to schedule more accurately create a barrier to further improvement. PPC *et al.* Br., WP-10-B-JP11-01, at 35. BPA is making infrastructure investments that will provide the entire wind fleet with information to use to schedule more accurately. That information, and other forecast data that results from BPA's other efforts to enhance scheduling, will be available to wind generators without them making any additional investment.

PPC *et al.* also argue that simply supplying information to wind generators is unlikely to improve scheduling unless schedulers can account for the information and have the training to know how to apply it, which requires investment in staff and training. PPC *et al*. Br. Ex., WP-10-R-JP12-01, at 15. BPA acknowledges that some effort on the part of wind generators will be necessary to continue to improve scheduling accuracy, but the record includes no basis to conclude that the "barriers" are so significant or costly that improvements will not continue. In fact, the evidence in the record indicates that wind generators improved accuracy significantly simply as a result of BPA providing data regarding the degree of accuracy that BPA observed prior to September 2008 and quantifying the impact of inaccurate scheduling on the Wind

Balancing Service rate. *See* McManus *et al.*, WP-10-E-BPA-42, at 13; Froese *et al.*, WP-10-E-IR-CC01, at 27. Moreover, NWG specifically states in its Brief on Exceptions that its members will continue the commitment to scheduling accuracy. NWG Br. Ex., WP-10-R-NG-01, at 9.

Finally, Iberdrola points out that wind generators can make relatively modest investments in measures other than equipment to improve accuracy and that some wind generators may choose to contract with others rather than investing in their own new equipment or personnel. Iberdrola Br., WP-10-B-IR-01, at 13-14. The alleged barriers to scheduling accurately provide no basis to conclude that the improvements in accuracy will not continue during the rate period.

Staff points out that the reliability and operation protocols that will be in effect during the rate period are among the factors that should provide incentive for the wind fleet to continue to improve scheduling accuracy. Mainzer *et al.*, WP-10-E-BPA-41, at 34. Iberdrola and NWG have proposed that BPA develop a reserve forecast based on an assumption that scheduling accuracy will be equivalent to a 30-minute persistence model and then manage reserves through operational and reliability requirements in DSO 216. Hall, Oral Tr. at 49; Skidmore, Oral Tr. at 62. This proposal creates additional incentive to schedule accurately, because wind generators will bear the risk of featherings or curtailments if actual scheduling is poor. PPC *et al.* point out that only one wind generator has provided specific evidence of its willingness and actions to improve accuracy; however, the DSO 216 requirements will apply to all wind generators during the rate period and will provide more incentive to schedule accurately to avoid feathering and curtailment. PPC *et al*. Br. Ex., WP-10-R-JP12-01, at 16, n. 32.

The record demonstrates that the wind fleet significantly improved its scheduling accuracy in a short period of time without the implementation of new rates, operating protocols, or other incentives, and BPA and other parties are currently taking affirmative efforts to ensure that the improvements continue. Based on all of these factors, wind fleet scheduling accuracy can reasonably be expected to improve during the rate period.

Decision

The evidence in the record provides a reasonable basis for BPA to conclude that wind scheduling accuracy can be expected to improve beyond the current scheduling accuracy.

Issue 3

Whether requirements customers bear all the financial risk if BPA underestimates the wind reserves needed by adopting an assumption that the wind fleet will be scheduling more accurately than a 60-minute persistence model during the rate period.

Parties' Positions

PPC *et al.* state that adopting an assumption that wind generators will schedule more accurately than 60-minute persistence based on the expectation that the wind fleet accuracy will continue to improve shifts significant risks to BPA's requirements customers and is contrary to cost causation principles. PPC *et al.* Br., WP-10-B-JP11-01, at 36; PPC *et al*. Br. Ex., WP-10-R-JP12-01, at 16-18. According to PPC *et al.*, BPA has carried more reserves than assumed for the

WI-09 rate, and loads are bearing the financial consequences. PPC *et al.* Br., WP-10-B-JP11-01, at 36. PPC *et al.* also assert that implementation of DSO 216 will not necessarily protect requirements customers, because nothing prevents BPA from holding reserves in excess of the forecast and BPA may face pressure to hold reserves in excess of the forecast. *Id.* at 36-37; PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 17. Snohomish and NRU join the arguments of PPC *et al.* Snohomish Br. Ex., WP-10-R-SN-01, at 2; NRU Br. Ex., WP-10-R-NR-01, at 9.

BPA Staff's Position

The reserves held for wind need to be reasonably related to the actual, demonstrated scheduling accuracy of the fleet even with the operating protocols in DSO 216. Mainzer *et al.*, WP-10-E-BPA-41, at 32. Successful implementation of DSO 216 should eliminate use of reserves in excess of the total reserves available, however, and BPA has no motivation to set aside additional reserves in any event. *Id.* at 34.

Evaluation of Positions

PPC *et al.* raise an issue that parties associate with many rate case assumptions—who bears the risk if actual results during the rate period differ from the assumptions? PPC *et al.* maintain that requirements customers bear all the financial risk if the reserve forecast assumes that the wind fleet will schedule more accurately than a 60-minute persistence measure. PPC *et al.* Br., WP-10-B-JP11-01, at 36. BPA disagrees. The operating requirements in DSO 216 specifically place the risk of that scenario on wind generators and the loads they serve. Mainzer *et al.*, WP-10-E-BPA-41, at 32.

If the wind fleet is unable to achieve the level of scheduling accuracy that BPA assumes for the reserve forecast, the operational and reliability protocols in DSO 216 likely will trigger more frequently. *Id.* Iberdrola and NWG both acknowledge that a reserve forecast based on an assumption that the wind fleet would schedule more accurately than a 60-minute persistence measure would result in more featherings and curtailments if actual scheduling was less accurate than the assumption. Hall, Oral Tr. at 49; Skidmore, Oral Tr. at 62. BPA lacks a basis under these circumstances to conclude that requirements customers bear the risk if the wind fleet scheduling accuracy during the rate period is worse than the assumption in the reserve forecast.

The real crux of the argument of PPC *et al.* seems to be that, even with DSO 216, nothing *prohibits* BPA from setting aside and deploying reserves in excess of the amount forecast in the rate case, and requirements customers bear financial risk under this scenario. PPC *et al.* Br., WP-10-B-JP11-01, at 36. PPC *et al.* express concern that BPA will be pressured to hold out excess reserves when wind generators are exceeding available system reserves, and that wind generators' statements about willingness to accept feathering and curtailment orders under DSO 216 will not insulate BPA from complaints. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 17. BPA acknowledges these concerns, but, as described in response to Issue 10 in section 13.2, BPA intends to set aside the amount of reserves associated with the rate case forecast and to manage the deployment of reserves to that level in accordance with DSO 216. BPA agrees that nothing prohibits it from setting aside and deploying additional reserves. BPA will not be motivated to hold and deploy additional reserves rather than applying the DSO 216 requirements, however, because the higher reserve levels increase risk to non-power operation and impose costs that BPA does not want to bear. Mainzer *et al.*, WP-10-E-BPA-41, at 34.

PPC *et al.* are correct that BPA currently is holding reserves for wind in excess of the amount that BPA estimated would be necessary for the current WI-09 rate period, but BPA has significantly improved and expanded its reserve forecast methodology since developing its estimate for the WI-09 rate. PPC *et al.* Br., WP-10-B-JP11-01, at 36; *see* McManus *et al.*, WP-10-E-BPA-23, at 5-6 (describing differences in the methodology used for WI-09 and the methodology used in the WP-10 proposal). Specifically, BPA has expanded its reserve forecast methodology to account for the imbalance capacity associated with scheduling error. McManus *et al.*, WP-10-E-BPA-23, at 5-6. BPA did not include the capacity associated with imbalance as a component in its estimate for WI-09. *Id.* Furthermore, the WI-09 rate was the product of a settlement to cover a one-year period, and no party agreed to any particular forecast of reserves in that case. The circumstances that will be in place in the FY 2010-2011 rate period are distinguishable from those when the WI-09 rate was established, and the record includes no credible basis to conclude that BPA will hold reserves above the amount assumed in the reserve forecast rather than applying the limitations required under DSO 216.

PPC *et al.* also claim that assuming better-than-demonstrated scheduling accuracy shifts risk to requirements customers, because it is contrary to cost causation principles. PPC *et al*. Br. Ex., WP-10-R-JP12-01, at 17-18. PPC *et al.* emphasize that this is important given the evidence that wind generators will tend to overuse reserves paid for by load compared to load's overuse of reserves paid for by wind generators. *Id*. at 18. Again, BPA's intended application of DSO 216 places the risk of the need for reserves in excess of the rate case forecast on wind generators and the loads they serve. Mainzer *et al.*, WP-10-E-BPA-41, at 32. Therefore, BPA disagrees that using a scheduling accuracy assumption that relies on application of DSO 216 and expectations of continued improvements in scheduling accuracy is inconsistent with cost causation principles. Wind generators will pay for the reserves that are set aside under the rate case reserve forecast, and those generators or the loads they serve will bear the cost of operational limitations under DSO 216 if the demand for reserves exceeds the forecast amount. *Id*. *at 3*2-33.

BPA also disagrees that the record demonstrates that wind will overuse reserves paid for by load. This argument fails to recognize the distinction between the allocation of the total reserve requirement forecast by Staff and the application of DSO 216. *Id*. at 36. The incremental standard deviation methodology that Staff uses to allocate the total reserve requirement between wind and load assesses the degree to which wind and load contribute to the overall reserves requirement and allocates the reserves accordingly. McManus *et al.*, WP-10-E-BPA-23, at 22. Staff uses this allocation to assign costs for ratemaking purposes. Mainzer *et al.*, WP-10-E-BPA-41, at 36. For purposes of DSO 216, however, BPA has consistently stated that BPA will use the total reserve requirement to determine when to apply the operational requirements. *Id*. The allocation of reserves for ratemaking purposes is not part of the DSO, and, to the extent that BPA is using the reserves set aside to meet its combined wind and load balancing obligations within an hour, the use of reserves does not unfairly shift costs. *Id*. at 36, 41-42.

The claims of PPC *et al.* provide no basis to preclude BPA from assuming for purposes of the reserve forecast that wind scheduling during the rate period will be more accurate than a 60-minute persistence model.

Decision

Requirements customers do not bear all the financial risk if BPA underestimates the wind reserves needed by adopting an assumption that the wind fleet will be scheduling more accurately than a 60-minute persistence model during the rate period.

Issue 4

What scheduling accuracy assumption should BPA use for purposes of the generation reserve forecast?

Parties' Positions

Iberdrola and NWG urge BPA to assume scheduling accuracy equivalent to a 30-minute persistence model for purposes of the reserve forecast. Iberdrola Br., WP-10-B-IR-01, at 12; NWG Br., WP-10-B-NG-01, at 14.

PPC *et al.* and NRU support adopting a scheduling accuracy assumption equivalent to a 60-minute persistence model. PPC *et al.* Br., WP-10-B-JP11-01, at 36-37; NRU Br. Ex., WP-10-R-NR-01, at 9.

Cowlitz and Snohomish support adopting a 45-minute persistence measure. Cowlitz Br. Ex., WP-10-R-CO-CC01, at 3; Snohomish Br. Ex., WP-10-R-SN-01, at 9.

The OPUC maintains that the record demonstrates that some wind generators are capable of scheduling at a level equivalent to 30-minute persistence and that the remainder can achieve 45-minute persistence accuracy. OPUC Br., WP-10-B-PU-01, at 13. The OPUC suggests that BPA adopt a rate that initially is based on a 45-minute persistence assumption but that may be changed to a 30-minute level during the rate period. OPUC Br. Ex., WP-10-R-PU-02, at 2.

LADWP recommends adopting an assumption of 60-minute persistence but supports adopting an assumption equivalent to 30-minute persistence "on a voluntary basis." LADWP Br., WP-10-B-LA-01, at 18.

MSR believes that the wind fleet can "easily meet" the 30-minute persistence measure, but MSR is willing to accept the 45-minute measure for ratemaking purposes. MSR Br. Ex., WP-10-R-MS-01, at 5.

BPA Staff's Position

BPA should adopt a scheduling accuracy assumption that reflects a 45-minute persistence model.

Evaluation of Positions

In its decisions on the previous issues, BPA has concluded that current wind fleet scheduling accuracy has improved to a 60-minute persistence measure and that there is a reasonable basis to expect scheduling accuracy to continue to improve during the rate period. BPA evaluates the recommendations regarding the appropriate scheduling accuracy assumption to use in the rate case reserve forecast against this backdrop.

PPC *et al.* argue that the only assumption that the record supports is that scheduling accuracy will remain static at the current 60-minute persistence measure. PPC *et al.* Br., WP-10-B-JP11-01, at 34-35. This position relies heavily on the evidence demonstrating the sustained improvement in current wind fleet scheduling accuracy but fails to assign any weight to the indications that some wind generators already are scheduling more accurately over shorter periods of time or the substantial evidence demonstrating the efforts and incentives to further improve scheduling during the rate period. Generators such as Iberdrola already have achieved accuracy that meets or improves upon a 45-minute persistence measure for certain periods. Froese *et al.*, WP-10-E-IR-01-CC01, at 31-32. Furthermore, NWG claims that the wind fleet as a whole may already exceed the 60-minute persistence measure at times. Dragoon, WP-10-E-NG-04, at 5. The wind fleet has demonstrated the ability to significantly improve scheduling accuracy in a relatively short period of time, and BPA and others are investing in infrastructure and incentives that will promote further improvements during the rate period. Froese *et al.*, WP-10-E-IR-01-CC01, at 28-29; WP-10-E-IR-04 (Response to Data Request No. IR-BPA-9); Mainzer *et al.*, WP-10-E-BPA-22, at 23. Based on all these factors, BPA is not adopting an assumption for the reserve forecast that scheduling accuracy will remain static at the 60-minute persistence level.

Staff generally believes that the scheduling accuracy assumption used in the reserve forecast should be reasonably related to current scheduling accuracy. Mainzer *et al.*, WP-10-E-BPA-41, at 32. Even with DSO 216 in place, BPA would be concerned about the potential for frequent and severe curtailments and other potential reliability impacts associated with holding reserves based on a scheduling accuracy assumption that departed dramatically from the accuracy that the wind fleet has actually demonstrated. *See id.* at 32-33.

The analysis of actual scheduling and generation data in the record demonstrates that certain wind generators have been able to achieve accuracy equivalent to 45-minute persistence levels at times. Froese *et al.*, WP-10-E-IR-01-CC01, at 31-32; Dragoon, WP-10-E-NG-04, at 5. Iberdrola maintains that it has improved its scheduling accuracy to between 30-minute and 45-minute persistence levels, and its facilities constitute almost half of the wind fleet. Iberdrola Br., WP-10-B-IR-01, at 12. Staff's analysis indicates that the accuracy of approximately five facilities was near the 45-minute persistence measure for the August 2008 to March 2009 period. McManus *et al.*, WP-10-E-BPA-42, at 41, Exhibit 10. Under these circumstances, the 45-minute persistence measure bears a reasonable relation to the scheduling accuracy demonstrated by certain generators, even if the wind fleet as a whole has not yet demonstrated this level of accuracy on a sustained basis. *Id.*

The record lacks credible evidence to demonstrate that the wind fleet as a whole has achieved accuracy equivalent to 30-minute persistence. No party seems to seriously contend that the wind fleet has scheduled that accurately on a sustained basis. *See* Froese *et al.*, WP-10-E-IR-01-CC01, at 31-32 (claiming that Iberdrola facilities are achieving scheduling accuracy equivalent to 45-minute persistence) *and* Dragoon, WP-10-E-NG-04, at 5 (claiming accuracy between 35- and 40-minute persistence for the wind fleet in a recent week). Staff's analysis indicates that only two facilities have achieved that level of accuracy. McManus *et al.*, WP-10-E-BPA-42, at 42, Exhibit 11. As a result, even though the evidence supports a conclusion that scheduling accuracy will continue to improve, adopting an assumption reflecting 30-minute persistence must be based on more than the evidence of actual scheduling accuracy.

NWG and Iberdrola urge BPA to forecast reserves assuming scheduling accuracy equal to a 30-minute persistence measure and to use the DSO 216 protocols to manage reserves to the amount forecast in the rate case. Hall, Oral Tr. at 32; Skidmore, Oral Tr. at 64. In a June 29, 2009, rate case workshop, BPA provided the parties with Staff's most up-to-date estimates of the feathering and curtailment events that could result under DSO 216 based on the 30-minute, 45-minute, and 60-minute persistence assumptions. This information was included in the record as Exhibit WP-10-BPA-E-69, and the Administrator urged all rate case parties to offer their views in their Briefs on Exceptions regarding the tradeoff between the Wind Balancing Service rate and the amount of feathering and curtailment under DSO 216; that is, the less reserves BPA holds out, and therefore the lower the Wind Balancing Service rate, the more feathering and curtailment is likely under DSO 216. *See* WP-10-M-BPA-14 at 1-2; WP-10-HOO-43 at 1-2.

Iberdrola and NWG are the only parties that will be directly impacted by the feathering and curtailments under DSO 216 that commented on the potential tradeoffs in their Briefs on Exceptions. Iberdrola Br. Ex., WP-10-R-IR-01, at 9; NWG Br. Ex., WP-10-R-NG-01, at 9. The investor-owned utilities and neighboring balancing authorities did not respond to the Administrator's request. Iberdrola and NWG are willing to accept the number of feathering and curtailments events that Staff estimated. Iberdrola Br. Ex., WP-10-R-IR-01, at 9; NWG Br. Ex., WP-10-R-NG-01, at 9. In addition, both parties acknowledged that the actual number of events may be more or less than the estimates and are willing to accept this risk. Iberdrola Br. Ex., WP-10-R-IR-01, at 9-10; NWG Br. Ex., WP-10-R-NG-01, at 9. NWG states that its members with wind generation will continue their commitment to improve scheduling accuracy. NWG Br. Ex., WP-10-R-NG-01, at 9. Iberdrola also has demonstrated a commitment to improve scheduling accuracy. Froese *et al.*, WP-10-E-IR-01-CC01, at 28-30.

Based on these representations, BPA is satisfied that the parties that will be directly impacted by orders under DSO 216 and that took advantage of the opportunity to comment on the issues have reviewed the most up-to-date information available and sufficiently acknowledged the tradeoffs between the rate level and the potential limitations under DSO 216. BPA also concludes that, given the ability to deploy DSO 216, it can maintain reliability even while setting aside the lesser amount of reserves associated with a 30-minute persistence scheduling accuracy. Under DSO 216, when BPA is close to exhausting the reserves it has set aside, it can instruct wind generators to reduce output (if they are overgenerating) or revise wind transmission schedules (if they are undergenerating). Therefore, BPA can carry a lower amount of reserves to manage the variability of wind generation. Mainzer *et al.*, WP-10-E-BPA-22, at 20-21. Through deployment of DSO 216, BPA can balance the system without the use of additional reserves.

BPA will adopt the 30-minute persistence measure for the scheduling accuracy assumption and rely on DSO 216 to manage the use of reserves to the amount associated with this assumption. This decision is based on a combination of four elements: the demonstrated scheduling accuracy of the wind fleet; the fleet's commitment to improving scheduling accuracy and the incentives BPA has put in place for improved scheduling accuracy; the reliability protocols of DSO 216; and the wind generators' agreement to greater curtailments under a 30-minute persistence scheduling accuracy. Adopting the 30-minute persistence assumption reduces the Wind Balancing Service rate and the amount of reserves that BPA will set aside for operations during the rate period.

PPC *et al.* believe that it will be difficult for BPA to order feathering and curtailment if DSO 216 is challenged or is the subject of a complaint and that BPA could face pressure to hold more reserves if BPA orders feathering or curtailment on a regular basis. PPC *et al*. Br. Ex., WP-10-R-JP12-01, at 17, 19. The OPUC states that the risk of adopting the 30-minute persistence assumption is "too great" given that it is unclear that all wind generators will be able to meet this level of scheduling accuracy by the beginning of the rate period. OPUC Br. Ex., WP-10-R-PU-01, at 2. As noted above, BPA is basing its decision on several elements, and given that BPA is setting rates for two years, it is not necessarily appropriate to base the rates solely on conditions that exist at the beginning of the rate period.

Nevertheless, BPA acknowledges the legitimate concerns regarding the frequent application of DSO 216. Therefore, BPA is retaining discretion to increase the amount of reserves it sets aside for operations and the level of the Wind Balancing Service rate to an amount consistent with a 45-minute persistence measure under certain circumstances. Chapter 20 of this Final ROD discusses this aspect of the Wind Balancing Service rate in detail.

Decision

BPA will assume wind generator scheduling accuracy equal to the 30-minute persistence measure for purposes of the generation reserve forecast. The Final Study will include a forecast of the reserve requirement using the 45-minute persistence assumption and a corresponding cost allocation in order to reflect the Administrator's discretion to change the rate and reserve amount during the rate period.

Issue 5

Whether the record supports the conclusion that improvements in scheduling accuracy can be attributed to BPA's publication of the proposed Wind Balancing Service rate.

Parties' Positions

NWG argues that the record includes no evidence to support the conclusion that publication of the proposed Wind Balancing Service rate contributed to the improvements in scheduling accuracy. NWG Br. Ex., WP-10-R-NG-01, at 5-6.

BPA Staff's Position

Publication of the proposed Wind Balancing Service rate contributed to the improvement in scheduling accuracy. Mainzer *et al.*, WP-10-E-BPA-41, at 15.

Evaluation of Positions

NWG maintains that there is no basis to conclude that the improvement in scheduling accuracy is attributable to BPA's publication of the proposed Wind Balancing Service rate. NWG Br. Ex., WP-10-R-NG-01, at 5-6. Iberdrola's testimony suggests the opposite conclusion:

> Q. Why has scheduling accuracy been low in the past?
>
> A. The analysis the WIT team performed on forecasting accuracy as part of its review of the Wind Integration rate methodology marked the first time many wind generators became aware of the level of accuracy of their wind schedules. *In addition, prior to the quantification of the impact of scheduling accuracy on the wind integration rate, the generation imbalance rate and penalty was the only incentive wind generators had by which to evaluate or improve scheduling accuracy.*

Froese *et al.*, WP-10-E-IR-01-CC01, at 27 (emphasis added). Iberdrola's testimony otherwise refers to the "financial incentive" that wind generators now have to improve accuracy, and it goes on to describe specific actions and investments Iberdrola already has made to improve its scheduling accuracy. *Id.* at 27, 28-30. Iberdrola also states that its facilities constitute almost half of the entire wind fleet, and that improvements in its scheduling will materially affect wind fleet accuracy as a whole. Iberdrola Br., WP-10-B-IR-01, at 12. Iberdrola referred to the incentive created by the Wind Balancing Service rate again in oral argument, stating that the company was getting the signal about the importance of accurate scheduling from the level of the Wind Balancing Service rate and the amount that it varies based on the scheduling accuracy assumption. Skidmore, Oral Tr. at 78.

Staff's testimony cited the incentive created by publication of the Wind Balancing Service rate as well. Mainzer *et al.*, WP-10-E-BPA-41, at 15. Staff noted that the current Generation Imbalance rate obviously had not provided sufficient incentive for wind generators to schedule accurately, because BPA had observed fairly inaccurate scheduling practices prior to September 2008. *Id.* at 15, 35. Staff also noted that it was not until BPA demonstrated the significant cost implications of poor scheduling and decided to implement DSO 216 that sufficient incentives were put in place for the wind community to improve scheduling. *Id.* at 15.

The record also demonstrates that the noticeable increase in scheduling accuracy occurred in September 2008, which coincides with the time that BPA was holding rate case workshops regarding the potential rate levels as well as when WIT began its awareness campaign. McManus *et al.*, WP-10-E-BPA-42, at 13. BPA believes under these circumstances that the record contains substantial evidence that the improvement in scheduling accuracy is attributable, in part, to the price signal from the proposed Wind Balancing Service rate.

Decision

The record contains substantial evidence to support the conclusion that the improvement in scheduling accuracy is attributable, in part, to the price signal from the proposed Wind Balancing Service rate.

13.3.2.4 Total Reserve Requirement Calculation

The reserve forecast methodology used for the Initial Proposal calculates the total reserve requirement by determining the *inc* and *dec* amounts for each hour of the day and then discarding 0.25 percent of the upper and lower values for each reserve component for each hour. Staff's rebuttal testimony proposes changing the calculation to use 99.5 percent of the total dataset for each reserve component rather than 99.5 percent of the values for each hour. Staff forecasts the total reserve requirement based on the maximum values of the 99.5 percent of data used under either method, but the proposed change discards data for extreme ramping events that fall outside the 99.5 percent of values for the total dataset. This proposed change reduces the forecast of the total reserve requirement.

Issue 1

Whether BPA's reserve forecast should account for the wind fleet as a whole or should reflect reserve needs for wind generators on an individual basis.

Parties' Positions

MSR maintains that the forecast of the total reserve requirement exceeds the necessary amounts of reserves because the methodology forecasts the reserve needs for the wind fleet as a whole rather than for each individual wind facility. MSR Br., WP-10-B-MS-01, at 11. MSR claims that if BPA "identified each wind plant and its unique characteristics, the analysis would show a much smaller within hour variation (a single wind plant compared to all generation.)" *Id*.

BPA Staff's Position

BPA must hold reserves in order to meet the needs of the wind fleet as a whole and maintain reliable operations in extreme conditions. McManus *et al.*, WP-10-E-BPA-23, at 2, 20-21. The forecast methodology is based on calculating the reserve need for the wind fleet as a whole for 99.5 percent of events. *Id*. at 20-21.

Evaluation of Positions

The record does not include evidence regarding the reserve need for individual wind facilities in the BPA Balancing Authority Area or a method for estimating the individual reserve need of wind projects that do not yet exist but that are expected to be online during the rate period.
To maintain reliability and meet reliability standards, BPA must hold out enough reserves to support all wind and load. McManus *et al.*, WP-10-E-BPA-23, at 2. Thus, BPA must forecast the reserve need of the entire wind fleet as a whole as opposed to adopting a reserve requirement based on the need of individual facilities. *Id*. at 20-21. Using the entire wind fleet captures any

synergies that increase the reserve requirement or diversities that reduce the reserve requirement compared to using individual facilities.

Decision

BPA's reserve forecast will account for the wind fleet as a whole.

Issue 2

Whether BPA should calculate the total reserve requirement using 99.5 percent of the total dataset for each reserve component for purposes of the reserve forecast.

Parties' Positions

Only one party commented on Staff's proposal in rebuttal testimony to calculate the total reserve requirement based on 99.5 percent of the *inc* and *dec* data of the total dataset for each reserve component as opposed to 99.5 percent of the data for each hour of the day. PPC *et al.* state that they have misgivings about the proposal and reserve the right to address it in future rate proceedings. PPC *et al.* Br., WP-10-B-JP11-01, at 38.

BPA Staff's Position

Staff proposes to calculate the total reserve requirement based on 99.5 percent of the *inc* and *dec* data for the total dataset for each reserve component as opposed to 99.5 percent of the data for each hour of the day. McManus *et al.*, WP-10-E-BPA-42, at 27.

Evaluation of Positions

Although PPC *et al.* express reservations about the method for calculating the total reserve requirement, no party expressly opposes this proposal. The revised calculation more accurately forecasts the total reserve requirement than the calculation proposed for the Initial Proposal. McManus *et al.*, WP-10-E-BPA-42, at 27. Although the same amount of data is used under either method, the methodology used in the Initial Proposal results in including some extreme ramping events that fall outside of the 99.5 percent of values for the total dataset. *Id.* The *inc* and *dec* amounts for such events should be discarded, because they are outliers when compared to the total dataset. *Id.* BPA agrees that the reserve forecast methodology should incorporate this method of calculating the total reserve requirement.

Decision

BPA will calculate the total reserve requirement using 99.5 percent of the total dataset for each reserve component for purposes of the reserve forecast.

13.3.2.5 Load Forecast Assumption

The Initial Proposal identifies a change to the load forecast assumption in the reserve forecast methodology that is necessary to better reflect actual operations. Staff was unable to incorporate this assumption in the methodology prior to initiating this proceeding, so the Initial Proposal includes the inaccurate assumption that the load forecast is updated only once per day. The load forecast is updated hourly in actual operations. Staff proposed changing the assumption in rebuttal testimony. The proposed modification decreases the forecast of the total reserve requirement but significantly increases the reserve requirement attributable to wind generation.

Issue 1

Whether BPA should modify the load forecast assumption used for the Initial Proposal to account for the hourly load forecast updates in operations, and whether it is discriminatory to use that assumption for the reserve forecast but not modify operations to account for the wind output 10 minutes prior to the hour.

Parties' Positions

NWG suggests that, because BPA proposes to adopt a load forecast assumption that recognizes that hydro duty schedulers receive updated load forecasts prior to each hour, BPA must modify its operations to account for updated wind forecasts prior to the hour as well. NWG Br., WP-10-B-NG-01, at 18. NWG states that BPA should either have wind generators provide 10-minute forecasts, or BPA should take 10-minute forecasts from the Supervisory Control and Data Acquisition System. *Id*. NWG also suggests that the hydro duty schedulers should use this updated data to adjust the hydro base points and tailor the use of reserves to reflect real-time operating data. *Id*. According to NWG, if "BPA has the capability to improve upon its load forecast assumptions and is receiving wind generation data from wind generators in time to make the same calculations for wind, there is no reason why BPA should not be able to extend the same treatment to its wind generator customers. Modifying the forecast assumptions for load but not for wind is discriminatory and indefensible." *Id*. at 19. NWG argues in its Brief on Exceptions that updating the load forecast 10 minutes before the start of the hour and after the end of trading does not reduce the load requirements. NWG Br. Ex., WP-10-R-NG-01, at 10.

MSR argues that wind and load are treated "differently." MSR Br., WP-10-B-MS-01, at 18. According to MSR, "BPA treats its preference load differently allowing it more flexible scheduling requirements. Load is allowed to change its schedules within the hour, essentially scheduling in 20 minute increments. Wind is not." *Id*.

PPC *et al.* support adoption of the new load forecast assumption, stating that it allows BPA to more accurately reflect the amount of capacity reserves set aside for load. PPC *et al.* Br., WP-10-B-JP11-01, at 37-38.

BPA Staff's Position

Incorporating the correct load forecast assumption into the reserve forecast methodology fixes the inaccurate assumption used in the Initial Proposal. Barton *et al*., WP-10-E-BPA-47, at 4. The change makes the load forecast assumption in the reserve forecast methodology more comparable to the assumption about schedules submitted for the wind projects. *Id*. Even if BPA received updated wind forecast information 10 minutes prior to the hour and updated the hydro base points based on this new information, the hydro duty schedulers could not tailor the use of reserves in the manner that NWG asserts. BPA must deploy wind balancing reserves based on the schedules submitted by the wind generators regardless of the updated information that BPA might receive before the hour. *Id.* at 5.

Evaluation of Positions

NWG suggests that for the proposed Wind Balancing Service rate to be non-discriminatory, BPA should adopt an operating procedure under which BPA obtains updated wind forecast information before the hour, use that information to adjust the hydro base points, and tailor the amount of reserves to the most up-to-date information. NWG Br., WP-10-B-NG-01, at 18-19. Proposed changes to BPA's operations are not before the Administrator for decision in this case. This proceeding sets BPA's rates. The discussion that follows addresses NWG's claims, but operational changes are not at issue in this proceeding.

Staff proposes the modification of the simplified load forecast assumption found in the Initial Proposal to more accurately reflect BPA's actual operations. McManus *et al.*, WP-10-E-BPA-42, at 24-25; McManus *et al.*, WP-10-E-BPA-23, at 24. The reserve forecast methodology used in the Initial Proposal assumes that wind generation forecasts are updated hourly with the best available data, but that the load forecast is updated only once per day. Barton *et al.*, WP-10-E-BPA-47, at 3-4. In actual operations, however, the load forecast assumption is updated hourly as well. *Id.* The hydro duty schedulers obtain the load forecast 10 minutes prior to the hour and use it to calculate the estimated load at 10 minutes, 30 minutes, and 50 minutes past the hour. McManus *et al.*, WP-10-E-BPA-42, at 25. Adopting the load forecast assumption proposed by Staff will help ensure that rate case assumptions more accurately reflect operations, will reduce the forecast of the total reserve requirement, and will more accurately reflect the extent to which load contributes to that total reserve requirement. Barton *et al.*, WP-10-E-BPA-47, at 2-3.

NWG argues that incorporating the new load forecast assumption in the reserve forecast methodology is discriminatory. NWG Br., WP-10-B-NG-01, at 19. In reality, however, adopting the new load forecast input actually results in treating load and wind more comparably in terms of ratemaking and reserve forecast methodology assumptions. Barton *et al.*, WP-10-E-BPA-47, at 4. The methodology already assumes that wind generation forecasts are updated hourly with the best available data. *Id.* Adopting the new load forecast assumption merely corrects the inaccurate assumption that the load forecast is updated only once per day. *Id.* As Staff testified, the hourly update to the load forecast is analogous to the hourly update to other load schedules, including the hour-ahead changes to the wind generation schedules. *Id.* at 3. Adopting the new load forecast assumption ensures that the reserve forecast methodology reflects the actual information used by the hydro duty schedulers. *Id.* at 4.

NWG's concern focuses on differences in how the wind generation and load are treated in BPA's operations rather than in its ratemaking assumptions or methodologies. NWG urges BPA to modify its operations to obtain updated wind generation forecast information prior to the hour and use the updated data to adjust the hydro base points and better manage the use of reserves. NWG Br., WP-10-B-NG-01, at 18.

Although NWG's suggestion may result in more comparable treatment of wind generation and load in operations, distinctions in the requirements that BPA follows with respect to wind generation and load justify the different operational practices. When the hydro duty scheduler receives updated load forecast information 10 minutes before the hour, the scheduler can adjust the hydro base points and have a meaningful effect on the amount of reserves deployed, because BPA is serving the load in its Balancing Authority Area and can control AGC-responsive generation to the actual load. BPA manages its need to deploy within-hour balancing reserves for load under these circumstances by adjusting generation to reflect actual load. Barton *et al.*, WP-10-E-BPA-47, at 3. This practice is consistent with operational procedures that have been in place for many years. *Id.* at 6.

BPA cannot follow the same process for wind generation, because the deployment of balancing reserves is based on the schedules submitted for wind resources. *Id.* at 5. Regardless of the updated information that BPA may receive prior to the hour, BPA's deployment of wind balancing reserves remains tied to the schedules submitted by wind generators. *Id.* Obtaining updated wind forecast information may help to inform the hydro duty schedulers that an imbalance would occur in the next hour, but the imbalance relative to the submitted schedule would persist without some adjustment to the schedule. *Id.* The hydro duty schedulers have no ability to adjust wind generators' schedules under current WECC scheduling guidelines. *Id.*

NWG makes clear that it is not suggesting that BPA adjust the schedules of the wind generators to reflect the updated information on an hourly basis. NWG Br., WP-10-B-NG-01, at 18. NWG instead suggests that BPA modify the hydro base points as a result of the updated information and tailor the use of reserves to reflect this real-time data. *Id.* NWG points out that BPA, not WECC, establishes the process for setting the hydro base points. *Id.* Even if BPA were to adjust the hydro base points based on updated information as NWG suggests, however, this adjustment would not lead to a more tailored deployment of reserves based on real-time operating data. BPA would continue to deploy wind balancing reserves based on the wind generation schedules for the hour. Cross Ex. Tr. at 189-190. The wind generation base points are tied to the wind schedules, and the hydro duty schedulers currently do not adjust those base points to reflect updated wind generation forecast data, in part because the hydro duty schedulers must balance to the wind generation schedules. Barton *et al.*, WP-10-E-BPA-47, at 5. This is different from BPA's deployment of reserves for load, because BPA can adjust other generation to reflect the actual load that BPA is serving in the Balancing Authority Area.

NWG also argues that BPA should not adopt the load forecast assumption because updating the load forecast 10 minutes before the hour "does not reduce the total load reserve requirement." NWG Br. Ex., WP-10-R-NG-01, at 10. NWG made similar statements in testimony, arguing that adopting the load forecast assumption "reduces the level and cost of reserve deployment, but it does not change the total amount of reserve that is needed" and "does not directly affect the total load reserve requirement." Dragoon, WP-10-E-NG-05, at 2, 5. NWG's Brief on Exceptions does not explain why NWG believes that this point is significant, but the record demonstrates that NWG is mistaken about the affect on the reserve requirement, and NWG's testimony appears to rely on this mistaken assumption. *See* Dragoon, WP-10-E-NG-05, at 2, 5; *see also* McManus *et al.*, WP-10-E-BPA-42-E01, Exhibits 15 and 16; and Exhibits 23 and 24 (showing the total reserve requirement and the reserve requirement for load under the "old" and "new" assumptions). Adopting the correct load forecast assumption reduces both the total reserve requirement and the reserve requirement for load. *See* McManus *et al.*, WP-10-E-BPA-42-E01, Exhibits 15 and 16; and Exhibits 23 and 24.

Finally, NWG argues that adopting the load forecast assumption is impermissible because it increases the reserve requirement for wind generation but changes only the assumptions related to load. NWG Br., WP-10-B-NG-01, at 17. NWG argues that the load forecast assumption violates the equitable allocation standard in the Northwest Power Act for this reason and that "there is no cost causation" in this situation. *Id*. at 17-18. BPA addresses NWG's argument about violating the Northwest Power Act in the discussion of the next issue. NWG's argument that the load forecast assumption improperly results in an increase in reserves for wind generators when the assumptions for wind generators are unchanged is not well-founded. Staff's reserve forecast methodology is based on developing an estimate of the total (wind and load) reserve requirement to maintain reliability, and the record demonstrates that the effect of the load forecast assumption is no different from other assumptions made for wind and load. For example, the reserve requirement attributable to load increases as the wind scheduling accuracy assumption moves from a two-hour persistence measure to a 30-minute measure. McManus *et al.*, WP-10-E-BPA-42-E01, Exhibit 24. The record provides no basis to reject the new load forecast assumption because that assumption will affect the reserve requirement for wind.

MSR's claims that wind generators and load are treated differently, and that wind generators should be permitted to change their schedules within the hour, are not compelling for many of the reasons described previously. MSR Br., WP-10-B-MS-01, at 18. Although BPA and its stakeholders will be working on intra-hour scheduling capabilities in the future, those capabilities do not currently exist. *See* WP-10-E-IR-04 (Response to Data Request No. IR-BPA-9).

The evidence in the record demonstrates that the new load forecast assumption will more accurately reflect BPA's actual operations and will result in a more accurate forecast of the reserve requirements for the rate period. NWG does not appear to dispute these claims. The distinctions in the requirements that apply to balancing wind generation and load are the basis for the differences in the actions that the hydro duty schedulers take in setting up the system before the hour. Adopting ratemaking assumptions that better reflect actual operations is not discriminatory.

Decision

BPA will modify the load forecast assumption in the reserve forecast methodology to account for hourly load forecast updates. It is not discriminatory to account for hourly load forecast updates but not modify BPA's operations to apply similar treatment to wind generators.

Issue 2

Whether the accounting for hourly load forecast updates in the reserve forecast methodology violates the equitable allocation standard in section 7(a)(2)(C) of the Northwest Power Act.

Parties' Positions

NWG argues that adopting the new load forecast assumption violates the equitable allocation standard in section 7(a)(2)(C) of the Northwest Power Act. NWG Br., WP-10-B-NG-01, at 19.

BPA Staff's Position

Equitable allocation of BPA's costs is a legal issue. The new load forecast assumption is an input to the reserve forecast methodology.

Evaluation of Positions

Section 7(a)(2)(C) of the Northwest Power Act requires BPA to, "insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system." 16 U.S.C. § 839e(a)(2)(C). The effect on BPA's reserve forecast of modifying the load forecast assumption is to more accurately determine the balancing reserves necessary to support wind generation and load. There is no cost shift between Federal and non-Federal power users of the transmission system that would violate the equitable allocation standard under the Northwest Power Act. *See* section 20.1.3.2 for a detailed discussion of 7(a)(2)(C) of the Northwest Power Act.

Decision

Accounting for hourly load forecast updates in the reserve requirement forecast does not violate the equitable allocation standard in section 7(a)(2)(C) of the Northwest Power Act.

13.3.2.6 Allocation of Total Reserve Requirement Between Wind and Load

Staff proposes to use incremental standard deviation to allocate the total reserve between wind generation and load. This method focuses on allocating to load and wind generation the amount that each contributes to the total reserve requirement.

Issue 1

Whether BPA should use incremental standard deviation to allocate the total reserve requirement between wind generation and load.

Parties' Positions

NWG opposes Staff's proposal to use incremental standard deviation to allocate the total reserve requirement between wind generation and load. NWG Br., WP-10-B-NG-01, at 4. NWG advocates allocating to wind the incremental need for reserves above the amount historically held for load, reflecting the precise amount of each component's reserve need as opposed to the approximation that Staff proposes. Dragoon, WP-10-E-NG-01, at 19-20.

PPC *et al.* and Cowlitz support using incremental standard deviation and oppose NWG's proposal. PPC *et al.* Br., WP-10-B-JP11-01, at 39; Cowlitz Br., WP-10-B-CO-01, at 10-11.

PPC *et al.* state that Staff's proposed methodology is a fair and equitable approach to allocation and that NWG's proposal systematically over-allocates reserves to load. PPC *et al.* Br., WP-10-B-JP11-01, at 39. Cowlitz states that NWG is incorrect that the incremental standard deviation method "is merely an approximation" and that the ratemaking philosophy implied in what NWG advocates is "fundamentally wrong." Cowlitz Br., WP-10-B-CO-01, at 11.

BPA Staff's Position

Staff uses the incremental standard deviation to allocate the forecast reserve requirement. McManus *et al.*, WP-10-E-BPA-23, at 22. The incremental standard deviation is a portfolio-based approach that identifies the relative drivers behind the Balancing Authority Area's need for reserves. *Id.*

Evaluation of Positions

The methodologies proposed by Staff and NWG represent two fundamentally different perspectives on allocating the forecast reserve requirement. The incremental standard deviation measures how much the load and wind generation contribute to the total load net wind reserve requirement, based on the sensitivity of the total reserve to variation in the individual components. McManus *et al.*, WP-10-E-BPA-23, at 21. By examining the contribution of each component to the total reserve need, Staff's method recognizes that the load and wind error signals may not always move in the same direction. The result is a total (load and wind generation) reserve requirement that is less than the sum of the individual components for wind generation and load. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 22-23.

NWG criticizes the incremental standard deviation approach on several grounds, but all of NWG's criticisms appear tied to the perspective that wind should be allocated no more reserve than the incremental amount above that held for load. NWG claims that using the incremental standard deviation is "unprecedented" in terms of allocations used by other utilities, implying that Staff's proposed allocation is out of step with an industry standard. Dragoon, WP-10-E-NG-01, at 18-19. NWG suggests that other studies allocate to wind only the incremental reserve above that needed for load. *Id.* Staff's review of the studies that NWG relies on as precedent found that those studies either did not address allocation or did not provide any reasoning or rationale for the allocation chosen. McManus *et al.*, WP-10-E-BPA-42, at 21. As PPC *et al.* recognize, BPA is at the forefront of wind integration in terms of the wind penetration levels expected during the rate period. Baker *et al.*, WP-10-E-JP6-1, at 5-6. It is understandable, under these circumstances, that BPA would develop methodologies to resolve unique issues, and the record does not demonstrate any industry standard for allocating reserve amounts between wind and load.

NWG's claim that the incremental standard deviation is designed to assess portfolio risk in the financial services industry provides no basis to conclude that the incremental standard deviation produces a flawed or inaccurate allocation. NWG Br., WP-10-B-NG-01, at 4. In fact, NWG does not claim that Staff's alleged misapplication of incremental standard deviation results in any particular error in the allocation. NWG instead claims that misapplying incremental standard deviation results in approximating the amount to allocate to wind rather than using the precise amount of the wind's actual reserve requirement. Dragoon, WP-10-E-NG-01, at 20-21. According to NWG, the precise amount is the incremental reserve above that historically allocated to load. *Id*. Again, NWG's primary complaint about the incremental standard deviation is that it allocates to wind more reserve than the increment above that needed for load. *Id*.

The incremental standard deviation measures the contribution of load and wind to the total reserve requirement based on the sensitivity of the total reserve to variation in the individual components. McManus *et al.*, WP-10-E-BPA-23, at 21. Using the incremental standard deviation captures the diversification of the load and wind error signals, resulting in a total (load and wind) reserve requirement that is less than the sum of the individual components for wind and load. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 22-23. Neither NWG nor any other party appears to dispute Staff's claims about the usefulness of incremental standard deviation to reflect the contribution of each component or the effect of capturing the diversity in the error signals for wind and load. In fact, PPC *et al.* specifically identify the "netting" of the variation in the wind and load as a benefit to both load and wind. PPC *et al.* Br., WP-10-B-JP11-01, at 39 ("Because both wind generation and load contribute to the savings in the total reserve requirement produced by the netting of their variations, both should share that savings."). This philosophy and its benefits to load and wind weigh heavily in favor of adopting Staff's approach.

In addition, Staff, PPC *et al.*, and Cowlitz identify weaknesses in NWG's proposal. McManus *et al.*, WP-10-E-BPA-42, at 20; PPC *et al.* Br., WP-10-B-JP11-01, at 39; Cowlitz Br., WP-10-B-CO-01, at 11. If the goal of the allocation methodology is that load and wind should each be allocated the share of reserve that reflects each component's contribution to the total system error, NWG's proposed allocation understates the reserve requirement for wind. *Id*. NWG suggests that BPA first consider the reserve for load in isolation, which results in load receiving no benefit of the diversity resulting from recognizing both load and generation. McManus *et al.*, WP-10-E-BPA-42, at 20. Furthermore, the pricing implications potentially associated with NWG's proposal appear to increase costs significantly for each new wind facility that uses BPA's wind balancing services. The pricing implication of NWG's proposal is that each new wind facility would likely bear the added costs of increasingly expensive sources of reserves. *Id*. at 22.

BPA does not agree with the fundamental premise of NWG's proposal that wind should be allocated only the incremental amount of reserve above that traditionally held for load. Using incremental standard deviation helps to allocate the total reserve requirement based on the contribution of each component to the total, and this is a reasonable means of allocating reserves.

<u>Decision</u>

BPA will use incremental standard deviation to allocate the total reserve requirement between wind generation and load.

Issue 2

Whether it is discriminatory to allocate costs for imbalance capacity to wind generators through the Wind Balancing Service rate but not allocate capacity costs to load and other generation customers.

Parties' Positions

NWG argues that the Wind Balancing Service rate is discriminatory because it requires wind generators to pay for imbalance capacity without requiring the same of non-wind generators taking Generation Imbalance Service or native load customers taking Energy Imbalance Service. NWG Br., WP-10-B-NG-01, at 28.

BPA Staff's Position

Staff maintains that the Wind Balancing Service rate is not discriminatory. Mainzer *et al.*, WP-10-E-BPA-41, at 27; McManus *et al.*, WP-10-E-BPA-23, at 6.

Evaluation of Positions

Staff's observations of actual operations indicate that dispatchable generators do not contribute to the overall reserve requirement. McManus *et al.*, WP-10-E-BPA-23, at 6-7. The record contains no evidence to the contrary, and Staff's testimony provides a valid basis to distinguish wind from other generating resources.

The premise of NWG's argument with respect to power customers taking Energy Imbalance service is flawed. *See* Mainzer *et al.*, WP-10-E-BPA-41, at 27. A substantial amount of reserves are set aside to follow load; such reserves form the allocator for the costs of providing reserves for load; and the cost of carrying those reserves is allocated to and recovered through power rates paid by power customers. *Id*. For a detailed discussion of imposition of a capacity charge on load for Energy Imbalance, *see* section 13.4.2.

Because load is recovering its allocated share of the costs of reserves, BPA disagrees with NWG that the Wind Balancing Service rate discriminates against wind because it assesses a charge for imbalance capacity that is not assessed against other resources or load.

Decision

Allocating costs for imbalance capacity to wind generators through the Wind Balancing Service rate is not discriminatory. BPA recovers the costs of the capacity associated with reserves set aside for load through power rates paid by power customers.

13.4 Wind Balancing Service Pricing Methodology

13.4.1 Introduction

The pricing methodology for wind balancing reserves includes embedded costs based on the amount of *inc* reserves forecast for the rate period. It also includes the variable costs that measure the impact on generator efficiency and the shift of water from HLH to LLH associated with providing wind reserves for both *inc* and *dec* reserves. Mainzer *et al.*, WP-10-E-BPA-22, at 12. The embedded cost portion of this methodology is consistent with BPA's approach to pricing reserves in the WP-02, WP-07, and WI-09 rate cases. For regulating reserves in the WP-02 and WP-07 cases, BPA included an adder for lost efficiency and additional maintenance caused by cycling units. Prior to settlement in the WI-09 case, Staff proposed to include this same adder for wind balancing reserves. For the FY 2010-2011 rates, Staff proposes to drop this adder charge and replace it with a variable cost component based on analysis of the efficiency losses and cost shifts imposed by carrying large amounts of reserves.

The pricing of the cost allocation for Wind Balancing Service is consistent with the pricing methodology for regulation and Operating Reserve. Any changes to the pricing methodology would be reflected in all of these generation input cost allocations.

As discussed in section 13.2, BPA is facing an unprecedented increase in the amount of wind generation interconnecting in its Balancing Authority Area. BPA's Preliminary Needs Assessment projects that the FCRPS has enough capacity and flexibility to support the projected wind development in the FY 2010-2011 rate period, but in the near future other capacity resources will be needed to meet BPA's obligations to provide load service and reserves for the wind fleet. *See* Dragoon, WP-10-E-NG-01-AT02, at 3-4. BPA and/or the wind generators will likely have to acquire additional resources for reserves during the FY 2012-2013 rate period. In the FY 2010-2011 rate period, BPA and the wind generators must lay the groundwork for adding resources to provide balancing reserves.

BPA's strategy for allocating cost to the Wind Balancing Service is based on cost causation principles. Wind generators must pay their fair share of the system cost because any under-recovery from the wind generators would be recovered through BPA's power rates.
In developing a pricing methodology, BPA also must recognize that the FCRPS may be insufficient to meet the needs of all uses in the near future.

13.4.2 <u>Issues</u>

<u>Issue 1</u>

Whether the 120-hour peaking capacity is an appropriate measurement for system capacity and allocating embedded costs.

<u>Parties' Positions</u>

MSR claims that the 120-hour peaking capability of the Big 10 hydro projects is not affected by wind generators on the system, stating that BPA has a sustained capacity (energy storage for 120 hours) limit of approximately 8,363 MW, and that is an issue for BPA with or without wind. MSR Br., WP-10-B-MS-01, at 10-11.

NWG states that the evidence on the record does not support the use of 120-hour peaking capability to calculate the wind integration rate. NWG states that the 120-hour peaking capability reflects BPA's ability to meet sustained peak loads, but does not represent the measure of BPA's ability to meet the within-hour balancing requirements for wind generation. NWG Br., WP-10-B-NG-01, at 19-20.

NWG argues in its Brief on Exceptions that BPA's use of the 120-hour peaking capability is arbitrary and capricious, because BPA has not demonstrated how the provision of wind reserves reduces the 120-hour peaking capability. NWG Br. Ex., WP-10-R-NG-01, at 10-11. NWG claims that a megawatt of wind reserves is not equivalent to a megawatt of sustained peaking capability, there is no evidence demonstrating such equivalence, and thus there is no evidence in the record supporting the use of the 120-hour peaking capability as the correct measure for the embedded cost methodology. *Id.* at 11.

BPA Staff's Position

The 120-hour peaking capability of the system is an appropriate allocation measure for firm capacity uses of the system. Klippstein *et al.*, WP-10-E-BPA-24, at 8; Klippstein *et al.*, WP-10-E-BPA-43, at 2-4. This is the same embedded cost method used in the WP-02, WP-07, and WI-09 cases. The 120-hour peaking capability accounts for non-power constraints and is representative of the available capacity for purposes of planning the system. Klippstein *et al.*, WP-10-E-BPA-24, at 8.

Evaluation of Positions

MSR's claim that the 120-hour peaking capability is not affected by wind generators on the system appears to be based on a misunderstanding of how the 120-hour peaking capability is calculated. The 120-hour peaking capability is a product of the HYDSIM and HOSS models, which are computer models that simulate hydro operations based on historical streamflow data and known limitations on the hydro system. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 50-54. The HYDSIM and HOSS models use the generation reserves forecast, including wind balancing reserves, as inputs to determine the capacity available after all non-power constraints and reserve requirements are met. *Id.* at 52. The embedded cost pricing methodology then adds the available capacity and the reserve requirements to allocate costs on a per-unit basis. *Id.* at 56-57 and Table 3.7. Thus, the 120-hour peaking capability is affected by the forecast of wind balancing reserves, and the results of the embedded cost pricing methodology depend on the reserve needs of the wind fleet.

The Initial Proposal and Staff's rebuttal testimony support and justify the use of the 120-hour peaking capability. In rebuttal testimony Staff explains:

> The 120-hour peaking capability is not a shortage calculation. Rather, it is an average of the highest 120 hours of generation and may in fact exceed load, that the system could meet based on assumed water conditions and assumed constraints. The monthly 120-hour peaking capability amounts are a measure of how well the Federal Columbia River Power System (FCRPS) can meet typical peaks day after day. The 120-hour peaking capability is influenced by both available energy and capacity. We recognize that there are several uses of the system, and some uses of the system require only capacity; others require capacity with flexibility, such as wind reserves and other generation inputs; and others

> require both capacity and energy, such as load service. The Embedded Cost Pricing Methodology was not intended to be a capacity or energy study. The Embedded Cost Pricing Methodology is an allocation of a defined set of costs and a defined set of uses of system capacity, which include load service and generation inputs for the Balancing Authority.

Klippstein *et al.*, WP-10-E-BPA-43, at 2.

The 120-hour peaking capability has been used in three previous rate proceedings. 2002 Final Power Rate Proposal, Wholesale Power Rate Development Study, WP-02-FS-BPA-05, at 71-95; 2007 Final Power Rate Proposal, Wholesale Power Rate Development Study, WP-07-FS-BPA-05, at 92-114. The WI-09 case was settled, but the Initial Proposal for that case used the same embedded cost methodology as the WP-07 case.

NWG asserts that the 120-hour peaking capability is an appropriate measure for BPA's ability to meet peak loads on a sustained basis but is not appropriate for measuring within-hour balancing requirements. NWG Br., WP-10-B-NG-01, at 20. This assertion suggests there is no relationship between capacity needs for loads on a sustained basis and capacity needed to support within-hour deviations of the wind fleet. Reliable operation of the system requires that the capacity inventory must be available to meet all uses. Staff explains in the Initial Proposal that:

> For operational reliability, BPA has identified 120-hour peaking capability as a critical measure to determine resource availability to meet sustained peak loads, because BPA must operate the system to meet peak loads over an extended period of time. Therefore, we are proposing to use the 120-hour peaking capability as a measure of the system's sustained capacity when allocating costs to all capacity uses of the system. The peak load period is best characterized by the six peak hours per day. Thus, to obtain a monthly value, we averaged the load-serving capability of the system for the six peak hours of each week day, for five days per week, for four weeks per month. This yields the 120-hour peaking capability. Providing reserves is a firm use of the system and BPA must plan operation of the system to meet both reserve requirement and firm peak loads. BPA plans are based on meeting monthly peak loads, not a single peak hourly load. Therefore using 120-hour peaking capability to calculate the unit cost of Regulating and Wind Balancing Reserves is an appropriate measure of the system capacity capability.

Klippstein *et al.*, WP-10-E-BPA-24, at 8.

NWG cites to a line of questioning in cross examination and a BPA data response to support its assertion that there is no evidence in the record to support the use of the 120-hour peaking capability for the allocation of embedded costs to wind generation. NWG Br., WP-10-B-NG-01, at 20, fn. 70. In cross examination, NWG asked Staff if they had performed any analysis to quantify the effect on the availability of 120-hour peaking capability of providing each of the wind balancing reserve components. Cross Ex. Tr. at 136. Staff responded that no analysis had been performed. *Id*. The fact that separate analysis was not performed to determine the impact on the 120-hour peaking capability does not mean that use of the 120-hour peaking capability is not supported by the record. As described above, 120-hour peaking capability is produced from the HYDSIM and HOSS models. The reserve needs determined in the Generation Inputs Study and Study Documantaion, WP-10-E-BPA-08, section 2, are used as inputs to these models and are therefore taken into account to determine the 120-hour peaking capability. This is simply an allocation methodology used to allocate the costs of specific generating units to various reserve uses. Because the reserves are accounted for in the underlying models, there is no need to provide additional analysis quantifying the effect on the 120-hour peaking capability of providing the reserves.

The data response cited by NWG addresses the same question that was asked in cross examination. WP-10-E-NG-16 (Response to Data Request No. NG-BPA-66). The request states, "Please provide all analysis, documentation, and evidence BPA used to quantify the effect of providing regulation, following, and imbalance reserves on the availability of 120-hour peaking capability." Staff responded:

> there was no analysis on the effect on the 120-hour peaking capability of providing regulation, following and imbalance reserves. The modeling of the hydro system in HYDSIM/HOSS assumed all regulation, following and imbalance reserve requirements were met. As a result, the 120-hour peaking capacity value produced by HOSS includes any affect these reserves have on the system.

Id. The fact that no separate analysis of the effects of providing the reserves was performed does not mean that the record does not support the use of the 120-hour peaking capability, because the forecast reserve amounts were included in the studies from which the 120-hour peaking capability is derived.

The 120-hour peaking capability is a reasonable allocation methodology for uses of a hydro system that reflects the fact that BPA must manage the hydro system for more than a single hour of meeting loads and providing capacity reserves. Other methods could be used, but the record of this proceeding supports the 120-hour peaking capability method, and it has been the allocation methodology used in past rate cases.

NWG's Brief on Exceptions reasserts the argument raised in its Initial Brief and claims that BPA has not demonstrated that each megawatt of wind reserves is equivalent to consuming a megawatt of sustained peaking capacity. NWG Br. Ex., WP-10-R-NG-01, at 11. NWG argues that sustained peaking capability is largely limited by energy availability over a week, and balancing services tend to be virtually energy neutral over that time frame, so it is unlikely that they are equivalent, and there is no evidence demonstrating that they are equivalent. *Id*. NWG's argument suggests that to support the use of the 120-hour sustained peaking capability BPA must prove that the amount of reserves BPA maintains for the Wind Balancing Service has a one-to-one corresponding impact on BPA's sustained peaking capacity. This is a misleading assertion.

As described above, the reserve needs calculated in the generation reserve forecast for all ancillary services and control area services, including load following, are included in the HYDSIM and HOSS models to simulate the actual operating capability of the hydro system. Generation Inputs Study and Study Documantaion, WP-10-E-BPA-08, at 52-53. NWG's argument fails to recognize that operating the hydro system to provide Wind Balancing Service and other generation reserves requires BPA to hold out this capacity every hour, whether it is deployed or not. Holding out this capacity has a sustained effect on the hydrosystem capability that is accounted for in the HOSS model. The fact that balancing services are virtually energy neutral over a week or a month is immaterial, because BPA must withhold this capacity every hour, and it may be deployed at any time. Staff explained that:

> We did not intend to distinguish between instantaneous capacity, energy, and uses of the system that use a combination of capacity, energy and flexibility. The Embedded Cost Pricing Methodology was designed to identify all capacity uses of the system and allocate costs based on those uses of the system. We chose to base the Embedded Cost Pricing Methodology on the 120-hour peaking capability, which represents a measurement that is a blend of capacity and energy.

Klippstein *et al.*, WP-10-E-BPA-43, at 3.

Because BPA's resources are an interconnected hydro system, and BPA must withhold capacity for Wind Balancing Service for all hours, it makes sense to base this cost allocation on a measurement of the system's sustained peaking capability. The 120-hour sustained peaking capability was not created to specifically allocate costs to wind. BPA has been employing this metric as an allocation methodology for capacity uses since long before capacity for wind generation was recognized as a separate system cost. Changing the amount of reserves used in the HYDSIM and HOSS models does change the 120-hour sustained peaking capability, but the 120-hour sustained peaking capability is meant to measure all uses of the hydro system, and it is not logical that all uses of the system would have the same impact on the 120-hour sustained peaking capability. The 120-hour sustained peaking capability is a reasonable cost allocation methodology, and using it to allocate embedded costs to the Wind Balancing Service rate is not arbitrary and capricious.

Decision

The 120-hour peaking capability is an appropriate measurement for system capacity and allocating embedded costs. BPA will use the 120-hour peaking capability to allocate system costs to the Wind Balancing Service rate.

Issue 2

Whether BPA should use the instantaneous capacity of the Big 10 projects to allocate embedded costs for generation inputs, rather than the 120-hour peaking capability.

Parties' Positions

NWG argues that there is no evidence in the record to support 120-hour peaking capacity as a cost allocation measure, so BPA should use the instantaneous capacity of the Big 10 resources to allocate costs for the Wind Balancing Service rate. NWG Br., WP-10-B-NG-01, at 19-20. NWG clarifies in its Brief on Exceptions that it understands that the instantaneous capacity of the FCRPS is limited by certain non-power constraints, and adjusting for these constraints is reasonable. NWG Br. Ex., WP-10-R-NG-01, at 11. NWG states that BPA should use the instantaneous capacity of the Big 10 resources, adjusted for non-power constraints, to allocate embedded costs to wind generators. *Id*. at 11-12.

BPA Staff's Position

The instantaneous capacity of the Big 10 resources is not an accurate measurement of the capacity that is available to provide balancing reserves and meet BPA's other obligations. Klippstein *et al.*, WP-10-E-BPA-43, at 4-5. The 120-hour peaking capability of the system is an appropriate allocation measure for firm capacity uses of the system. Klippstein *et al.*, WP-10-E-BPA-24, at 7-8; Klippstein *et al.*, WP-10-E-BPA-43, at 2-3, 5.

Evaluation of Positions

Staff's proposal limits the costs allocated to Wind Balancing Service and Regulating Reserve Service to those associated with the Big 10 resources. Klippstein *et al.*, WP-10-E-BPA-24, at 3. These services require generation that is equipped with AGC, and the Big 10 resources are the only generators that BPA uses for these purposes. *Id*. Because of non-power constraints, generator outages, and variability of streamflows, the Big 10 resources are never capable of providing the full instantaneous capacity referred to by NWG. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 51. The instantaneous capacity of these projects is roughly 18,000 MW. *Id*., Table 3.1, line 16. In recent years, however, with non-power constraints similar to those projected for the FY 2010-2011 rate period, the FCRPS had a maximum hourly generation of 12,451 MW on December 20, 2008. Klippstein *et al.*, WP-10-E-BPA-43, at 4.

If the FCRPS was a thermal system, installed capacity may be an appropriate divisor for a cost allocation methodology. As a hydro system, however, the assumed availability of FCRPS system capacity must account for non-power constraints, generator outages, and seasonal limitations on streamflow so the forecast of available capacity is representative of the system capability. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 51. The available capacity of the Big 10 resources varies significantly over the course of the year primarily because of streamflows and non-power constraints, such as fish operations, that affect operations differently depending on the time of the year. These effects are represented by the Operational Adjustments row shown on Tables 3.1 and 3.2 line 42, WP-10-E-BPA-08. The adjustment on line 42 shows the difference between the instantaneous capacity and the hydro system adjusted capacity on a monthly average basis. *Id*. at 54.

Costs should be allocated based on the forecast of actual system capability rather than an amount of capacity that the system is not capable of producing or maintaining. Therefore, it would be unreasonable to base the allocation of costs on the instantaneous capacity of the Big 10 resources. The Staff proposal uses the average of peak usage over all months of the rate period. *Id*. Because the 120-hour peaking capability used in the embedded cost pricing methodology is a single month average value, this method may actually overstate the ability of the system to meet load and reserve obligations in some months. *Id*.

Another approach that BPA could consider is using a one-hour measurement by taking the highest hour from the 120-hour peaking capability. The one-hour measurement of the highest hour from the 120-hour peaking capability would be consistent with what NWG advocates for in its Brief on Exceptions. NWG Br. Ex., WP-10-R-NG-01, at 11. This would account for all seasonal flows and non-power constraints, but would still limit the measure to an operationally grounded one-hour value. The problem with this approach is that it does not recognize that the hydro system must be used on a sustained basis to both provide reserves and meet BPA's peak loads. BPA must plan operation of the system to meet both reserves requirements and firm peak loads. Klippstein *et al.*, WP-10-E-BPA-24, at 8. BPA's plans are based on meeting monthly peak loads, not a single peak hourly load. *Id*. The 120-hour peaking capability has served as a good measure of the system capability for meeting both load and reserve needs when allocating costs in the last three rate cases, so it is reasonable to continue to use this allocation mechanism for the WP-10 Wind Balancing Service rate.

Decision

BPA will use the 120-hour peaking capability to allocate system costs to the Wind Balancing Service rate.

Issue 3

Whether the embedded cost pricing methodology should account for secondary generation made from the portion of the system that is used in the allocation of costs for generation inputs, and whether the embedded cost pricing methodology should use average or critical water as an input.

Parties' Positions

NWG points out that BPA's embedded cost methodology ignores secondary energy marketing revenues, and BPA's rates lack a mechanism for crediting such revenues to BPA's non-Federal transmission users. NWG Br., WP-10-B-NG-01, at 21. NWG notes that BPA does provide a credit to the power rates of its public power utility customers for both BPA's secondary energy marketing revenues and the variable and embedded cost components of the Wind Balancing Service rate. *Id*.

Cowlitz points out that BPA's embedded cost methodology uses 1937 water and thus does not account for any nonfirm uses of the Big 10 generation units, but the Big 10 units do produce a substantial amount of secondary energy. Cowlitz Br., WP-10-B-CO-01, at 14.

NWG suggests in its Brief on Exceptions that BPA should revisit its policy regarding crediting the Wind Balancing Service rate with secondary sales revenues, because wind generators are paying a significant portion of the embedded costs of the Big 10 resources. NWG Br. Ex., WP-10-R-NG-01, at 12.

WPAG argues in its Brief on Exceptions that BPA's proposal in the Draft ROD to use average water instead of critical water to determine the 120-hour peaking capability for the embedded cost allocation is inconsistent with section 7(g) of the Northwest Power Act. WPAG Br. Ex., WP-10-R-WG-01, at 19-22. WPAG states that using average water instead of critical water is inconsistent with generally accepted ratemaking principles, and BPA has not justified deviating from generally accepted ratemaking principles in this instance. *Id*. at 20-21. WPAG states that using average water would constitute a major departure from the cost causation principle that will result in an inequitable under-allocation of costs to the Wind Balancing Service. *Id*. at 21. WPAG argues that BPA is replacing cost causation and generally accepted ratemaking principles with a wholly subjective standard of a balanced approach and a fair amount of costs. *Id*. WPAG claims that using average water instead of critical water will result in an unjustified cost shift between customers and urges BPA to continue to uniformly apply critical water in the allocation of costs to the firm uses of the Federal system, whether such uses are related to power services or wind integration. *Id*. at 22.

PPC *et al.* argue in their Brief on Exceptions that it would be an error for BPA to use average water in making the generation inputs embedded cost calculation. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 19-21. PPC *et al.* claim that using critical water is essential to the consistent application of cost causation in allocating costs, and BPA has not demonstrated facts or circumstances that justify changing from the use of critical water. *Id*. at 20. PPC *et al.* argues that by using average water BPA will overstate the peaking capability of the FCRPS and applying that overstated amount to the embedded cost methodology will lower rate levels for certain ancillary services and control area services. PPC *et al.* states that this shift in costs to requirements customers violates the cost causation principle and violates section 7(g) of the Northwest Power Act. *Id*. PPC *et al.* claim that for most other cost allocations regarding power costs BPA uses critical water, and suggest that if BPA were to decide to go to average water instead of critical, it should be addressed from a more holistic perspective. *Id*. at 20-21. PPC *et al.* take issue with BPA's statement in the Draft ROD that using average water instead of critical water would not violate section 7(g) of the Northwest Power Act, because BPA is not crediting transmission rates for secondary sales. PPC *et al.* claims that embedded costs recovered in power rates are allocated based on critical water and power customers receive a credit from secondary sales because power customers bear the risk of underperformance of secondary sales and power customers pay the embedded cost of the entire system, not just the Big 10 hydro units. PPC *et al.* states that it is inappropriate for BPA to attempt to equate using average water to allocate embedded costs to wind generators with the rate treatment afforded power customers. *Id*. at 21.

Snohomish points out in its Brief on Exceptions that the change from critical to average water affects the cost allocation for the Wind Balancing Service rate, Regulating Reserve, and Operating Reserve and that not all of BPA's customers use all of these services. Snohomish Br. Ex., WP-10-R-SN-01, at 9-10. Snohomish states that in the spirit of cost causation, BPA should demonstrate in the Final ROD that there are no cost shifts to their other customers. *Id*. at 10.

BPA Staff's Position

The embedded cost allocation method is designed to allocate costs to only firm uses of the system. Klippstein *et al.*, WP-10-E-BPA-24, at 8-9. No costs of risk mitigation have been included in the generation inputs embedded cost allocation, and the rate adjustment mechanisms for risk mitigation would not apply to these Transmission Services rates, because the risks that contribute to power rates risk mitigation costs and adjustment mechanisms are primarily driven by the uncertainty of secondary sales. *Id*. at 3-4.

Evaluation of Positions

NWG points out that BPA's rates lack a mechanism for crediting revenues from secondary sales to BPA's non-Federal transmission users. NWG Br., WP-10-B-NG-01, at 21. What NWG fails to recognize is that this treatment of secondary revenues is consistent with the responsibility of power requirements customers to pay BPA's power costs. These customers are like the native load of a public utility. Given their responsibility to pay BPA power costs, they enjoy the credits from secondary sales that BPA is able to make.

NWG suggests in its Brief on Exceptions that BPA should revisit its policy regarding crediting the Wind Balancing Service rate with secondary sales revenues, because wind generators are paying a significant portion of the embedded costs of the Big 10 resources. NWG Br. Ex., WP-10-R-NG-01, at 12. Under the Final Proposal wind generators will be paying less than 6 percent of the embedded costs of the Big 10 resources. This is, arguably, not a significant portion of BPA's costs. Section 7(g) of the Northwest Power Act specifically requires that secondary sales revenues be equitably allocated to *power rates*. 16 U.S.C. § 839 e(g) (emphasis added). Wind Balancing Service is not a power rate. Thus, there is no need to revisit the issue of crediting Wind Balancing Service with secondary sales revenues.

Staff's position is consistent with the methodology that was used in the WP-02, WP-07, and WI-09 rate cases. 2002 Final Power Rate Proposal, Wholesale Power Rate Development Study, WP-02-FS-BPA-05, at 71-95; 2007 Final Power Rate Proposal, Wholesale Power Rate Development Study, WP-07-FS-BPA-05, at 92-114. Staff's position is that secondary sales are not a firm use of the system, and under standard ratemaking principles embedded costs are allocated to only firm uses. Staff explained in the Initial Proposal that:

> BPA uses 1937 water conditions for both energy and peak planning because this produces a conservative measure of the system available to serve loads. *See* Loads and Resources Study, WP-10-E-BPA-01. 1937 water conditions have been adopted as the measure of the firm capability of the hydro system. A less-conservative water year increases the risk of BPA being forced into purchasing power to meet peak loads, reserves, or spill requirements. Put simply, using a less-conservative water year could result in over-estimating BPA's load-serving capability on a firm basis, including the ability to provide capacity reserves. It is not prudent utility practice to plan to serve firm load or provide required capacity reserves with energy or capacity that may not be available when needed. The objective of the embedded cost pricing methodology is to allocate system costs to the firm uses of the system. Providing Regulating and Wind Balancing Reserves is a firm use of the system, and therefore costs should be allocated based on BPA's standard measure for firm usage of the system.

Klippstein *et al.*, WP-10-E-BPA-24, at 8-9. It is reasonable to use a conservative approach to planning the system and ensure that BPA can meet both its load and balancing reserve requirements.

In the Draft ROD, BPA reasons that there is no statutory requirement that dictates whether BPA uses critical water, 1937 water, or some other measure for the purpose of allocating costs for generation inputs. Cowlitz's assertion that a fair allocation methodology would include all uses of the Big 10 resources, not only the firm uses, Cowlitz Br., WP-10-B-CO-01, at 14, has some merit.

The Draft ROD goes on to state that if BPA were to use average water instead of critical water to develop the 120-hour peaking capability for purposes of allocating costs to generation inputs, all uses of the system, including secondary sales, would be included. Using average water instead of critical water does not violate section 7(g) of the Northwest Power Act, because BPA is not crediting transmission rates for secondary sales. Instead, BPA is recognizing all uses of its system for purposes of allocating costs for Wind Balancing Service, Regulating Reserve, and Operating Reserve. This change from the Initial Proposal is consistent with the overall principle of cost causation. It also is justified by the need to have a balanced approach to allocating a fair amount of costs to the Wind Balancing Service rate. Using either critical or average water can be justified and supported in this rate proceeding. In future rate proceedings, BPA may want to use critical water for this cost allocation, but for purposes of balancing the interests in this proceeding, average water will be used for determining the 120-hour peaking capability used to allocate cost to generation inputs.

The Draft ROD concludes by stating that Staff also points out that PNRR and other risk mitigation tools do not apply to the cost allocation for generation inputs, because BPA uses 1937 water to allocate embedded cost to this rate, and the revenues assigned to these reserves do not include a credit for secondary sales. Klippstein *et al.*, WP-10-E-BPA-24, at 3-4. This could be read to suggest that if BPA chooses to use average water instead of critical water, PNRR and the CRAC should be applied to the cost allocation for these reserves. However, BPA does not believe this is necessary, because using average water to establish the 120-hour peaking capability is not the same as providing a credit to a transmission rate for secondary power sales.

WPAG, PPC *et al*., and Snohomish all take exception to this modification of the embedded cost methodology. WPAG Br. Ex., WP-10-R-WG-01, at 19-22; PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 19-21; Snohomish Br. Ex., WP-10-R-SN-01, at 9-10. WPAG and PPC *et al.* argue that using average water instead of critical water is not consistent with cost causation or generally accepted ratemaking principles, and that it violates section 7(g) of the Northwest Power Act. WPAG Br. Ex., WP-10-R-WG-01, at 19-22; PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 20-21. BPA does not agree with these assertions.

In the Draft ROD, BPA changes the cost allocation basis from critical water to average water because BPA believes that Cowlitz put forth a compelling argument in its rebuttal testimony and Initial Brief. Cowlitz argues that by using critical water BPA takes no account of the nonfirm uses of the Big 10 units, but in fact the available capacity of the Big 10 units is used to generate substantial amounts of secondary energy. BPA could measure all expected uses of the Big 10 units and spread the fixed costs of those units over all such uses. It is not reasonable for BPA to ignore a major use of its system in allocating embedded cost and simultaneously allocate the change in value of that major use to customers in the variable cost portion of the Wind Balancing Service rate. Skeahan and Essex, WP-10-E-CO-01, at 13-14; Cowlitz Br., WP-10-B-CO-01, at 14.

As discussed in Issues 1 and 2 above, BPA's embedded cost methodology is based on the 120-hour peaking capability of the Big 10 units. It is an average of the highest 120 hours of generation and is intended to provide a measure of all uses, including capacity, energy, and flexibility. Klippstein *et al.*, WP-10-E-BPA-43, at 2. As Cowlitz correctly points out, a significant use of this portion of the system is producing secondary sales, and by using critical water in the Initial Proposal, Staff ignored this use of the Big 10 resources.

The 120-hour peaking capability is determined based on averaging of 14 periods in a year. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 53-54. Regardless of whether average or critical water is used to establish the 120-hour peaking capability, it is simply an allocation methodology that BPA can use to allocate embedded system costs to the various uses of the FCRPS. As discussed in Issue 2 above, BPA is using the 120-hour peaking capability rather than a one-hour instantaneous peak because it is a better measure of the actual operation of the system. Klippstein *et al.*, WP-10-E-BPA-43, at 2. By the same token, BPA agrees with Cowlitz that average water is a better representation of the peaking capability of the hydro system than critical water for purposes of allocating costs to generation inputs.

PPC *et al.* suggest that BPA is attempting to equate average water to crediting wind generators for secondary sales revenues, in violation of 7(g) of the Northwest Power Act. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 21. As stated above in response to NWG's Brief on Exceptions, BPA is not allocating secondary sales revenue credits to the Wind Balancing Service rate. BPA is not attempting to equate the use of average water for allocation purposes to the crediting for secondary sales revenues. Rather, BPA's decision to use average water is based on the recognition that the 120-hour peaking capability should reflect the sustained peaking capability of the Big 10 resources as closely as possible.

WPAG claims that setting the 120-hour peaking capability for purposes of allocating costs to generation inputs for the Wind Balancing Service is the only instance in this rate case in which BPA is proposing to use average water to allocate costs to a firm use of the Federal system. WPAG Br. Ex., WP-10-R-WG-01, at 20. PPC *et al.* claim that for most other cost allocations regarding power costs BPA uses critical water, and suggests that if BPA were to decide to use average water instead of critical, the change should be addressed from a more holistic perspective. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 20-21. WPAG and PPC *et al.* have failed to recognize the context in which this decision is made. In this rate case, BPA uses average water for the determination of Bonneville Average System Costs, WP-10-FS-BPA-05A, Table 2.5.2, the section 7b(3) allocations, *id*,, at Table 2.5.9A, and the determination of the credit to power rates from secondary sales revenues, *id.*, at Table 2.5.3. It has long been established that BPA sets power rates based on average water. See WP-81 ROD, at IX-13. In doing so, BPA allocates costs to power rate based on firm loads served under critical water. But the costs are credited with the additional revenues expected from the generation difference between average and critical water. But Wind Balancing Service does not receive the benefit of those expected revenues for the aforementioned reasons.

WPAG and PPC *et al.* argue that by using average water instead of critical water BPA will over-estimate the amount of Federal system capability available to provide this firm service and under-estimate the cost to Power Services of providing generation inputs. WPAG Br. Ex., WP-10-R-WG-01, at 21; PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 20. If BPA has average water years during the rate period, using average water in the 120-hour peaking capability to allocate embedded generation input costs will not over-estimate the amount of Federal system capability; nor will it under-estimate the costs to Power Services of providing these generation inputs. The amount of embedded costs are not dependent on the amount of water in the system; the embedded costs will be the same whether there is critical or average water.

Despite the WPAG and PPC *et al.* assertions, BPA's decision to use average water instead of critical water for the 120-hour peaking capability calculation is not inconsistent with cost causation or generally accepted ratemaking principles, and it does not violate section 7(g) of the Northwest Power Act. Section 7(g) requires BPA to equitably allocate power costs to power customers in accordance with generally accepted ratemaking principles. 16 U.S.C. § 839e(g). Using average water produces a better reflection of the system's average sustained peaking capability and is therefore consistent with cost causation and generally accepted ratemaking principles for this purpose. The same reasoning does not hold for the allocation of other costs, which are based on energy allocation factors, not capacity allocation factors.

Snohomish points out that the change from critical to average water affects the cost allocation for the Wind Balancing Service rate, Regulating Reserve, and Operating Reserve and that not all of BPA's customers use all of these services. Snohomish Br. Ex., WP-10-R-SN-01, at 9-10. Snohomish is correct that changing from critical to average water will affect all three of these embedded cost allocations, and very few of BPA's customers take all three of these services. But all of BPA's power customers take one or more of these transmission services. Using average water instead of critical water will lower these rates for all customers.

Snohomish states that in the spirit of cost causation, BPA should demonstrate in the Final ROD that there are no cost shifts to their other customers. *Id.* at 10. WPAG and PPC *et al.* argue that the decision to use average water represents an unjustified cost shift to preference customers' power rates. WPAG Br. Ex., WP-10-R-WG-01, at 22; PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 20. If the comparison is simply between the Initial Proposal using critical water and the Final Proposal using average water, arguably there is a cost shift, but this change affects transmission rates paid by all customers and is a reasonable approach to allocating these embedded costs. Because Wind Balancing Service is becoming a significant use of the FCRPS, the Wind Balancing Service rate is increasing proportionally. Consistent with cost causation, wind generators pay for a larger share of the embedded system costs, thus reducing the embedded cost responsibilities of BPA's power customers. In the overall paradigm of BPA's rates, it is meaningless to look at one issue, such as average vs. critical water, and attempt to prove or disprove a cost shift between customer classes. As BPA stated in the Draft ROD, the industry is in a transitional period with unprecedented amounts of wind generation interconnecting to the Federal transmission system, and BPA may propose to use critical water or something completely different in future rate cases.

<u>Decision</u>

BPA will not credit the Wind Balancing Service rate with secondary sales revenues. BPA will use average water to establish the 120-hour peaking capability used in the generation inputs embedded cost pricing methodology.

Issue 4

Whether BPA preference customers pay a capacity charge associated with energy imbalance.

Parties' Positions

NWG claims that BPA's Wind Balancing Service rate discriminates against wind generators, because non-wind generators and load customers are not required to pay a capacity charge associated with generation or energy imbalance. NWG Br., WP-10-B-NG-01, at 30.

NWG argues in its Brief on Exceptions that BPA has not demonstrated that the system costs attributable to imbalance capacity associated with load are recovered in a consistent, equitable, and non-preferential manner as compared to the system cost allocated to the Wind Balancing Service rate. NWG Br. Ex., WP-10-R-NG-01, at 16.

BPA Staff's Position

The issue of non-wind generators not being charged for capacity associated with imbalance is discussed in section 13.3.2.6, Issue 2. There are substantial amounts of reserves required to follow load, and the costs of carrying these reserves are recovered through other existing BPA power rates paid by power customers. Mainzer *et al.*, WP-10-E-BPA-41, at 27.

Evaluation of Positions

The generation inputs embedded cost pricing methodology allocates the revenue requirement for the portion of the system used to provide reserves to the various firm uses of the system. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 55-57. Two of the firm uses of the system identified in the methodology are Regulating Reserve for load and Load Following Reserve for load. *Id*. at 56 and at 65, Table 3.7, lines 2 and 4. The Generation Reserve Forecast calculates the reserve needs for load following and imbalance. *Id*. at 36, Table 2.9. The Following Capacity described in line 4 of Table 3.7 is the combined forecast reserve requirement for load following and load imbalance in the Generation Reserve Forecast. The reserve amounts for load following and load imbalance are added into the cost allocation formula, and a portion of the revenue requirement is attributable to these uses of the system.

Load Regulating Reserve costs are broken out in a separate line item so that these costs can be allocated to Transmission Services for the separate Ancillary Service of Regulation. *Id*. at 57 and Table 3.7, lines 2 and 13. The costs associated with Wind Balancing Service, Regulation, and Operating Reserve Service are assigned to Transmission Services to be recovered from the users of those services. The costs associated with load following and load imbalance are not assigned to Transmission Services. All costs not assigned to Transmission Services are recovered through power rates; thus, the methodology ensures that load customers are paying for their share of the capacity reserves costs.

Despite this explanation, NWG claims that BPA has not demonstrated that the system costs attributable to imbalance capacity associated with load are recovered in a consistent, equitable, and non-preferential manner as compared to the system cost allocated to the Wind Balancing Service rate. NWG Br. Ex., WP-10-R-NG-01, at 16. NWG states that it understands how the energy imbalance and following associated with loads are accounted for in the embedded cost allocation calculation. *Id*. However, NWG appears to claim that BPA must also demonstrate that load customers have a separate line item in their rates to account for the cost of the reserves needed to provide energy imbalance and following. This is not necessary. As stated above, all power costs not allocated to Transmission Services are recovered through power rates. Because BPA has accounted for energy imbalance and following associated with load in the embedded cost allocation calculation, and all costs not allocated to Transmission Services are recovered through power rates, these costs are allocated in a consistent, equitable, and non-preferential manner as compared to the system cost allocated to the Wind Balancing Service rate.

Decision

BPA preference customers pay, as part of their power rates, the capacity costs associated with energy imbalance reserves required by loads, and the reserves associated with providing energy imbalance are properly recognized in the embedded cost pricing methodology.

Issue 5

Whether BPA has supported with substantial evidence its calculation of the components of the embedded and variable costs.

Parties' Positions

MSR claims that Staff's proposal "is long on computer runs and assumptions and short on empirical information and actual examples." MSR Br., WP-10-B-MS-01, at 10. MSR claims that BPA has produced no evidence in support of its position except hypotheticals and simulation models based upon questionable assumptions. *Id*. at 10, 14-15.

NWG states that the variable cost methodology is not based on empirical evidence, *e.g.*, experience or observation, but simply on BPA's internal computer models and untested assumptions. NWG Br., WP-10-B-NG-01, at 21.

PPC *et al.* state that Staff has supported its calculation of the components of the embedded and variable costs with substantial evidence and has also provided clear explanation of how each component recovers discrete system costs. PPC *et al.* Br., WP-10-B-JP11-01, at 30.

BPA Staff's Position

The Initial Proposal documented the basis for the forecast amounts of within-hour balancing reserves and each of the costs that Staff proposes to allocate to the Wind Balancing Service. *See* Generation Inputs Study and Study Documentation, WP-10-E-BPA-08; McManus *et al.*, WP-10-E-BPA-23; Klippstein *et al.*, WP-10-E-BPA-24; and Bermejo and Beale, WP-10-E-BPA-25. Mainzer *et al.*, WP-10-E-BPA-41, at 6.

Evaluation of Positions

MSR asserts that BPA's Wind Balancing Service rate proposal is flawed simply because it is based on computer models and assumptions rather than empirical information and actual examples. MSR Br., WP-10-B-MS-01, at 10. MSR misunderstands the ratesetting process. Setting rates requires forecasting costs and conditions in the future. The amount of wind generation interconnected to BPA's system is quickly expanding and is forecast to continue expanding during the rate period. Mainzer *et al.*, WP-10-E-BPA-22, at 13-14; Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 26-30, Table 2.1. BPA's pricing methodology relies on the Generation Reserve Forecast projection of the amount of capacity reserves that will be needed during the rate period. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 5-47; McManus *et al.*, WP-10-E-BPA-23. This forecast makes substantial use of empirical data for wind generation and load. It is inaccurate to claim that this aspect of BPA's proposal does not use empirical data. *See* section 13.3 above for issues related to the Generation Reserve Forecast.

The pricing methodology uses these reserve amounts as inputs to allocate embedded costs of the portion of the system used to provide the balancing services and to determine the variable costs associated with using the system to provide these reserves. The embedded cost pricing methodology relies on the HYDSIM and HOSS models to develop the 120-hour peaking capability. These computer models are populated with 70 years of historical streamflow data and all the known constraints and limitations on the hydro system. Klippstein *et al.*, WP-10-E-BPA-24, at 8-9. These are the same computer models that are used in BPA's Loads and Resources Study. *Id.*; *see* Loads and Resources Study, WP-10-E-BPA-01, section 2.3.2.1. These models are based on the actual operations of the hydro system, so it is inaccurate to claim that BPA's proposal is not based on empirical data. The results of these models are also used to allocate costs pursuant to sections 7(b) and 7(f) of the Northwest Power Act, to determine the forecast of the secondary revenue credit included in power rates, and to perform the risk analysis used to assess the probability of overall cost recovery.

The variable cost components start with HYDSIM outputs and are supported by an elaborate simulation model that incorporates 70 water years of actual system conditions, applies the total forecast reserve requirement to these water conditions to account for actual system requirements, determines the cost of lost efficiency and energy shift from HLH to LLH, and allocates those costs to the various types of forecast reserve uses. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 67-101; Bermejo and Beale, WP-10-E-BPA-25. This is a computer model, but the inputs to the model are actual measured hydro unit efficiency data provided by the Corps of Engineers and Bureau of Reclamation, actual historical data, and real-world system limitations. Other than the broad assertions described above, no party in the proceeding has raised any specific issues regarding the detail, accuracy, or veracity of the variable cost methodology.

Computer models are a necessary tool for forecasting system operations and supporting the pricing methodology used by BPA. Staff has developed a thorough record of the inputs for these computer models and describes how these inputs were derived from historical data and projections of capacity needs that will increase during the FY 2010-2011 rate period. During the discovery phase of this rate proceeding, the Generation and Reserves Dispatch (GARD) computer model and inputs were posted to BPA's Web site to make them available to parties. MSR's and NWG's broad assertions that BPA's pricing proposal is not based on empirical evidence mischaracterizes the record. MSR suggests that BPA should not adjust its Wind Balancing Service rate until the actual impacts on BPA's system are demonstrated. In other words, MSR would have BPA not charge wind generators for the costs they are imposing on the system until after the fact. MSR suggests at oral argument that BPA's pricing methodologies are simply a proxy:

> [T]here's no place in the testimony, in actual verifiable, ascertainable, quantifiable costs associated with integrating wind. Intuitively we know there must be something as vast as the hydro system is, it's not so vast as to take wind without any kind of limitation. Okay. Put in a marker. All your methodologies, all your simulations are only proxies anyway.

Fisher, Oral Tr. at 99.

As discussed above, BPA's modeling and pricing methodology are not based on proxies, but on historical data and reasonable forecasts of future needs. PPC *et al.* state that BPA has demonstrated that it incurs legitimate and verifiable costs as a result of balancing wind plants in its Balancing Authority Area. Baker *et al.*, WP-10-E-JP6-03, at 22. PPC *et al.* also state that with the extreme increase in wind generation interconnecting to BPA's system, it is essential that BPA provide a reliable cost signal reflecting the actual costs associated with significant wind integration so that the true cost of wind generation is revealed to the marketplace. PPC *et al.* Br., WP-10-B-JP11-01, at 29. It is also important that BPA and all its customers understand the implications of interconnecting this variable generation, so that solutions and alternatives can be developed in a timely fashion to maintain system reliability and foster a rational approach to the development of renewable resources.

Decision

BPA has supported the calculation of the components of the embedded and variable costs with substantial evidence and has also provided clear explanation of how each component recovers discrete system costs.

Issue 6

Whether allocating only variable costs to wind generators would hold BPA's other customers harmless.

Parties' Positions

NWG states that the variable costs represent Staff's estimate of all of its operational costs incurred in providing Wind Balancing Service. NWG Br., WP-10-B-NG-01, at 21. NWG claims that allocating only this amount to the Wind Balancing Service rate should be more than adequate to hold BPA's native load customers harmless for the provision of Wind Balancing Service from the Federal system. *Id*.

PPC *et al.* disagree with NWG. PPC *et al.* state that if the embedded costs of the Big 10 hydro units are borne solely by requirements customers, the Wind Balancing Service rate would not meet the standard of cost causation. PPC *et al.* Br., WP-10-B-JP11-01, at 31. In addition, PPC *et al.* point out that wind generation's use of the FCRPS capacity for balancing needs causes requirements customers purchasing the Slice product to go to market to replace their share of that capability. *Id*.

<u>BPA Staff's Position</u>

Basing the cost allocation for the Wind Balancing Service rate on only the variable costs would not hold BPA's power customers harmless. Mainzer *et al.*, WP-10-E-BPA-41, at 7. Such a rate would not meet the standard of cost causation, because it would have BPA's native load customers pay all the embedded costs of the FCRPS, while the wind generators would be responsible for only some of the incremental costs they impose on the system. The Initial Proposal is based on the cost causation principle that all users of the system should pay their fair share of the system's embedded and variable costs. *Id*.

<u>Evaluation of Positions</u>

In the Initial Proposal, Staff explains why the pricing proposal allocated embedded cost to the Wind Balancing Service rate:

> Provision of within-hour balancing reserves is a required use of the system. We propose to allocate a share of the revenue requirement of the FCRPS to the use of the system that provides *inc* capability for within-hour balancing reserves proportionate to the other required and firm uses of the system. Failure to allocate a share of the revenue requirement of the FCRPS to the use of the system to provide *inc* capability for within-hour balancing reserves would result in other users of the system paying the costs for this use. Allocating embedded costs to these uses is consistent with the ratemaking principle of cost causation.

Mainzer *et al.*, WP-10-E-BPA-22, at 12.

Staff explains the rationale for including variable costs in the allocation to the Wind Balancing Service rate.

> We also propose to allocate to generation inputs certain variable energy costs that the system incurs solely due to the operation of the FCRPS to provide within-hour balancing reserves. Providing this within-hour reserve capability requires PS to change the operation of the FCRPS from an optimal power operation to an operation that 1) is less efficient in converting water to electricity and 2) produces electricity at times at which it is less valuable than during optimal power operation.
>
> A significant amount of these variable costs results from utilizing the capability of the FCRPS to provide *dec*s during light load hours. We propose not to allocate any embedded costs to the service of providing *dec*s. A portion of these variable costs is the result of utilizing the capability of the FCRPS to provide additional

> *inc*s during HLH. All of the allocated variable costs are estimates of actual operational costs that are not included in the revenue requirement.

Id.

NWG asserts that Staff's variable cost pricing methodology represents an estimate of all of the operational costs incurred to provide Wind Balancing Service; thus, this amount should be more than adequate to hold BPA's native load customers harmless. Dragoon, WP-10-E-NG-01, at 26. NWG also recommends that BPA adopt an appropriate cost-based rate for Wind Balancing Services that is no higher than the amount necessary to hold BPA's native load customers harmless for the additional use of the Federal hydro system. Shimshak and Gramlich, WP-10-E-NG-02, at 10.

Staff responds to NWG recommendations, stating:

> NWG's proposal that the rate for Wind Balancing Service be no higher than the amount necessary to hold BPA's native load customers harmless, essentially an incremental rate, would violate the principle of cost causation. NWG quantified this amount as a portion of the variable costs presented in the Initial Proposal. *See* Dragoon, WP-10-E-NG-01, at 28. Such a rate would not meet the standard of cost causation, because it would have BPA's native load customers pay all the embedded costs of the FCRPS, while the wind generators would be responsible for only some of the incremental costs they impose on the system. The Initial Proposal is based on the cost causation principle that all users of the system should pay their fair share of the system's embedded and variable costs.

Mainzer *et al.*, WP-10-E-BPA-41, at 7.

Staff also points out that NWG's recommended pricing of Wind Balancing Service would result in a cost allocation of approximately $10 million annually, which is roughly half the $19 million amount of the settlement of the WI-09 rate without taking into account the increase in the forecast amount of wind and the increased reserves needed due to the inability or failure of the wind fleet to schedule accurately. *Id*. at 24.

NWG's claim that variable costs reflect all of BPA's operating cost and therefore allocating this cost alone to wind generators would hold BPA's power customers harmless is misleading. Staff does not state that the variable cost recovers all of BPA's costs associated with providing Wind Balancing Service. As described above, variable costs are derived from a model that simulates actual operations and measures the operational costs associated with providing reserves. Bermejo and Beale, WP-10-E-BPA-25, at 2. These operating costs are the efficiency losses and cost shift BPA incurs when it uses its system to provide reserves. Operational costs do not include any calculation of the lost flexibility or increased risk that the hydro system will fail to meet non-power constraints, such as those imposed by the Biological Opinion, because BPA is holding out a significant amount of capacity for Wind Balancing Service. Dragoon, WP-10-E-NG-01-AT02, at 10 and 45; Klippstein *et al.*, WP-10-E-BPA-43, at 2. PPC *et al.* are correct in their assertion that BPA's Slice customers must go to market to replace their share of that capability. PPC *et al.* Br., WP-10-B-JP11-01, at 31; Mainzer *et al.*, WP-10-E-BPA-41, at 7.

To maintain a reliable system, BPA must set aside a forecast amount of capacity needed to provide wind balancing reserves. Mainzer *et al.*, WP-10-E-BPA-22, at 2-5. This is a firm use of the system, and BPA has a firm obligation to provide these reserves, unless an interconnected wind generator self-supplies or a third party supplies these reserves. *Id*. Under cost causation principles, the costs of the system are allocated to all firm uses of the system. Mainzer *et al.*, WP-10-E-BPA-41, at 3. If the Wind Balancing Service rate were allocated only the variable costs, arguably the wind generators would be paying for some of the incremental impact that they are having on the system, but they would not be paying any cost for the actual system that is being utilized to provide this service. This approach may be acceptable for a nonfirm use of the system, but it is not consistent cost causation as it pertains to firm uses of the system. The number of wind generators connected to the BPA system is growing and represents a substantial use of firm Federal system capability. Given a forecast of almost 4,000 MW of wind generation by the end of the rate period compared to a peak load of 10,500 MW, wind generation cannot be considered "incremental." As such, the wind generators must share in the costs of the Federal system. Even with the proposed embedded cost and variable cost components, the wind generators are not paying the fully allocated cost that power customers are assessed in power rates. The cost of power includes a number of costs that wind generators are not being asked to pay for; *e.g.*, power purchases, augmentation, the residential exchange, CGS and other Federal system resources, and WNP-1 and -3.

NWG argues that Staff's claim that the variable cost methodology does not recover embedded costs is erroneous. NWG's rationale for this assertion is that if BPA were not providing capacity reserves for wind balancing, the unused capacity would be available for secondary sales, and BPA cannot recover embedded costs in addition to the marketing revenues from secondary sales. NWG Br., WP-10-B-NG-01, at 22. NWG's assertion does not account for two facts: 1) the operating costs recovered through the variable cost methodology are not the only costs imposed on the system by wind generators and 2) secondary sales are a nonfirm use of the system, while providing capacity reserves for the Wind Balancing Service is a firm use of the system and a requirement placed on BPA as the Balancing Authority.

Decision

The variable cost methodology is only one component of BPA's pricing methodology, and allocating only the variable costs to the Wind Balancing Service rate would be inconsistent with the principle of cost causation and would not hold BPA's power customers harmless. BPA will not allocate only the variable costs to the Wind Balancing Service rate.

Issue 7

Whether the Wind Balancing Service rate is charging for the same service as the Generation Imbalance Charge and whether the Generation Imbalance Charge is sufficient to recover BPA's costs.

Parties' Positions

MSR states that any distinction between Generation Imbalance and the Wind Balancing Service rate is confusing on its face, and the charges are duplicative. MSR Br., WP-10-B-MS-01, at 8.

MSR also claims that the Generation Imbalance rate is sufficient to recover all of BPA's costs for supplying reserves to wind generators. *Id*.

MSR requests, in its Brief on Exceptions, further consideration of what makes up the Generation Imbalance rate to determine whether, on an operational basis, it covers all of the costs to the system. MSR Br. Ex., WP-10-R-MS-01, at 3.

NWG asserts that by recovering costs for capacity- and energy-related charges for "deployment costs" under the proposed Wind Balancing Service rate, BPA would continue to recover the energy cost associated with hourly generation imbalances under its Generation Imbalance Service rate. NWG Br., WP-10-B-NG-01, at 29-30. As a result, NWG claims, BPA's provision of imbalance service exceeds the actual costs of correcting imbalances and creates higher prices than under the Commission's pro forma OATT. *Id*.

According to Cowlitz, Generation Imbalance is a charge for energy delivered, whereas the variable costs are primarily the result of a decrease in the amount and value of secondary energy due to configuring the system to provide following reserves. Cowlitz Br., WP-10-B-CO-01, at 12. Thus, Cowlitz claims, "there is no duplication in cost recovery." *Id*.

BPA Staff's Position

Generation Imbalance is an energy charge that recovers the cost of energy from generators when their generation is less than scheduled and pays generators when generation is more than is scheduled. Wellschlager *et al.*, WP-10-E-BPA-27, at 9; Mainzer *et al.*, WP-10-E-BPA-22, at 11. The Wind Balancing Service rate is a capacity rate that recovers the cost of setting aside a significant portion of the FCRPS so that BPA can support the regulation, load following, and imbalance needs of the wind generation customers. Mainzer *et al.*, WP-10-E-BPA-22, at 12. The cost allocation to the Wind Balancing Service rate includes variable costs, which account for the efficiency losses associated with providing reserves. *Id*. There is no duplication of charges, rates, or services, and the Generation Imbalance charge does not recover BPA's costs of supplying capacity reserves to wind generators. Mainzer *et al.*, WP-10-E-BPA-41, at 19-21; Bermejo and Beale, WP-10-E-BPA-44, at 5-6.

Evaluation of Positions

Generation Imbalance is a service that BPA is required to provide for generation in the BPA Balancing Authority Area. Wellschlager *et al.*, WP-10-E-BPA-27, at 9. Generation Imbalance is provided when there is a difference between scheduled and actual energy delivered from a generation resource during a schedule hour. The revenues from Generation Imbalance are positive when BPA provides energy to the customer and negative when BPA absorbs additional energy generated by the customer. Consistent with past rate cases and historical records, BPA is forecasting no revenues associated with energy or generation imbalance, because BPA expects the generation to be over- and under-scheduled an equal amount of time throughout the rate period. Wellschlager *et al.*, WP-10-E-BPA-27, at 9-10; Mainzer *et al.*, WP-10-E-BPA-22, at 11.

MSR claims that any distinction between Generation Imbalance and Wind Balancing Service is confusing on its face and that the Generation Imbalance charge is sufficient to recover BPA's costs, MSR Br., WP-10-B-MS-01, at 8. Staff responds:

> The Generation Imbalance charge does not recover any embedded costs of the system. Additionally, the Generation Imbalance charge compensates BPA for only the energy associated with imbalance. The Generation Imbalance charge does not compensate BPA for the impacts associated with making reserve capability available. These costs are the Stand Ready Costs consisting of Energy Shift, Efficiency Loss, and Base Cycle Loss. Also, the Generation Imbalance Charge does not compensate for the impacts associated with actually delivering reserves.

Mainzer *et al.*, WP-10-E-BPA-41, at 19.

MSR's request for further consideration suggests that the Generation Imbalance rate covers the costs to the system on an operational basis and it is possible that revisions to the Generation Imbalance rate would better capture how BPA's system operates. MSR Br. Ex., WP-10-R-MS-01, at 3. Based on the evidence discussed above, it is clear that the Generation Imbalance rate does not recover all the costs to the system imposed by providing the Wind Balancing Service to wind generators.

NWG's argument appears to be distinct from MSR's confusion between Generation Imbalance and the Wind Balancing Service rate. NWG lists what it believes to be multiple duplicative charges Staff's proposal would impose on wind generators. NWG Br., WP-10-B-NG-01, at 26. The list includes deployment costs; NWG argues that these are an energy charge that is duplicative of Generation Imbalance, and BPA is charging multiple times for the same service. NWG Br., WP-10-B-NG-01, at 29.

Deployment costs are a component of the variable costs that are realized when the FCRPS automatically increases or decreases to balance the system. Bermejo and Beale, WP-10-E-BPA-25, at 8-24; Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 76-86. The deployment costs are distinct from the stand ready costs, which arise from setting up the system to be able to provide the reserves. Both the stand ready costs and the deployment costs measure the efficiency losses of the system when BPA is supplying capacity reserves. *Id.*

NWG claims that deployment costs are duplicative of the Generation Imbalance charge. Dragoon, WP-10-E-NG-01, at 27. Staff explains the difference between deployment costs and Generation Imbalance charges:

> …the energy charges associated with Generation Imbalance are distinct and separate from the charges associated with deploying the FCRPS to meet a reserve need in real time. The distinction between energy used to meet an imbalance and the efficiency losses incurred during reserve deployment may better be understood with an analogy. If one schedules to travel by car a distance of 100 miles, one may optimize efficiency by setting aside enough time to travel at an efficient rate yielding 30 mpg. The fuel consumed is 3.33 gallons. However, if one is asked to make an unplanned trip of the same distance in a shorter amount

> of time, a faster rate of travel is required. Now, over the same 100 miles, one is getting 29 mpg. The fuel consumption is 3.44 gallons. The energy charge associated with Generation Imbalance is analogous to the 3.33 gallons to go the distance if scheduled, and the Deployment Cost is analogous to the +0.11 gallons for additional fuel used when traveling in a less-efficient manner.

Bermejo and Beale, WP-10-E-BPA-44, at 5.

NWG infers that because the wind generators are subject to the Band 2 penalties of the Generation Imbalance charge, they have already paid for the efficiency losses associated with deploying balancing reserves. Generation Imbalance Band 2 penalties are an incentive to encourage accurate scheduling. Mainzer *et al.*, WP-10-E-BPA-41, at 14. Under the Band 2 penalties, if a generator over generates, BPA pays the generator 90 percent of the market price, and if the generator under generates, the generator pays BPA 110 percent of the market price. The 10 percent differential acts as an incentive to foster accurate scheduling and recognizes that the transmission provider will incur additional costs for energy that it did not plan to purchase or provide to the transmission customer.

BPA agrees with Cowlitz's assessment that the Generation Imbalance rate and the Wind Balancing Service rate are not duplicative and there is no overlap between these two rates. Cowlitz Br., WP-10-B-CO-01, at 12. Both are necessary for BPA to recover the costs incurred for providing Ancillary Services and control area services to wind generators. The Wind Balancing Service rate recovers the capacity cost associated with all the reserves provided to wind generators. The deployment cost component of the variable cost that NWG claims is duplicative is a measure of lost efficiency that occurs when reserves are deployed. It does not include any energy costs associated with the actual energy that is provided or received when a wind generator misses its schedule.

<u>Decision</u>

No components of the Wind Balancing Service rate are duplicative of the Generation Imbalance charge, and the Generation Imbalance charge is not sufficient to recover BPA's costs for providing Wind Balancing Service.

<u>Issue 8</u>

Whether variable costs are an opportunity cost as the term is used in the Commission's "And" pricing policy.

<u>Parties' Positions</u>

NWG cites to two Commission cases for the proposition that it is inappropriate to charge both embedded and opportunity costs, and argues that BPA's proposed variable costs are opportunity costs. NWG Br., WP-10-E-NG-01, at 22-27.

Cowlitz agrees with NWG that the variable costs are opportunity costs. Cowlitz Br., WP-10-B-CO-01, at 13-14.

BPA Staff's Position

Variable costs are not opportunity costs, but rather they are the operational costs of providing capacity reserves and are comparable to the cost of fuel consumed by thermal generators when providing capacity reserves. Mainzer *et al.*, WP-10-E-BPA-41, at 22.

Evaluation of Positions

NWG describes the proposed variable cost as primarily the opportunity costs associated with BPA setting aside generating capacity to provide with-in hour reserves. Dragoon, WP-10-E-NG-01, at 24. On the contrary, variable costs are related to lost efficiency through altered timing and placement of energy and through altered unit dispatch. Bermejo and Beale, WP-10-E-BPA-44, at 4. Staff also states that:

> The variable costs identified in the Initial Proposal are not the same as opportunity costs and are analogous to fuel costs of thermal resources. In a thermal system, the fuel costs consumed to spin the generator (such spinning does not produce any energy) would be added to the embedded cost, and these fuel costs would be considered variable, based on the amount of fuel consumed to provide the needed reserves and the efficiency curve of the generator at the time the fuel is consumed. In a hydro system, the fuel is water. Some fuel (water) is consumed by being spilled or a change in the efficiency curve of the generator, and other amounts of fuel (water) are consumed by being shifted in the time it is available for energy production. The cost associated with generator efficiency is the cost of water lost to set up the hydro system to provide reserves. The cost of time shifting water from HLH to light load hours (LLH) is a loss of value not included in our embedded cost calculation. Whereas a thermal plant can measure cost of fuel consumed to provide reserves by the amount of fuel purchased and burned, we have measured the variable hydro fuel cost by comparing the value of the water with and without providing the reserves.

Mainzer *et al.*, WP-10-E-BPA-41, at 22.

Variable costs are a measure of efficiency losses analogous to efficiency losses that a thermal resource would incur when the thermal resource is used to provide reserve capacity. In a thermal system, the fuel costs would be added to the embedded cost, and fuel costs would be considered variable based on the time of day the fuel is consumed, the price of the fuel, and the efficiency curve of the generator at the time the fuel is used; *i.e.*, the total cost of fuel to keep the thermal generator spinning and ready to operate. *Id*.

To distinguish the variable costs from opportunity costs, Staff describes opportunity costs:

> Opportunity costs would be the value BPA received for its highest and best value alternative use of the system. If BPA were not required to provide within-hour balancing reserves, BPA could sell the capacity used for such service to other Balancing Authorities that need within-hour reserves or other capacity products.

Id. at 23.

Staff describes various opportunities to sell capacity in the Pacific Northwest:

> BPA has a number of opportunities to market capacity that it has chosen to forgo due to the need to reserve within-hour balancing capacity. For example, Northwestern Energy has posted several requests for proposals seeking the purchase of within-hour balancing reserves. BPA has been unable to participate in these sales because of the need to provide within-hour balancing reserves as generation inputs.
>
> BPA also has an existing surplus capacity sale to PacifiCorp that expires in 2011 that BPA has been unable to renew, in part due to the need to provide generation inputs. The annual revenue from that 575 MW surplus capacity sale is currently about $60 million.
>
> Additionally, many purchasers have approached BPA seeking the purchase of shaping services to shape the delivery of scheduled amounts of wind generation. BPA is unable to respond to these requests because it has an obligation to provide within-hour balancing reserves to support its BAA.

Id. at 8-9.

NWG cites to the *Ameren* case to support its argument that variable costs are opportunity costs, claiming that the Commission clarifies that the tradeoff—the opportunity cost—of selling capacity is the lost ability to sell energy. NWG Br., WP-10-B-NG-01, at 24, fn. 100, *citing Ameren Energy Mktg. Co.*, 117 FERC ¶ 61,334 (2006). BPA's variable costs appear to fit this definition of opportunity cost, because efficiency losses and the energy shift component of the variable cost methodology are priced at the market price. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 67-101. However, as described above in the evaluation of Issue 6, the variable costs reflect only operational costs and do not recover any costs associated with lost system flexibility or the increased risk to non-power operations of providing a significant amount of capacity reserves. Thus, it is appropriate to consider variable costs analogous to fuel costs and not opportunity costs.

The Commission cases that NWG relies on involve IOU rates and thermal generators. These rates include fuel cost based on the market price forecast for fuel. Because the hydro system fuel is water, the only applicable price forecast is the market price for energy. *Id*.; Mainzer *et al.*, WP-10-E-BPA-41, at 22. It is the use of the market price for energy to value the water consumed in providing reserves that leads to the charge of using opportunity costs. If BPA's system was based on natural gas instead of hydro, there would be no dispute over whether the variable cost of fuel consumed due to efficiency losses should be included in the cost-based rate. The proposed method is analogous to a thermal generator that has a $3/MMBtu fixed gas contract. Suppose the market price for gas is $6/MMBtu and the market price of electricity is $80/MWh. The thermal generator is burning fuel to provide reserves (that is, there is no energy production from the burning of the fuel). The thermal generator should be able to charge $6/MMBtu, not just the $3/MMBtu, as an embedded cost, because its alternative to supply the reserves is to remarket the gas at $6/MMBtu, even though the $6/MMBtu is established based on what could be described as "opportunity cost." In this example, the use of embedded cost "and" opportunity cost would be to use both the embedded cost of the generator, including the $6/MMBtu cost of gas, "and" an $80/MWh in lost power sales cost. Comparing this example to BPA's cost allocation for the Wind Balancing Service rate, the embedded and variable costs are components of a cost-based rate, while the opportunity cost would be the cost at which BPA could have sold its capacity if it were not being used to provide Wind Balancing Service. Staff's description of such opportunity cost above (*i.e.*, surplus capacity sale to PacifiCorp) is comparable to the $80/MWh lost power sale in the example.

NWG contrasts the proposed variable cost against the WP-07 regulating reserve cost allocation, pointing out that, instead of variable cost, the WP-07 rate had an AGC adder. Wholesale Power Rate Development Study, WP-07-FS-BPA-05, at 96-99. The AGC adder had two components: a loss of efficiency due to the hydro units being required to operate less efficiently, and increased O&M cost. NWG Br., WP-10-B-NG-01, at 22, fn. 84. NWG claims that while the AGC adder had only two components, the variable cost methodology contains seven components. *Id*. NWG's number is misleading, because six of the seven components in the variable cost methodology are efficiency losses derived from the GARD model. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 76-86. The differences between the WP-07 AGC adder and the WP-10 variable costs are that the variable cost does not include an additional maintenance component; however, it does include a component for measuring the energy shift from HLH to LLH. In addition, the calculation of the efficiency losses is done with the GARD model, which provides more detail and is arguably a significant improvement in the substantive evidence needed to support this cost allocation.

Decision

Variable costs are operating costs that measure the efficiency losses and energy shift of providing capacity reserves. These costs are analogous to fuel costs of thermal generators, and they are not opportunity costs as the term is used in the Commission's "And" pricing policy.

Issue 9

Whether BPA's proposed Wind Balancing Service rate violates the Commission's "And" pricing policy.

Parties' Positions

NWG claims that because BPA's proposal includes both embedded and opportunity costs, and it is not capped at the higher of embedded or opportunity costs, it violates the Commission's "And" pricing policy. NWG Br., WP-10-B-NG-01, at 24-27.

Cowlitz states that the variable costs are akin to opportunity costs and that recovering both would violate the "And" pricing policy. However, Cowlitz points out that the embedded cost methodology is based on only *inc* reserves, and if the methodology were modified as NWG suggests, BPA would be providing *dec* reserves at no cost. Cowlitz Br., WP-10-B-CO-01, at 13. Cowlitz recommends using the embedded cost method to allocate cost for *inc* reserves and the variable cost method to allocate cost for *dec* reserves. *Id*. at 13-14.

PPC *et al.* argue in their Brief on Exceptions that BPA's proposal in the Draft ROD not to include the energy shift cost associated with providing *inc* reserves is arbitrary and capricious and violates BPA's stated cost causation principles, because the costs are shifted to requirements customers in violation of section 7(g) of the Northwest Power Act. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 22-23. PPC *et al.* state that BPA fails to recognize that under the Tiered Rate Methodology BPA will rely heavily on basing certain charges on the difference between HLH and LLH pricing, so using this pricing for the Wind Balancing Service rate is not unique. *Id.* at 23.

<u>BPA Staff's Position</u>

As discussed above, variable costs are not opportunity costs. Mainzer *et al.*, WP-10-E-BPA-41, at 10 and 22-23. The Initial Proposal cost allocation of embedded and variable costs for generation inputs does not constitutes "And" pricing, as defined and used by the Commission. *Id.* at 10.

<u>Evaluation of Positions</u>

The Commission's review of BPA's rates is limited to whether or not the rates will recover BPA's costs and, in the case of transmission rates, whether the costs have been equitably allocated between Federal and non-Federal customers. Northwest Power Act, 16 USC § 839e(a)(2). Even if the Commission were to agree with NWG's "And" pricing argument, it would not mean that BPA's rates are in violation of the equitable allocation standard, because the Wind Balancing Service rate will be applied equally to both Federal and non-Federal customers.

NWG provides a good description of the Commission "And" pricing policy and argues that the pricing methodology for the Wind Balancing Service rate in the Initial Proposal violates this policy. NWG Br., WP-10-B-NG-01, at 24-27. The "And" pricing issue in this proceeding turns on whether or not the variable costs are seen as opportunity costs or incremental fuel costs. As discussed above in Issue 8, BPA does not believe that the variable costs are opportunity costs as used in the Commission's policy, and the pricing proposal does not violate the "And" pricing policy.

Cowlitz agrees with NWG that the variable costs are opportunity costs, but Cowlitz also recognizes the need to recover costs for both *inc* and *dec* reserves and that allocating costs based only on the proposed embedded cost methodology would recover only costs associated with *inc* reserves. Cowlitz Br., WP-10-B-CO-01, at 13; Skeahan and Essex, WP-10-E-CO-01, at 15-17. As such, Cowlitz's proposal of charging for *inc* reserves based on the embedded cost methodology and *dec* reserves using the variable cost methodology deserves some consideration. *Id.* at 13-14.

In response to NWG's assertion that charging embedded and variable costs violates the "And" pricing policy, Staff discusses various alternatives in rebuttal testimony:

> The embedded cost methodology in the Initial Proposal used only the forecast of *inc* reserve needed to support wind integration, and if the generation inputs cost allocation included only the embedded cost method, there would be no cost recovery associated with providing *dec* reserves. We could increase the amount

> of reserves allocated to the embedded costs to the combined total of *inc* and *dec* reserves. This would result in an embedded cost allocation based on 2,534 MW of wind-balancing reserves, as compared to the 1,045 MW of *inc* reserves that was used in the Initial Proposal.
>
> …charging embedded cost based on both the *inc* and *dec* reserve forecast would significantly increase the Wind Balancing Service rate from its level in the Initial Proposal. We believe that the Initial Proposal strikes a good balance by allocating only the embedded cost based on the *inc* reserve amount and adding the variable cost component to account for the fuel costs associated with both *inc* and *dec* reserves. Arguably, *dec* reserves put more strain on the system and are harder to produce or procure than *inc* reserves. An alternative that could be considered is allocating embedded costs on the higher of the amount of *inc* or *dec* within-hour balancing reserves. Under the 2-hour persistence forecast accuracy used to estimate reserves in the Initial Proposal, the amount of within-hour reserves used to allocate embedded costs would increase from 1,045 MW to 1,489 MW.

Mainzer *et al.*, WP-10-E-BPA-41, at 25-26.

Basing the cost allocation for the Wind Balancing Service rate on only the embedded cost is problematic. As Cowlitz points out, if BPA agrees with NWG and bases its embedded cost methodology only on the forecast amount of *inc* reserves, BPA would be assigning no costs to *dec* reserves. Cowlitz Br., WP-10-B-CO-01, at 13. *Dec* reserves put more of a strain on the system and are harder to produce and procure than *inc* reserves. Mainzer *et al.*, WP-10-E-BPA-41, at 26. It is important that this rate recognize that there are costs associated with *dec* reserves, because in the future BPA may need to go to the market to procure *dec* reserve capability. *See* Dragoon, WP-10-E-NG-01-AT02, at 8, 17, 21, 31. The other alternatives Staff suggests, charging embedded costs on the combination of *inc* and *dec* reserves or the higher of *inc* and *dec* reserves, would result in a higher Wind Balancing Service rate and do not appear to be the correct approach to allocating these costs.

There are other alternatives for modifying the variable cost proposal to recognize that some of the proposed variable costs are measured by reference to opportunity costs. BPA could voluntarily comply with NWG's interpretation of the Commission's "And" pricing policy by either modifying the variable cost to remove energy shift cost associated with *inc* reserves or by allocating embedded costs for *inc* reserves and variable costs for *dec* reserves. Mainzer *et al.*, WP-10-E-BPA-41, at 25. Staff does not support the option advanced by Cowlitz, charging embedded cost for *inc* reserves and variable cost for *dec* reserves, because variable costs are not opportunity costs. *Id.* at 27. In addition to the alternative advanced by Cowlitz, Staff posits an alternative that would remove the energy shift costs associated with *inc* reserves from the variable cost methodology. Staff reasons that:

> The Deployment Costs are efficiency losses that occur when BPA provides reserves and represent actual losses of water associated with deploying reserves. The Stand Ready Costs are divided into three components: Energy Shift, Efficiency Loss, and Base Cycle Loss. Both the Efficiency Loss and the Base Cycle Loss are efficiency losses measured by the water that is actually lost when the system is set up to stand ready to supply the reserves. The only category of

> variable costs that could possibly fit NWG's premise of selling the same MW of generating capacity twice is the *inc* portion of the Energy Shift component of the Stand Ready Costs.

Mainzer *et al.*, WP-10-E-BPA-41, at 27; *see* Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 76-86.

Ultimately, Staff does not recommend this option because Staff does not agree that variable costs are opportunity costs, but Staff recognizes that this option and the option suggested by Cowlitz should be considered. Mainzer *et al.*, WP-10-E-BPA-41, at 28.

The *inc* reserve Energy Shift component of the variable cost is described as:

> Energy shift costs may be incurred while providing *inc* capability in circumstances where the ability to shape energy into the more valuable HLH period is limited due to lack of turbine availability. Turbine capability that could otherwise have been generating power for sale during the HLH period instead is rendered unavailable because turbines must be kept standing ready in case they are called on to increase generation for *inc* reserves. To the extent that providing the required *inc* capability is a contributing factor in limiting turbine availability, energy shifts into LLH.

Bermejo and Beale, WP-10-E-BPA-25, at 9.

The GARD model calculates the *inc* reserve Energy Shift cost by measuring the amount of energy shifted from HLH to LLH and then multiplying the difference between the market price forecast HLH price and the LLH price. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 76-86. BPA does not believe this component represents an opportunity cost. However, since it is based on the difference between the HLH and LLH pricing, and this component is different from BPA's pricing in past rate proposals, BPA will remove the *inc* reserve Energy Shift costs from the variable cost pricing proposal in the Final Proposal. BPA will make this adjustment in this rate proceeding, but BPA may reevaluate the need for this cost component in future rate proceedings. Consistent with Cowlitz's suggestion, BPA will include all of the forecast variable cost associated with *dec* reserves in the Final Proposal. The other six components of the variable cost associated with *inc* reserves are all efficiency losses that measure the additional water used by the system when BPA is either standing ready to deploy reserves or additional water that is used when the reserves are deployed. *Id*. at 76-86. These costs are analogous to additional fuel used by a thermal generator that is providing the same type of service, and as NWG points out, BPA has included efficiency losses in the cost allocation in past rate cases. NWG Br., WP-10-B-NG-01, at 22, fn. 84.

PPC *et al.* claim that BPA's decision not to include the *inc* reserve Energy Shift cost component in the variable cost calculation is unsupported in the record. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 22. PPC *et al.* state that BPA aptly defends its prior proposal for charging wind generators variable costs as recovering legitimate and identifiable costs. *Id*. PPC *et al.* state that BPA concludes that it has supported the calculation of the components of the embedded and variable costs with substantial evidence and has also provided evidence of how each component recovers discrete system costs. *Id*. PPC *et al.* also state that BPA further concludes that the costs of providing balancing reserves that are recognized in the variable costs are not duplicative of the Generation Imbalance charge, that they are not opportunity costs, and that recovery of the embedded and variable costs is not "And" pricing. *Id.* PPC *et al.* conclude that BPA's decision not to include the *inc* reserve Energy Shift cost component in the variable cost calculation is arbitrary and capricious, because these costs are supported by substantial evidence. *Id.*

BPA agrees with PPC *et al.* that BPA has justified charging wind generators variable costs as recovering legitimate and identifiable costs and that the calculations of the components of the embedded and variable costs are supported with substantial evidence, including evidence of how each component recovers discrete system costs. BPA agrees that the costs of providing balancing reserves that are recognized in the variable costs are not duplicative of the Generation Imbalance charge, that they are not opportunity costs, and that recovery of the embedded and variable costs is not "And" pricing.

BPA disagrees with the PPC *et al.* assertion that the decision not to include the *inc* reserve Energy Shift cost component in the variable cost calculation is unsupported in the record. As discussed above, Staff described this as an option that should be considered. Mainzer *et al.*, WP-10-E-BPA-41, at 28. Based on the "And" pricing arguments raised by NWG, NWG Br., WP-10-B-NG-01, at 24-27, and the suggestion by Cowlitz that BPA should allocate embedded cost based on *inc* reserves and variable cost based on *dec* reserves, Cowlitz Br., WP-10-B-CO-01, at 13-14, BPA has decided that not including the *inc* reserve Energy Shift cost component in the variable cost calculation is appropriate. As Staff stated, "the only category of variable costs that could possibly fit NWG's premise of selling the same MW of generating capacity twice is the *inc* portion of the Energy Shift component of the Stand Ready Costs." Mainzer *et al.*, WP-10-E-BPA-41, at 27. This decision is consistent with Cowlitz's recommendation, because all the variable cost associated with *dec* reserves is still included, but it also includes the efficiency losses associated with *inc* reserves. As described above, BPA has included efficiency losses in the AGC adder in past rate cases, but in the past the Energy Shift component has not been included.

PPC *et al.* claim that not including the Energy Shift cost associated with providing *inc* reserves is arbitrary and capricious and violates BPA's stated cost causation principles, because the costs are shifted to requirements customers in violation of section 7(g) of the Northwest Power Act. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 22-23. BPA does not agree that this decision is arbitrary and capricious. As stated above, the decision not to include this new component of *inc* Energy Shift cost is supported in the record, and it is a reasonable adjustment to the variable cost pricing methodology.

In addition, this decision does not violate cost causation principles by shifting costs to requirements customers in violation of section 7(g) of the Northwest Power Act. The Wind Balancing Service rate is allocated an appropriate share of embedded costs based on the *inc* reserve forecast, all variable cost associated with *dec* reserves, and the six efficiency loss components associated with *inc* reserves. Not including this one component, which has some potential of being cast as a double recovery and in violation of the "And" pricing policy, is prudent and reasonable. Cost causation principles do not dictate that every possible cost associated with a system use should be allocated to a system use. For that matter, the equitable allocation standard of section 7(g) of the Northwest Power Act does not require that BPA allocate costs to Transmission Services that are not clearly justified. Parties and Staff raise legitimate issues that bring the inclusion of the *inc* Energy Shift component of the variable cost allocation into question. Therefore, it is reasonable not to include these costs in the allocation for the Wind Balancing Service rate.

PPC *et al.* also assert that BPA fails to recognize that under the Tiered Rate Methodology BPA will rely heavily on basing certain charges on the difference between HLH and LLH pricing, so using this pricing for the Wind Balancing Service rate is not unique. *Id*. at 23. The TRM rates will not be effective until after the FY 2010-2011 rate period, however, and a host of details regarding these rate designs are yet to be developed. In the next rate proceeding, TRM rates will be considered for purposes of establishing the generation inputs cost allocations.

Decision

BPA is not subject to the Commission's "And" pricing policy. In any case, recovering both embedded and variable costs in the Wind Balancing Service rate does not violate the "And" pricing policy. However, in the interest of ensuring that BPA's Wind Balancing Service rate is not overstated, BPA will modify the variable costs in the final studies to include only the variable costs for dec reserves and the efficiency losses for inc reserves. The energy shift component of the variable cost methodology for inc reserves will be removed from this rate, but may be reconsidered in future rates.

Issue 10

Whether BPA is proposing to charge wind generators multiple times for each megawatthour of imbalance energy.

Parties' Positions

NWG asserts that BPA is proposing to charge wind generators multiple times for each megawatthour of imbalance energy. NWG Br., WP-10-B-NG-01, at 26.

PPC *et al.* state that BPA has supported its calculation of the components of the embedded and variable costs with substantial evidence and has also provided a clear explanation of how each component recovers discrete system costs. PPC *et al.* Br., WP-10-B-JP11-01, at 30.

BPA Staff's Position

The charges that NWG describes are not duplicative. Mainzer *et al.*, WP-10-E-BPA-41, at 21. Staff's proposed Wind Balancing Service rate is a capacity charge that includes embedded cost and variable cost components. Mainzer *et al.*, WP-10-E-BPA-41, at 12. The only energy charge is Generation Imbalance, and that charge is an after-the-fact reconciliation of the difference between schedule and generation. *Id*. at 11.

Evaluation of Positions

As part of its "And" pricing argument, NWG claims that under the Initial Proposal, wind generators will be charged a capacity charge, two energy charges, and an opportunity-cost charge for each megawatthour of imbalance energy. NWG Br., WP-10-B-NG-01, at 26. This is a mischaracterization of the rate proposal. NWG characterizes the embedded cost component of the Wind Balancing Service cost allocation as a capacity charge, the deployment cost component of the variable cost as an energy charge, Generation Imbalance charge as an energy charge, and the variable costs as an opportunity cost charge. *Id*.

As discussed in Issue 7 above, the deployment cost component of the variable costs is not a separate energy charge. Deployment costs are the lost efficiency that is realized when the hydro units are adjusted to respond to a reserve deployment. Bermejo and Beale, WP-10-E-BPA-25, at 17. For the reasons described above, these efficiency losses are appropriate to include in the Wind Balancing Service cost allocation. The second energy charge that NWG lists is the standard Generation Imbalance charge that is used to settle imbalances after the fact. It is important to remember that the Generation Imbalance charge is both a charge and a credit that settles any differences between schedule and actual generation; this energy charge or credit is appropriate and does not represent any change from the current rate schedule. Mainzer *et al.*, WP-10-E-BPA-41, at 14-15. Finally, NWG asserts that all the variable costs are opportunity costs. NWG Br., WP-10-B-NG-01, at 26. As discussed in Issues 8 and 9 above, the variable costs are not opportunity costs but recover the efficiency losses associated with providing capacity reserve.

PPC *et al.* state that Staff has supported its calculation of the components of the embedded and variable costs with substantial evidence and has also provided a clear explanation of how each component recovers discrete system costs. PPC *et al.* Br., WP-10-B-JP11-01, at 30. NWG's assertion regarding multiple charges is unfounded. BPA's proposal will charge wind generators the Wind Balancing Service rate, which represents an appropriate allocation of the embedded cost of the system associated with the wind generators' use of the system and some of the variable costs associated with the efficiency losses BPA incurs from providing capacity reserves for the Wind Balancing Service rate. Wind generators will continue to pay or get paid under the Generation Imbalance charge based on the actual energy deviation between the schedule and the wind generators' performance during the hour.

Decision

The inclusion of variable costs in the Wind Balancing Service rate does not result in wind generators paying multiple times for the same megawatthours of imbalance.

Issue 11

Whether BPA can unbundle the regulation, following, and imbalance components of the Wind Balancing Service cost allocation to assign costs to each.

Parties' Positions

Iberdrola requests that BPA include a rate mechanism for wind generators to self-provide one or more of the components of the Wind Balancing Service rate. Iberdrola Br., WP-10-B-IR-01, at 4, 18. Iberdrola supports BPA's proposal in the Draft ROD to unbundle the components of the Wind Balancing Service rate. Iberdrola Br. Ex., WP-10-R-IR-01, at 10.

NWG advocates unbundling the Wind Balancing Service rate into its three components—regulation, following, and imbalance—to allow wind generators to self-supply one or more of the components. NWG Br., WP-10-B-NG-01, at 40.

MSR supports BPA's proposal in the Draft ROD to unbundle the components of the Wind Balancing Service rate. MSR Br. Ex., WP-10-R-MS-01, at 3-4.

PPC *et al.* support BPA's proposal in the Draft ROD to unbundle the components of the Wind Balancing Service rate. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 23-24.

BPA Staff's Position

Iberdrola and NWG raised the unbundling issue for the first time in their Initial Briefs, so Staff have not responded to this issue in the record.

Evaluation of Positions

BPA believes that self-supply of capacity reserves needs to be a viable option for wind generators interconnected to BPA's system. Unbundling the components of the Wind Balancing Service rate will allow Transmission Services to provide a separate rate for each component and will ensure that rate design is not a barrier to self-supply options during the rate period. Power Services can break out the cost allocation so that Transmission Services can price the various components of the Wind Balancing Service rate. The megawatts associated with Regulating Reserves, Load Following Reserves, and Imbalance Reserves are broken out separately in the Generation Reserve Forecast. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 45-47, Tables 2.11-2.13. For the Final Proposal, Power Services will allocate embedded and variable costs to each of the components and provide these as inputs to Transmission Services for appropriate rate design. For a further discussion of how Transmission Services will address this issue, *see* Chapter 20 of this ROD.

Decision

BPA will unbundle the components of the Wind Balancing Service cost allocation.

13.5 Operating Reserve Cost Allocation

13.5.1 Introduction

Operating Reserve is the reserve that Transmission Services provides under Schedules 5 and 6 of the OATT. Reserves used for Schedules 5 and 6 of the OATT are sometimes referred to as Contingency Reserves, but for purposes of allocating cost in this WP-10 rate proceeding, they are referred to as Operating Reserve. Operating Reserve is an amount of spinning reserve and non-spinning (Supplemental) reserve, of which at least half must be spinning reserve.

The cost allocation for Operating Reserve uses the same pricing methodology as Regulating Reserve and Wind Balancing Reserve. The one difference is that the Operating Reserve revenue requirement includes more than the costs of the Big 10 projects, because non-spinning Operating Reserve is available from additional hydro projects. Transmission Services forecasts the amount of Operating Reserve the FCRPS will need to provide using historical data and forecast load growth. Power Services uses the projected Operating Reserve as an input to the embedded cost methodology to determine a unit price for Operating Reserve and forecast the revenues from Transmission Services resulting from this cost allocation. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, section 5. There is also a variable cost component for spinning Operating Reserve that is calculated as part of the variable cost pricing methodology and added to the spinning Operating Reserve unit cost and the revenue forecast. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, section 4.

13.5.2 Changes and Adjustments to the Initial Proposal Operating Reserve Cost Allocation

Because the Operating Reserve pricing methodology is essentially the same as the pricing methodology for Regulating Reserve and Wind Balancing Reserve, the changes to the pricing methodology discussed above in section 13.4 also will be applied to the Operating Reserve pricing and cost allocation in the Final Proposal. Other factors that will effect changes from the Initial Proposal include reductions in the revenue requirement used to allocate the embedded cost for Operating Reserve; the new market price forecast used in the risk analysis lowers the variable cost component of spinning Operating Reserve.

In addition, the Initial Proposal describes a change to the Operating Reserve standard that WECC has proposed and that is currently pending at the Commission. Bolden *et al.*, WP-10-E-BPA-26, at 10. This new methodology would lower the reserve requirements forecast by Transmission Services. *Id.* at 11. Staff states that it uses the existing WECC standard for purposes of the Initial Proposal but would change to the new standard if it is approved by the Commission prior to the completion of the WP-10 Final ROD. *Id.* at 10. Staff also stated that if the Commission did not act on the new standard in time, the Administrator will make a determination of the appropriate standard to use for forecasting the cost allocation. *Id.* at 11. This decision will not affect the actual implementation date of the new standard, because Transmission Services will apply the new standard on the effective date set by the Commission.

The Commission has not yet acted on the new WECC standard for Operating Reserve, and BPA does not expect the Commission to approve the new standard by the beginning of the rate period. BPA does expect the Commission to approve the new standard at some point during the rate period, however. Accordingly, for purposes of establishing the unit cost and forecasting revenues, BPA will assume that the new WECC Operating Reserve standard will go into effect six months after the beginning of the FY 2010-2011 rate period. Thus, the unit price and forecast revenue will be based on the existing WECC standard for six months and the new WECC standard for 18 months.

13.5.3 Issues

No issues were raised regarding the Operating Reserve cost allocation.

13.6 Other Inter-business Line Cost Allocations

13.6.1 Introduction

In addition to the generation input cost allocations described above, Power Services allocates cost to Transmission Services for synchronous condensing operations, generation dropping, energy and generation imbalance, redispatch, segmentation of Corps of Engineers and Bureau of Reclamation transmission facilities, and station service. Each of these is described below.

13.6.2 Synchronous Condensing

Transmission Services uses certain generation units at specific projects as synchronous condensers when needed to maintain reliability on the transmission system. A synchronous condenser is essentially a motor with an excitation system that enables it to provide voltage control to the BPA transmission system. Synchronous condensers dynamically absorb or supply reactive power in real time to actively manage voltage on the transmission system. While providing this service, the units consume energy, which is provided by other FCRPS generators. The cost of the energy provided is allocated to Transmission Services at the market price forecast used in the risk analysis. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, section 6. The investment in plant modifications at the John Day and The Dalles projects necessary to provide synchronous condensing also is allocated to Transmission Services for this service.

Since BPA submitted its Initial Proposal, three things have changed that affected the estimated cost for this service. First, the market price forecast used in the risk analysis has changed, thus lowering the cost allocation for synchronous condensing. Second, since the Initial Proposal BPA has completed a study and subsequent field tests on the voltage support required from the Willamette Valley projects. Wellschlager *et al.*, WP-10-E-BPA-27, at 4. Staff explained that it was still analyzing the forecast number of condensing hours for voltage control for the Willamette River projects, which may result in fewer forecast condensing hours in the Final Proposal. Preliminary studies by Transmission Services operations staff indicate that the future need for condensing for voltage support at the Willamette River projects appears to be less than historical condensing operations would suggest. *Id.* at 5. Those studies and subsequent field testing are now complete and indicate that voltage support from the Willamette Valley projects is needed during only certain system conditions, in which case a Transmission Services dispatcher may temporarily request the operation of one or more units in condense mode. As such conditions are not expected to occur on a frequent basis, the energy consumption for synchronous condensing at these plants is forecast to be zero. Third, the forecast of investment in plant modification is lower than the forecast in the Initial Proposal. The lower market price forecast for the risk analysis, the lower forecast of condensing hours needed for voltage control for the Willamette River projects, and the lower plant modification forecast will be reflected in the Final Proposal.

13.6.3 Generation Dropping

Generation dropping is provided to Transmission Services as part of one of the Remedial Action Schemes (RAS) used to maximize transmission capacity. The RAS scheme is based on having the ability to instantaneously drop a large increment of generation. Power Services allocated the cost of generation dropping by first forecasting the number of times the RAS will be deployed. Then Power Services calculated the added wear and tear caused by the instantaneous dropping and the lost revenue resulting from an increase in forced outages for repairs caused by the instantaneous dropping. The forecast cost allocation for generation dropping will be modified to reflect the lower market price forecast used in the risk analysis, which is used to calculate the lost revenue component of the generation dropping cost allocation.

13.6.4 Energy and Generation Imbalance

Energy imbalance is provided when there is a difference between scheduled and actual energy delivered to a load in the BPA Balancing Authority Area during a schedule hour. Generation imbalance is provided when there is a difference between scheduled and actual energy delivered from a generation resource in the BPA Balancing Authority Area during a schedule hour. Both are Commission-approved services that BPA is required to provide.

Historically, the net annual amount of imbalance has been small. The Initial Proposal forecast zero dollars in the revenue forecast for this service based on the difficulty of predicting what the net transfer may be. The forecast will remain the same for the Final Proposal.

13.6.5 Redispatch

As part of congestion management efforts, Transmission Services may request the redispatch of Federal resources from Power Services under Attachment M of the OATT. Redispatch under Attachment M generally results in the incrementing or decrementing of Federal resources. Attachment M provides for three levels of redispatch: Discretionary Redispatch, Network Redispatch, and Emergency Redispatch. The forecast of costs and revenues associated with redispatch will not be changed for the Final Proposal.

13.6.6 Segmentation of COE and Reclamation Transmission Facilities

The investment in the Corps of Engineers and Bureau of Reclamation transmission facilities is divided into three segments: Generation Integration (GI), Integrated Network, and Utility

Delivery. The investment associated with the Corps and Reclamation transmission facilities is allocated to either Power Services or Transmission Services based on which segment a particular transmission facility is classified under. The investment associated with the GI segment is allocated to Power, and the investment associated with the Integrated Network and Utility Delivery segments is allocated to Transmission. The forecast of costs and revenues associated with segmentation of Corps and Reclamation transmission facilities has slightly decreased from the Initial Proposal because of adjustments to the Power Services revenue requirement.

13.6.7 Station Service

Station service refers to real power that Transmission Services takes directly off the BPA power system for use at substations and other non-electric plant, such as facilities located on the Ross Complex and the Big Eddy/Celilo Complex. BPA forecasts the amount of power that will be consumed for station service and prices that power at the market price forecast for the risk analysis. The forecast cost will be adjusted to reflect the lower market price forecast used in the risk analysis.

13.6.8 Issues

No issues were raised regarding these other inter-business line cost allocations.

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14.0 RATE DESIGN

14.1 Introduction

The purpose of rate design is to define the methods and criteria used for collecting the revenue requirement from power sales. The methods and criteria are generally guided by cost causation and price signals that are aimed to encourage responses consistent with BPA's agency strategy map. The rate design referred to in this section is implemented after the three main steps conducted by the Rate Analysis Model (RAM): 1) the cost of service analysis, which allocates the costs associated with the three resource pools and non-resource costs; 2) the rate directives, in which the RAM carries out a series of statutory adjustments as directed by the Northwest Power Act; and 3) the Slice Separation step, which separates the PF Slice product revenues, revenue credits, and firm loads from the overall PF Preference rate pool. The result of the rate design is the rate components for energy, demand, and load variance.

The subsections that follow review the issues that were raised by rate case parties in their briefs concerning the rate design used in the development of BPA's FY 2010-2011 power rates.

14.2 Stepped Rates

This issue, while referring to "stepped rates" throughout, is directed at only the PF Preference rate. The term "stepped rates" is used as shorthand for developing a PF Preference rate schedule that applies to FY 2010 and a separate schedule that applies to FY 2011, rather than one rate schedule applying to both years. The discussion herein is not meant to imply that any party, including BPA, is considering stepping any rate other than the PF Preference rate.

Issue 1

Whether BPA should include stepped rates in its FY 2010-2011 wholesale power rates.

Parties' Positions

Cowlitz PUD states that BPA should adopt separate stepped rates for FY 2010 and FY 2011 to help utilities keep their rates low. Cowlitz Br., WP-10-B-CO-01, at 1. Cowlitz states that there are two major reasons that support adopting stepped rates: one is that BPA's forecast costs are materially higher in FY 2011 than in FY 2010, and the second is that the current severe recession makes it highly imprudent to force customers, and thus their end-use consumers, to begin paying the higher FY 2011 costs in FY 2010. *Id*. at 2. In its Brief on Exceptions, Cowlitz states that it is pleased that BPA will offer a stepped payment option under the Flexible PF Rate Option. Cowlitz Br. Ex., WP-10-R-CO-01, at 1.

ICNU states that stepped rates are appropriate to eliminate any rate increase in FY 2010. ICNU Br., WP-10-B-IN-01, at 7. ICNU contends that stepped rates make sense because there is a significant difference between BPA's forecast costs in FY 2010 and FY 2011, and a stepped rate will not harm any utilities. *Id*. at 8-9.

The City of Seattle states that current economic conditions warrant adopting stepped rates for FY 2010-2011 and that stepped rates better reflect BPA's actual revenue requirements in FY 2010 and FY 2011. Seattle Br., WP-10-B-SE-01, at 1-2.

WPAG advocates eliminating any PF rate increase for the FY 2010-2011 rate period. WPAG Br., WP-10-B-WG-01, at 2, 6. WPAG states that BPA should implement a stepped rate so it can offer the lowest possible rate in the first year of the rate period. WPAG Br., WP-10-B-WG-01, at 10. WPAG argues that such an approach makes sense, because the revenue requirement for the first year of the rate period is forecast to be considerably lower than the revenue requirement for the second year. *Id*. In its Brief on Exceptions, WPAG noted that it was a constructive solution for BPA to offer a stepped payment option under the Flexible PF Rate Option. WPAG Br. Ex., WP-10-R-WG-01 at 4.

NRU states that stepped rates are not warranted. NRU Br., WP-10-B-NR-01, at 5. NRU argues that stepped rates should not be developed unless the rate increase may greatly exceed 5 percent in FY 2010 and 2011 when compared with FY 2009. *Id*. at 6. NRU supports the use of the Flexible PF Rate Option BPA suggested in the Draft ROD. NRU Br. Ex., WP-10-R-NR-01, at 4.

Snohomish stated in oral argument that stepped rates are not necessary right now given the amount of the rate increase that currently seems likely. Kallstrom, Oral Tr. at 124. Snohomish also states that it is the frequency of small rate increases that causes concern, not the magnitude. *Id*. In its Brief on Exceptions, Snohomish supports BPA's decision not to adopt stepped rates but to allow customers to choose the Flexible PF Rate Option. Snohomish Br. Ex., WP-10-R-SN-01, at 3.

BPA Staff's Position

Staff considered a stepped rate alternative. Lovell *et al.*, WP-10-E-BPA-33, at 17. If parties are strongly favor stepped rates, Staff is willing to consider them. *Id*. at 18. Unless between now and the Final Proposal circumstances change in a manner that would make stepping the rates a worthwhile effort, however, Staff does not believe the additional process that may be needed to resolve unanticipated issues is worth the effort. *Id*. at 18.

Evaluation of Positions

Cowlitz, ICNU, Seattle, and WPAG state that BPA should adopt a stepped PF rate for FY 2010 and 2011. Cowlitz Br., WP-10-B-CO-01, at 1; ICNU Br., WP-10-B-IN-01, at 7; Seattle Br., WP-10-B-SE-01, at 1; WPAG Br., WP-10-B-WG-01, at 2, 10. These parties cite the economic recession as a reason for keeping wholesale rates as low as possible in the first year of the rate period and not raising rates at all if possible. Cowlitz Br., WP-10-B-CO-01, at 3-4; ICNU Br., WP-10-B-IN-01, at 7; Seattle Br., WP-10-B-SE-01, at 1-2; WPAG Br., WP-10-B-WG-01, at 2-3, 11. These parties state that BPA's establishment of stepped rates would help utilities by providing them with flexibility and allow them to keep rates to their retail customers lower in FY 2010, thus helping the economy. Cowlitz Br., WP-10-B-CO-01, at 3-4; ICNU Br., WP-10-B-IN-01, at 7-8; Seattle Br., WP-10-B-SE-01, at 1-2; WPAG Br., WP-10-B-WG-01, at 2-3, 11. The parties also base their support for stepped rates on the fact that BPA's forecast revenue requirement is lower for FY 2010 than it is for FY 2011 and claim that stepped rates would more accurately track BPA's revenue needs than having average rates for the rate period. Cowlitz Br., WP-10-B-CO-01, at 2-3; ICNU Br., WP-10-B-IN-01, at 8; Seattle Br., WP-10-B-SE-01, at 2-3; WPAG Br., WP-10-B-WG-01, at 10.

Staff agrees that the timing of when dollars are collected through rates can be a valid rate design consideration, although it needs to be appropriately balanced with other considerations, such as statutory requirements, simplicity, rate stability, practicality, revenue stability, cost and ease of administration, non-discrimination, and environmental protection. Fisher *et al.*, WP-10-E-BPA-36, at 8. As expressed by Cowlitz, ICNU, Seattle, and WPAG, the timing of any rate increase is particularly important in this rate case given the current state of the economy. A stepped approach to ratemaking would allow for a lower rate in FY 2010, when the economy would presumably be just starting to recover from the current recession, thus avoiding a higher rate increase in that year. Lovell *et al.*, WP-10-E-BPA-33, at 17. Then, in FY 2011, when the economy may be well on its way toward recovery, the rate would increase above what it would otherwise be in a two-year construct at a time when consumers could presumably more easily absorb such an increase. *Id*.

Snohomish does not support stepped rates, based upon its assumption that the upcoming rate increase will be relatively small. Kallstrom, Oral Tr. at 124. Snohomish states that "if we were talking double-digits increases, 15 percent rate increases, we might have a different story, but our understanding right now is we're in mid single digits and we believe that step rates bring with it complications that are not worth the small benefit that stepping the rates would provide." *Id*. Snohomish further elaborates by stating that its experience has shown that it is the frequency of small rate increases that causes problems in retail ratesetting, not the magnitude. *Id*.

For reasons similar to those expressed by Snohomish, NRU also does not support stepped rates at this time. NRU states that given developments since the Initial Proposal, including the additional Treasury short-term borrowing authority, anticipated cost reductions, lower augmentation needs and costs, and other tools available to BPA, it appears that BPA can manage the rate increase to an acceptable low to mid-single digit range. NRU Br., WP-10-B-NR-01, at 6. Based on this understanding, NRU argues, a stepped rate is unnecessary. *Id*.

NRU qualifies its position by noting that stepped rates should be developed if the rate increase is forecast to "greatly" exceed 5 percent. *Id*. at 6. NRU further clarifies that NRU members "overwhelmingly supported [a] flat rate for a two-year period, provided that the size of the initial rate increase is not larger than 5 percent." Saven, Oral Tr. at 218. Cowlitz disagrees with NRU's statement that BPA should consider stepped rates only if the average rate increase for FY 2010 and FY 2011 exceeds 5 percent. Cowlitz Br., WP-10-B-CP-01, at 4-5. Cowlitz points to the requests from many utilities for all available rate relief in FY 2010. *Id*. at 5.

One of NRU's primary arguments against stepped rates is that its members prefer rate stability over time, and every time BPA's rates change, utilities must review their own rates to ensure cost recovery. NRU Br., WP-10-B-NR-01, at 6. Snohomish makes a similar argument in oral argument. Kallstrom, Oral Tr. at 124. In response to concerns about rate stability, Cowlitz, ICNU, Seattle, and WPAG point out that an individual utility does not have to step its retail rates. They note that if BPA adopts stepped rates, utilities may choose to average the rate and not increase rates in FY 2011. Cowlitz Br., WP-10-B-CO-01, at 4; ICNU Br., WP-10-B-IN-01, at 9; Seattle Br., WP-10-B- SE-01, at 4; WPAG Br., WP-10-B-WP-01, at 11. Seattle states that even if a utility chooses not to pass through to its customers a lower stepped BPA rate in 2010, having lower wholesale power purchase costs could ease financial pressures on those utilities that are struggling to keep their retail rates down. Seattle Br., WP-10-B-SE-01, at 4. Cowlitz and ICNU argue that BPA could deprive utilities of this flexibility if it does not adopt stepped rates, and contend that it is in the public interest for BPA to give its customers as much flexibility as possible to tailor their retail rates to their individual service territories. Cowlitz Br., WP-10-B-CO-01, at 4; ICNU Br., WP-10-B-IN-01, at 10. Cowlitz proposes a possible compromise between those utilities that prefer stepped rates and those that prefer stable rates. Under Cowlitz's proposal, BPA would publish two rate schedules, one stepped and one flat, and the utilities could choose which rate schedule would apply to their power sales. Murphy, Oral Tr. at 110-111.

Because the request for stepped rates is being introduced late in the proceeding, unanticipated issues could emerge that would need to be resolved. Lovell *et al.*, WP-10-E-BPA-33, at 18. It is impossible to know ahead of time whether issues will arise, what those issues would be, or how much extra time resolution would take for BPA and parties. *Id.* Staff states that in the light of those concerns, and given the results of Staff's analysis of stepped rates, *id.* at Attachment 1, and the belief that the rate increase for FY 2010 can be limited sufficiently, the benefit of being able to reduce the FY 2010 rate still further is not likely to be worth the effort and expense of a more-complicated rate process and higher rates in FY 2011. *Id.* at 18.

Some customers have made it very clear that, given the economic situation, they wish to have a stepped rate option to mitigate the near-term effect of any rate increase on their retail customers. Clearly, the dire economic situation was one of the primary motivations for reviewing and revising the IPR program levels to lower the rate increase. See ROD section 2.3. The IPR2 close-out letter states that the economic situation and reduced 2009 BPA revenues "resulted in an imperative to focus on near term rates." However, the 2-year flat rate provides stability that is very important to other customers. Staff also has concerns over additional workload and expense and possible complications. It appears that all interests can be adequately addressed through the use of the Flexible Priority Firm Power Rate Option as described in the GRSPs, Appendix B to this ROD, section II.J. The Flexible PF Rate Option provides a mechanism for BPA to provide a stepped rate option without having to develop an alternative rate schedule. Under the Flexible PF Rate Option, BPA has the ability to mutually agree with the PF customer on the levels of the charges and billing factors. This option is already a part of the WP-10 rate proposal. The Flexible PF Rate Option allows BPA to adjust the charges such that they are equivalent on a net present value basis to the revenues BPA would have received under the posted PF rate schedule.

Cowlitz, ICNU, and WPAG expressed support for the idea of using the Flexible PF Rate Option as a mechanism for stepping the rates. Murphy, Oral Tr. at 115; Sanger, Oral Tr. at 209; Mundorf, Oral Tr. at 226. In their Briefs on Exceptions, Cowlitz, NRU, Snohomish, and WPAG also support BPA offering the Flexible PF Rate Option as a way for utilities to voluntarily step their BPA rates. Cowlitz Br. Ex., WP-10-R-CO-01, at 1; NRU Br. Ex., WP-10-R-NR-01, at 4; Snohomish Br. Ex., WP-10-R-SN-01, at 3; WPAG Br. Ex., WP-10-R-WG-01 at 4. While the

Flexible PF Rate Option was originally designed as a mechanism for a bilateral arrangement between BPA and an individual customer to shape the customer's payments, there is nothing to preclude its use to step the rates. In this regard, it would allow BPA to establish both a two-year unstepped rate for those customers that desire rate stability through the rate period and at the same time afford the flexibility associated with stepped rates that is very important to other customers. BPA will not offer a variety of different stepped options to the PF customers interested in stepped rates. Instead, BPA will offer to all interested PF customers a single payment option under the Flexible PF Rate Option with a fixed step between the rates in FY 2010 and FY 2011. The single payment option is described in Issue 3 below. Such payment option would remain subject to the Cost Recovery Adjustment Clause, Dividend Distribution Clause, NFB Adjustments, and any other applicable rate adjustments, charges, and special rate provisions. Election of the Flexible PF Rate Option by some customers would likely cause a very slight increase in the likelihood of a CRAC applicable to FY 2011 rates and a very slight decrease in the likelihood of a DDC applicable to FY 2011 rates.

Decision

BPA will not step the FY 2010 and FY 2011 rates. BPA will, however, use the Flexible PF Rate Option to create a fixed stepped payment option for all customers interested in that option.

Issue 2

Whether BPA should design and provide a mid-rate period process to determine whether the FY 2011 rates should be lowered.

Parties' Positions

ICNU states that BPA should adopt rates that provide the Administrator the discretion to reduce or eliminate any FY 2011 rate increase. ICNU Br., WP-10-B-IN-01, at 10. The Administrator could even reduce the FY 2011 rates if costs are lower or revenues are higher than projected. *Id*.

Seattle states that BPA should implement stepped rates with the option to lower rates for FY 2011 from the levels established in the WP-10 Final Record of Decision. Seattle Br., WP-10-B-SE-01, at 2-3. Seattle also states that while it supports the option to lower rates for FY 2011, stepped rates provide great value even if BPA fixes rates for both FY 2010 and FY 2011 without the possibility of subsequently reducing rates for FY 2011. *Id*.

Cowlitz PUD states that it might prefer that BPA retain the discretion not to implement the full second step if circumstances develop such that some or all of the postponed rate increase proves not to be necessary. Cowlitz Br., WP-10-B-CO-01, at 6. However, Cowlitz also states that getting a second look at the reasonableness of the forecast on which BPA develops the FY 2010 and FY 2011 rates is not the purpose of stepped rates. *Id*.

WPAG recommends that BPA adopt a stepped PF rate and that any percentage increase forecast for the second year of the rate period operate as a cap on the amount of any PF rate increase for the second year (absent the triggering of a CRAC adjustment). WPAG Br., WP-10-B-WG-01, at 11. WPAG argues that the GRSPs also should empower the Administrator to implement a second-year rate that is less than the percentage cap, or to forgo an increase altogether. *Id*. WPAG advocates a public process similar to that in the current CRAC mechanism before the second-year increase so BPA can respond to changed circumstances. *Id*. at 11-12.

NRU opposes a mid-rate period process; NRU does not support additional ratemaking processes in FY 2010 because of competing workload priorities. NRU Br., WP-10-B-NR-01, at 6.

BPA Staff's Position

Staff is concerned about the practicality of and need for some mid-rate period process to adjust FY 2011 rates. Lovell *et al.*, WP-10-E-BPA-33, at 18-19. In particular, a full-blown 7(i) process would be impractical given the competing 7(i) process for the 2012 rate case, the first rate case in which the Tiered Rate Methodology is implemented. *Id*. Staff acknowledges that more streamlined approaches other than a 7(i) process might be possible. *Id*.

Evaluation of Positions

The decision to opt for the use of the Flexible PF Rate Option to create a payment option in lieu of stepping the rates effectively renders moot the issue of whether there should be a mid-rate period adjustment proceeding.

Decision

BPA will not adopt a mid-rate period process to determine whether the FY 2011 rates should be lowered.

Issue 3

If BPA adopts stepped rates, at what level should the rates be stepped?

Parties' Positions

NRU states that stepped rates should be considered only if the Administrator cannot manage the rate increase to a mid-single digit increase. NRU Br., WP-10-B-NR-01, at 7.

Cowlitz proposes that each annual set of rates would be based on BPA's forecast revenue requirement and sales for the respective fiscal year. Cowlitz Br., WP-10-B-CO-01, at 2. Cowlitz also proposes that BPA back out the shift of amortization from FY 2011 into FY 2010 to further support a lower stepped rate in FY 2010. *Id*. at 3. Cowlitz disagrees with NRU and states that there is no merit to the argument that, during a severe recession, BPA should require customers to prepay FY 2011 costs in FY 2010 unless to do so would cause more than a low to medium single digit rate increase in FY 2010. *Id*. at 5. Cowlitz argues that BPA should step rates even if the result were no rate increase in FY 2010 or even a decrease. *Id*.

Seattle supports setting the FY 2010 rate at the level that recovers the FY 2010 revenue requirement and supports this method even if it results in a decrease when compared to FY 2009. Seattle Br., WP-10-B-SE-01, at 3.

ICNU states that if BPA is unable to maintain current rate levels for the two-year rate period, then it should adopt stepped rates to achieve a zero rate increase for FY 2010. ICNU Br., WP-10-B-IN-01, at 7. ICNU supports the proposal to base each year's rates on BPA's actual forecast costs and loads for that year. *Id*.

WPAG argues that BPA should reflect the fact that the revenue requirement for the first year of the rate period is considerably lower than the revenue requirement for the second year. WPAG Br., WP-10-B-WG-01, at 10.

BPA Staff's Position

Staff has not taken a position on this issue in the rate proceeding. Lovell *et al.*, WP-10-E-BPA-33, at 17.

Evaluation of Positions

The decision to opt for the use of the Flexible PF Rate Option to create a payment option makes it unnecessary to determine the difference between the rates for each year of the rate period. In developing a common payment option for a PF customer interested in differentiating its payments between FY 2010 and FY 2011, BPA will offer a single payment option under the Flexible PF Rate Option with equal steps between the rates in FY 2009, FY 2010, and FY 2011. That is, the flexible payment option will be structured so that the FY 2009 to FY 2010 increase is equal to the FY 2010 to FY 2011 increase. Consistent with the terms of the Flexible PF Rate Option, the forecast revenues from the flexible payment option must be equivalent, on a net present value basis, to the revenues BPA would receive under the posted two-year PF Preference rate.

Decision

BPA will not step the PF Preference rate but will use the Flexible PF Rate Option for interested customers to determine a single common alternative payment plan that effectively creates equal steps in the payment.

14.3 Customer Charge

A customer charge, as presented in the WP-10 rate case, would be a charge in BPA's rate schedules that would collect an equal amount of revenue from each of BPA's PF Preference customers. The amount of power purchased from BPA by a PF Preference customer would not affect the amount paid through the customer charge. BPA currently does not use a customer charge in its wholesale power rates but instead recovers its costs through volumetric charges that increase or decrease the amount paid depending on the amount of power purchased from BPA.

Issue 1

Whether BPA should include a customer charge in its FY 2010-2011 rates or direct Staff to conduct a quantitative and policy study for FY 2012.

Parties' Positions

Snohomish PUD is concerned that the lack of a monthly customer-specific charge in BPA rates is leading to a cross-subsidy between BPA customers. Snohomish Br., WP-10-B-SN-01, at 2; Snohomish Br. Ex., WP-10-R-SN-01, at 3. Snohomish also is concerned that, without customer charges, appropriate price signals will not be sent to current and prospective BPA customers. *Id*. at 3.

WPAG disagrees with Snohomish, stating that the proposal to impose a customer charge to collect a small portion of BPA's total costs appears to be neither timely nor worth the effort. Based on these considerations, WPAG states, the proposal for BPA to adopt a customer charge should not be implemented. WPAG Br., WP-10-B-WG-01, at 27.

BPA Staff's Position

Staff recommends that the Administrator not adopt Snohomish's proposed customer charge. Fisher *et al.*, WP-10-E-BPA-36, at 7.

Evaluation of Positions

BPA is a wholesale energy provider that sells relatively large quantities of energy and capacity throughout a large geographic region and primarily to a utility customer base of fewer than 150 utilities. Fisher *et al.*, WP-10-E-BPA-36, at 5. BPA's customers, in contrast, distribute electricity to thousands of consumer meters within comparatively small geographic boundaries. *Id*. When compared to many utilities serving at a retail level, BPA's small customer base and large purchase volume create a much different ratio of volume-related costs (energy and demand) to customer-related costs. *Id*. This ratio, in conjunction with BPA's customers being utilities, has resulted in BPA's PF Preference rate design focusing on volume-related costs that are more complex and granular than the retail rates adopted by most retail utilities. *Id*. at 5-6.

Snohomish objects to Staff's proposal to design PF Preference rates based solely on volume-related energy and demand charges. Snohomish Br., WP-10-B-SN-01, at 2. Instead, Snohomish argues, BPA should adopt a "customer charge." *Id*. As noted above, a customer charge collects an equal amount of revenue from each of BPA's PF preference customers. The amount of power purchased from BPA by a PF preference customer would not affect the amount paid through the customer charge.

Snohomish argues that a customer charge is warranted in this case because the lack of a monthly customer-specific charge in BPA rates is leading to a "cross-subsidy" between BPA customers. Snohomish Br., WP-10-B-SN-01, at 2. Snohomish points out that monthly customer charges are commonly used to recover costs that are causally related to the number of customers served by a utility, as opposed to the volume of electricity sold. *Id*. at 2-3. For BPA, Snohomish states that these activities include meter maintenance, meter reading, bill processing, public relations, rate case work, and Account Executive staffing. *Id*. at 3.

WPAG objects to Snohomish's request for a customer charge. WPAG Br., WP-10-B-WG-01, at 26. WPAG points out that the costs cited by Snohomish would fall within BPA's customer support service cost category; assuming, *arguendo*, that all these costs do not vary by customer size or usage, this cost category constitutes only about $11 million of the total BPA fiscal year budget. *Id.* at 27. WPAG states that establishing a separate charge to collect this portion of BPA's costs seems counterproductive; it also is untimely, because in the next rate proceeding BPA will be establishing rates governed by the Tiered Rate Methodology. *Id.*

BPA concurs with the observations made by WPAG and agrees that Snohomish's request for a customer charge may be flawed and is untimely. Cost causation is a primary consideration of BPA's ratemaking, but it must be balanced with other considerations, such as statutory requirements and customers' continuing desire for simplicity in rate design. Fisher *et al.*, WP-10-E-BPA-36, at 6. With regard to simplicity, BPA's proposed rate design is already considered to be frustratingly complex, as Snohomish has noted. Snohomish Br., WP-10-B-SN-01, at 17. The addition of another rate component would certainly add to the complexity. Fisher *et al.*, WP-10-E-BPA-36, at 6.

To support its "cross-subsidy" argument, Snohomish argues that the costs of certain activities, such as meter maintenance, meter reading, bill processing, public relations, rate case work, and Account Executive staffing, are commonly recovered in customer-related charges. Snohomish Br., WP-10-B-SN-01, at 3. Snohomish contends that because these shared infrastructure costs are recovered through energy and demand rates, BPA customers that purchase large volumes of power (such as Snohomish) pay a disproportionate share of these types of costs. *Id.* at 4.

Snohomish's select list of costs for inclusion in the customer charge demonstrates why developing a customer charge is problematic and is best considered through informal workshops. A customer charge can lead one party to cherry pick the "cross-subsidy" of customer-related costs without consideration of all possible cross-subsidies. Fisher *et al.*, WP-10-E-BPA-36, at 7. For example, under Snohomish's proposition, it would be just as reasonable to propose a "complexity charge," a "number of resources charge," a "contentiousness charge," or a "number of meters charge." *Id.* Moreover, it should be noted that many of Snohomish's examples of equivalent customer-related costs are not soundly based and hence, in BPA's opinion, erroneous examples. *Id.* For example, costs incurred by billing or Account Executive staffing are generally incurred proportionate to the complexity (which generally relates to size) of the customer at hand; BPA has Account Executives assigned to as few as four customers (high-complexity customers, such as Snohomish) or as many as 18 (low-complexity customers). *Id.* at 7-8. The same example would also apply for billing. *Id.* at 8. Meter maintenance costs are also a poor example of a cost that should be divided by the number of customers BPA has, because the cost generally is tied to the number of meters (often related to customer size), and not to the number of BPA customers. *Id.*

Snohomish also states that it is concerned that, without customer charges, appropriate "price signals" will not be sent to current and prospective BPA customers. Snohomish Br., WP-10-B-SN-01, at 3. Under the current rate structure, Snohomish claims, BPA service will appear more attractive to new consumer-owned utilities than would be the case if rates contained no cross-subsidies. *Id.* Further, Snohomish states, showing BPA's customer-related expenses as a separate line item on customer bills would provide customers the ability to "judge BPA's performance." *Id.*

Snohomish's arguments are not persuasive. First, Snohomish does not explain what purpose would be served by sending a "price signal" in the form of a customer charge to current or prospective customers. In testimony, Snohomish appears to suggest that the customer charge would be used to discourage new consumer-owned utilities from forming and seeking power from BPA. *See* Toulson, WP-10-E-SN-01-CC01, at 8. If this is what Snohomish intends to achieve with the customer charge, then Snohomish's proposal is seriously misplaced. BPA does not believe that a customer charge would be a significant signal to the overall cost of service to a new utility. Fisher *et al.*, WP-10-E-BPA-36, at 8. Barring a significant or insignificant customer charge cost, Snohomish's argument assumes a small size of the new consumer-owned utility, which assumption erroneously forms their conclusion. *Id*.

Snohomish also notes that a customer charge would enable customers to "judge BPA's performance." Snohomish Br., WP-10-B-SN-01, at 3. Once again, Snohomish does not elaborate on how a customer charge would accomplish this objective. Furthermore, it is unclear to BPA how a customer charge would place BPA's customers in a better position to assess BPA's "performance" than under BPA's current rate design. Snohomish's proposed customer charge would assign a set dollar amount to each BPA customer for certain cost items, with the result that all customers would be charged the same amount for certain BPA services. BPA does not understand how this outcome, which places costs on utilities regardless of their actual use of BPA's services, will put preference customers in a better position to "judge BPA's performance."

Snohomish next argues that Staff has offered "scant evidence in support of its position." Snohomish Br., WP-10-B-SN-01, at 3. Snohomish contends that Staff states that BPA is different in that it is a wholesale energy provider rather than a retail energy provider. *Id*. Snohomish alleges that while Staff argues that this difference has led to a rate design primarily focused on customer load rather than cost causation, Staff fails to offer any meaningful reason for this focus. *Id*. Snohomish's criticism is unfounded. Staff explains in detail in testimony the basis for BPA's current rate design proposal and the rationale for rejecting Snohomish's customer charge. Those reasons include the differences that inherently exist between a retail distribution utility (which may have thousands of customers to spread the charges across) and BPA (which has about 150). Fisher *et al.*, WP-10-E-BPA-36, at 5. In addition, Staff explains that designing a customer charge would make BPA's complex rate structure even more complex. *Id*. at 6. Finally, Staff examines the potential problems of picking the costs that would go into a customer charge. *Id*. at 7. By introducing a customer charge into BPA's rate design, an entire new level of contentiousness could be present as parties seek to "cherry-pick" the costs they believe should be included in the customer charge. *Id*. As can be seen, Staff notes several sound reasons for its recommendation that the Administrator reject Snohomish's suggested customer charge. Consequently, Snohomish's assertion that Staff provides "scant evidence" to support their position is baseless.

Snohomish argues that Staff's actions and statements in this rate proceeding suggest the importance of cost causation in BPA ratemaking. Snohomish Br., WP-10-B-SN-01, at 3. Snohomish argues that Staff states in its Wind Balancing rate testimony that "rigorous application of the cost-causation principle of ratemaking is key to fair and non-discriminatory power and transmission rates." *Id*. The fact that BPA is committed to designing its rates based on general cost-causation principles does not mean that BPA must apply this concept in every conceivable manner, regardless of the amount of costs at issue and consideration of administrative efficiency and cost. In the context of the Wind Balancing rate testimony cited by Snohomish, those principles serve to ensure that the parties taking the Wind Balancing Service pay an appropriate share of the costs of the Federal system. In the context of BPA's preference rates, cost-causation principles are met by charging customers based on demand and energy consumption.

Snohomish continues its argument by claiming BPA has in other contexts made attempts to avoid cost shifts between customers. Snohomish Br., WP-10-B-SN-01, at 3. Snohomish points to BPA's separation of Slice and non-Slice costs as an example. *Id*. at 3-4. There, Snohomish claims that Staff devotes an entire section of testimony to revising FY 2010-2011 rates to eliminate "a potential cost shift related to the forecast Slice True-Up Adjustment Charge." *Id*. Snohomish argues that Staff's proposed solution is to move certain costs from FY 2011 to FY 2010, all to avoid one customer class from paying costs imposed on BPA by another customer class. *Id*. In addition, BPA's current practice is to separately track costs associated with BPA's trading floor activities and costs associated with implementing the Slice product. *Id*. These costs are then billed to the customer class that benefits from the respective services. *Id*.

Snohomish's comparison is once again inappropriate, because it fails to recognize the distinct difference of Slice product design and non-Slice product design. In order to offer the Slice product, BPA and customers established the principle that there should be no cost shifts to non-Slice customers as a result of BPA offering the Slice product. Subscription Strategy ROD, December 1998, at 85, 99; WP-02 ROD, WP-02-A-02, at 16-2. While cost causation within products is an important feature of rate design, it must be balanced with other considerations, such as statutory requirements, simplicity, rate stability, practicality, revenue stability, cost and ease of administration, non-discrimination, and environmental protection. Fisher *et al.*, WP-10-E-BPA-36, at 8.

Snohomish argues that despite the rhetoric of Staff in its rebuttal of Snohomish, BPA's statements and actions demonstrate the importance of remedying cost-shifts and cross-subsidies contained in BPA rates. Snohomish Br., WP-10-B-SN-01, at 4. Snohomish identified that large customers pay a disproportionate share of the total BPA administrative overhead costs and thereby subsidize smaller BPA customers. *Id*. Snohomish asks that the Administrator remove this subsidy by developing and applying an appropriate customer charge. *Id*.

Although BPA can understand Snohomish's interest in having costs allocated among all of BPA's customers, BPA cannot agree that the way to accomplish this goal is by simply adopting a rate design that substantially prejudices BPA's smaller customers. It is not enough to assert a principle of economics to justify a particular rate design. Fisher *et al.*, WP-10-E-BPA-36, at 8. Economic efficiency is an important consideration when structuring rates, but it is by no means the only one, or even the foremost. *Id*. One consideration that BPA believes is very important, but that seems to have been completely ignored in Snohomish's brief, is the fundamental principle of fairness. While cost causation is grounded in notions of fairness, Snohomish's proposal would have BPA treat customers of vastly different sizes as equals for purposes of recovering costs. Thus, under the customer charge proposed by Snohomish, BPA would allocate to BPA's smallest customer the same amount of costs that would be allocated to BPA's largest customer. This approach would have a negative impact on BPA's smallest customers. WPAG noted that Snohomish's proposal for a customer charge will work a financial hardship on BPA's smallest preference customers while providing no discernible benefit to its largest preference customers. WPAG Br., WP-10-B-WG-01, at 27. WPAG's point becomes particularly clear considering that BPA's eight smallest customers have annual power bills of approximately $125,000 or less, with the smallest customer having an annual bill of approximately $25,000. *Id*. BPA agrees with WPAG. Assuming WPAG's assessment of the costs that might be assigned to a customer charge of about $11 million, dividing $11 million among 135 preference customers would result in a customer charge of about $80,000 per year. This would be a 60 percent rate increase to a $125,000 customer and 320 percent rate increase to the $25,000 customer. BPA cannot see why imposing a customer change on such small customers would be either fair or necessary.

In its Brief on Exceptions, Snohomish once again asks BPA to consider incorporating a customer charge into its ratesetting methodology to ensure a fair allocation of service overhead among all of its wholesale customers. Snohomish Br. Ex., WP-10-R-SN-01, at 3. As support, Snohomish alleges that BPA "seemingly agrees" that larger customers such as Snohomish are "subsidizing smaller customers." *Id*. at 3-4. Snohomish's characterization of the Draft ROD is incorrect. Nowhere in the Draft ROD did BPA "agree" that larger customers are subsidizing smaller customers. The only place where BPA "agreed" with Snohomish was in the response just noted above, where BPA granted that it "understands" Snohomish's desire to allocate costs to other utilities. If that is what Snohomish is referring to in its brief to support its argument, then its reading of the Draft ROD is in error. Understanding does not equal agreement.

Snohomish states that even though there may not be sufficient time in this rate proceeding to fully evaluate Snohomish's proposal or fully develop specific customer charges, Snohomish requests a commitment by the Administrator to carry out a quantitative and policy study for the FY 2012-2013 rate proceeding regarding instituting monthly customer-related charges. Snohomish Br., WP-10-B-SN-01, at 4. BPA is concerned that there are a number of other pressing issues that BPA and the region must address before the commencement of BPA's next rate proceeding. BPA must have flexibility to allocate the time of its staff to address the most immediate and important concerns facing the agency and the region. For example, as noted by WPAG in its brief, one of the key tasks that BPA and the region must prepare for is the establishment of rates in accordance with the Tiered Rate Methodology. WPAG Br., WP-10-B-WP-01, at 27. Snohomish itself points out that modifications, improvements, and documentation of the Rate Analysis Model is a concern and that the Administrator should fully support Staff in its endeavor to provide the RAM information to customers as soon as it is ready. Snohomish Br., WP-10-B-SN-01, at 17-18. As such, BPA does not believe that it would be prudent to commit in this proceeding to dedicate limited staff time to study a change in rate design without a show of support from a broader base of customers. If Snohomish can rally such support, BPA is willing to engage in discussions to explore the issue further.

In its Brief on Exceptions, Snohomish claims that BPA stated in the Draft ROD that Snohomish's proposal would be considered only if Snohomish could show a coalition of support from a broad base of customers. Snohomish Br. Ex., WP-10-R-SN-01, at 4. BPA did not mean to imply that Snohomish must garner support for its proposal to be considered on its fundamental merits *in a rate proceeding*. As noted above, Snohomish requested that BPA dedicate staff time and resources to conduct "quantitative and policy study" on the merits of a customer-related charge in preparation for the FY 2012-2013 rate proceeding. Snohomish Br., WP-10-B-SN-01, at 4. Because this request asks BPA to commit limited staff time to matters that have no relevance *in this rate proceeding*, BPA stated that it would consider Snohomish's request *to commit staff time* for a quantitative and policy study only if Snohomish could rally support from other customers. Draft ROD, WP-10-A-01, at 300. As is plainly clear, BPA did not say that it would consider Snohomish's proposal *in a rate proceeding* only if it was supported by a "coalition" of customers.

Snohomish then asks BPA to review Snohomish's customer charge costs as part of BPA's overall rate design methodology to determine a proper allocation among preference customers. Snohomish Br. Ex., WP-10-R-SN-01, at 4. Snohomish asks that if supporting data and arguments are sound, it expects that its customer charge rate proposal would be seriously considered for inclusion into the Final Record of Decision for this proceeding or the next BPA rate case, regardless of the level of regional support. *Id*. Snohomish asks BPA to judge the proposed customer charge based upon the fundamental merits of information or evidence that is developed by BPA and other parties, not on the popularity of the proposal. *Id*.

Although not recognized by Snohomish, BPA has already considered the limited facts Snohomish has presented on the record of this case and determined on the merits that for this rate period a customer charge should not be adopted. BPA's decision in this regard is not because Snohomish's proposal was not supported by a "coalition" of customers. Rather, as discussed above, BPA reaches this decision after carefully considering Snohomish's arguments and limited evidence as well as the arguments and evidence of all the parties to this case. After reviewing these arguments and evidence, BPA finds that the weight of the record supports a continuation of BPA's current rate design practice, which does not include a customer charge. For the WP-12 rate proceeding BPA expects that the Tiered Rate Methodology will govern the procedures under which Snohomish can propose this type of change in rate design.

Furthermore, Snohomish asks that BPA commit to carry out a quantitative and policy study of its customer charge proposal for the FY 2012-2013 rate proceeding regarding instituting monthly customer-related charges. Snohomish Br., WP-10-B-SN-01, at 4. In contraposition, Snohomish believes BPA should not initiate a new section 7(i) rate proceeding to examine a variable IP rate during 2010 and 2011 because BPA's customers are already facing an extremely burdensome workload as the region prepares for the first rate period under the new Regional Dialogue contracts and Tiered Rate Methodology. Snohomish Br. Ex., WP-10-R-SN-01, at 5. BPA finds it difficult to reconcile the dichotomy between the Snohomish position on each issue. Snohomish evidently believes that it is acceptable to spend BPA's time and money on an issue it deems important (while endorsing arguments for BPA to cut its costs, Snohomish Br., WP-10-B-SN-01, at 2), but not on an issue that is important to another customer.

<u>Decision</u>

BPA will not include a customer charge in its FY 2010-2011 rates and, at this time, will not direct Staff to conduct a quantitative and policy study for FY 2012.

14.4 General Transfer Agreement (GTA) Delivery Charge

The General Transfer Agreement (GTA) Delivery Charge applies to PF customers for deliveries of power over a third-party transmission and/or distribution system at voltages below 34.5 kV. Rogers and Garrett, WP-10-E-BPA-29, at 2. This third-party transmission service is commonly referred to as "transfer service" and includes legacy contracts, Open Access Transmission Tariff service, and other transmission arrangements. *Id*. The customer pays the GTA Delivery Charge only if the customer receives transfer service at voltages below 34.5 kV and is not paying Transmission Service's Utility Delivery Charge for that particular point of delivery. *Id*.

In the WP-07 rate proceeding, the GTA Delivery Charge was set at a level equal to the Utility Delivery Charge in the Transmission Services Transmission and Ancillary Service rate schedule. *Id*. For the WP-10 rate period, Power Services proposed to continue this practice, with one minor modification. *Id*. at 2-3. Previously, the GTA Delivery Charge would appear in the final rate schedules as a monthly per-kilowatt rate that was the same as the Transmission Services Utility Delivery Charge. *Id*. at 3. For the WP-10 rate period, however, BPA proposed a formula rate that simply references the Transmission Services Utility Delivery Charge. *Id*. That is, in the presentation of the GTA Delivery Charge in the rate schedules, the GTA Delivery Charge will have a reference to the Transmission Services rate schedule for the relevant rates and billing determinants. *Id*. This change has no impact on the level of the GTA Delivery Charge.

No parties raised an issue with Staff's proposal for the GTA Delivery Charge. The GTA Delivery Charge will be modified as Staff proposes.

14.5 Supplemental Direct Assignment Guidelines

The Supplemental Direct Assignment Guidelines are guidelines that Power Services uses in combination with Transmission Services' Guidelines for Direct Assignment Facilities to determine whether to recover the costs of direct assignment facilities from transfer service customers. Rogers and Garrett, WP-10-E-BPA-29, at 5. The Supplemental Direct Assignment Guidelines are applicable only to customers BPA serves over third-party transmission systems. *Id*. at 6.

Previously, the only document available that articulated BPA's policy regarding when direct assignment costs would be recovered from transfer service customers was Transmission Services' Guidelines for Direct Assignment Facilities. *Id*. To fill this gap, Power Services published the Supplemental Direct Assignment Guidelines as part of the July 2007 Long-Term Regional Dialogue Final Policy. *Id*. Power Services committed in the July 2007 Record of Decision accompanying the July 2007 Long-Term Regional Dialogue Final Policy to propose to include the Supplemental Direct Assignment Guidelines in the WP-10 Initial Proposal to make certain that all customers would have access to Power Services policy on direct assignment responsibilities. *Id*.

No parties raised an issue with Staff's proposal for the Supplemental Direct Assignment Guidelines. The Supplemental Direct Assignment Guidelines will be adopted as Staff proposes.

14.6 Transfer Service Operating Reserve Charge

The Transfer Service Operating Reserve Charge applies to PF customers that meet the following criteria: first, the customer must be a Power Services transfer service customer; second, the customer must not be paying Transmission Services for Operating Reserves based on 3 percent of the customer's load; and third, Power Services must be assessed Operating Reserve charges from a third-party transmission provider to transmit Federal power to the power customer's load, or Power Services must be self-providing Operating Reserve in lieu of paying a third-party transmission provider for the Operating Reserve. Rogers and Garrett, WP-10-E-BPA-29, at 7.

Presently, Power Services does not acquire Operating Reserves from third-party transmission providers for the transmission of Federal power to transfer service customers. Instead, transfer service customers meet their Operating Reserve obligation by acquiring these services from Transmission Services. *Id*. at 8. The Commission is considering a Western Electricity Coordinating Council proposal to change the Operating Reserve requirement. *Id*. If the Commission adopts the proposed change, Power Services may be required to acquire (pay for) Operating Reserve from third-party transmission providers to serve transfer service customers. *Id*. This will increase Power Services' costs of providing transfer service. *Id*. At the same time, transfer service customers will experience a reduction in costs paid to Transmission Services, as a portion of the Operating Reserve obligations shifts to Power Services. *Id*. The Transfer Service Operating Reserve Charge is designed to allow Power Services to recover these potential new costs. *Id*.

The Transfer Service Operating Reserve Charge rates will mirror Transmission Services' Operating Reserve rates, and will consist of two rates: one that mirrors Transmission Services' Operating Reserve – Spinning Reserve Service rate, and one that mirrors Transmission Services' Operating Reserve – Supplemental Reserve Service rate. *Id*. at 8-9. Power Services will charge the above rates in the same manner that Transmission Services charges its customers, except that Power Services will charge for only the portion of reserve obligation that is based on the customer's load, and not the portion based on generation. *Id*. at 9.

No parties raised an issue with Staff's proposal for the Transfer Service Operating Reserve Charge. The Transfer Service Operating Reserve Charge will be adopted as Staff proposes.

14.7 Green Energy Premium (GEP)

Issue 1

Whether BPA should establish the Green Energy Premium (GEP) price based on forecasts of environmental attributes in the Pacific Northwest alone or in combination with the Western Electricity Coordinating Council (WECC)-wide and California markets.

Parties' Positions

NRU requests additional clarity on how GEP will be priced, and recommends that BPA base the price on a forecast of market prices of environmental attributes (*i.e.*, Renewable Energy Certificates (RECs)) in the Pacific Northwest rather than a WECC-wide or California market forecast of REC market prices. NRU Br., WP-10-B-NR-01, at 9-10.

BPA Staff's Position

The GEP is priced at the value of the associated environmental attributes expected to be produced by resources included in the Environmentally Preferred Power (EPP) and Alternative Renewable Energy (ARE) portfolio and any contractual call rights for EPP and ARE. Ingram *et al.*, WP-10-E-BPA-17, at 11. GEP is priced by the trading floor, and thus a precise price for GEP is not set in the rate case. Further, in determining the value of environmental attributes it is not reasonable to limit the GEP price to the Pacific Northwest, particularly because BPA sells RECs throughout the WECC area, which is a West Coast-wide market. Malin *et al.*, WP-10-E-BPA-37, at 2.

Evaluation of Positions

First, NRU states that the GEP should be based on the Pacific Northwest market because the environmental attributes associated with the GEP will be used by utilities located in the Pacific Northwest and retired within the Pacific Northwest. NRU Br., WP-10-B-NR-01, at 9-10. NRU argues that the Pacific Northwest market is a more appropriate market to use than the WECC-wide and California markets because the utilities that will be paying the GEP are located in the Pacific Northwest and the environmental attributes associated with this GEP will be retired within the Pacific Northwest. *Id*. Although the GEP is used by utilities within the Pacific Northwest market, the non-power environmental attribute component of GEP (*e.g.*, RECs) can be sold throughout the WECC area, which is a West Coast-wide market. Malin *et al.*, WP-10-E-BPA-37, at 2. Therefore, it is not reasonable to limit the basis of the GEP price to the Pacific Northwest market. In addition, contrary to NRU's assertion, it is possible that the environmental attributes associated with the GEP may be retired outside of the Pacific Northwest if they are sold outside of the Pacific Northwest.

Second, NRU contends that WECC-wide and California market prices are potentially volatile and will be dominated by speculation, statutory and regulatory RPS requirements, and other California activity unrelated to the Pacific Northwest. NRU Br., WP-10-B-NR-01, at 10. This contention is not persuasive for several reasons. First, NRU fails to point to any evidence in the record that supports this argument. Contrary to NRU's assertion that the WECC-wide and California markets are characterized by "potentially volatile" prices and are "dominated by speculation," it is BPA's experience that the WECC market is less volatile and more liquid than the Pacific Northwest market. The Pacific Northwest market prices are influenced by the participation of a single large party, and thus the Pacific Northwest market is not as liquid. Further, BPA has never proposed using a strictly California market, so any volatility and uncertainty associated with the California markets is of diminished significance. Instead, Staff proposes to consider WECC-wide market prices; WECC includes California and many other western states. In addition, Staff proposes to set the price for GEP prior to the rate period, for the entire rate period, and as such is providing a hedge against market volatility. Finally, NRU utilities have the option to purchase RECs from the Pacific Northwest market independent of BPA if they so choose.

Decision

BPA will continue to consider the WECC-wide market when setting GEP prices. The WECC-wide market provides a reasonable basis to establish GEP prices.

14.8 Value of Reserves for the Industrial Firm Power (IP) Rate

Issue 1

Whether the value of DSI reserves should be set in the WP-10 rate proceeding.

Parties' Positions

Alcoa requests that BPA take up the issue of crafting the mechanics of its reserves in the long-term contract negotiations. Alcoa Br., WP-10-B-AL-01, at 11.

The IOUs argue that any absence of executed DSI contracts does not and should not prevent BPA from making a reasonable forecast for the FY 2010-2011 rate period of the reserve benefits from DSI contracts. IOU Br., WP-10-B-JP1-01, at 86.

BPA Staff's Position

BPA Staff believes that, consistent with statutory directives, BPA should establish a Value of Reserves credit in the WP-10 rate proceeding that will apply to the rate for Industrial Firm Power (IP rate). Fisher *et al.*, WP-10-E-BPA-36, at 21-22. This reserve obligation will ultimately be incorporated in any contracts for the provision of DSI service at the IP rate. *Id*.

Evaluation of Positions

The Northwest Power Act authorizes the Administrator to sell power to the DSIs during the period following the expiration, termination, or modification of the 1981 power sales contracts required by section 5(d)(1)(B) of the Northwest Power Act (16 U.S.C. § 839c(d)(1)(B)). 16 U.S.C. § 839c(d)(1)(A); *PNGC*, 550 F.3d 846, 854 (9th Cir. 2008). The authorizing provision also provides that "[s]uch sales shall provide a portion of the Administrator's reserves for firm power loads within the region." 16 U.S.C. § 839c(d). Section 7(c) of the Northwest Power Act delineates the manner in which the rate for service to DSI loads will be developed for the period beginning July 1, 1985, which period includes discretionary DSI sales after the expiration or termination of the 1981 DSI power sales contracts, as will be the case for any future DSI contracts. 16 U.S.C. § 839e(c)(1)(b). In addition to other ratemaking requirements not relevant to resolution of this issue, the Act is explicit that "[t]he Administrator shall adjust such rates to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers." 16 U.S. C. § 839e(c)(3). The Act provides further that in establishing rates, the Administrator "shall" do so in accordance with the procedural requirements detailed in section 7(i). 16 U.S.C. §§ 839e(i)-839e(i)(6).

Because determining the amount of the statutorily required value of reserves credit is an adjustment to the IP rate, which constitutes an exercise in ratemaking, and because ratemaking is required to be accomplished through a section 7(i) process, it is reasonable for BPA to conclude that establishing the value of any mandatory reserve requirement for DSI service should be accomplished in the context of the required procedures. Doing so results in a transparent process for establishing the value of such reserves and provides interested parties with an opportunity to test the methodology employed by BPA to make the relevant calculations.

Alcoa notes that during the WP-10 rate proceeding, a number of BPA customers express concern that BPA has not yet developed its longer-term DSI contracts and therefore cannot be sure of a match between the DSI reserve credits and the curtailment provisions in the DSI contracts. Alcoa Br., WP-10-B-AL-01, at 10. Alcoa states that the curtailment rights Alcoa presented in testimony could provide BPA and its customers with substantial operating advantages in the future. *Id*. at 11. Alcoa urges BPA to take up the issue of crafting the mechanics of its reserves in the long-term contract negotiations. *Id*.

Based on BPA's reading of the statutory requirements, the issue of whether DSI contracts are or are not currently in place is immaterial. The statutory requirement is clear. DSI sales "shall" provide some quantum of BPA's regional reserves for firm power loads. The value of those reserves "shall" be established pursuant to an adjustment to the IP rate. Such ratemaking "shall" be accomplished in accordance with the ratemaking procedures established by the Act. Given the repeated use of the mandatory directive "shall," it would not be reasonable to conclude that BPA has the unfettered discretion to address the DSI reserve issue completely independent of the statutory ratemaking process.

To the degree that the absence of signed DSI contracts is an issue, BPA agrees with the IOUs. Forecasting is an inevitable part of the ratemaking process, as is suggested in the Initial Brief of the IOUs, who state, in pertinent part:

> Any absence of executed DSI contract does not and should not prevent BPA from making a reasonable forecast of the reserve benefits for the FY 2010-2011 rate period from DSI contracts. Indeed, BPA consistently forecasts revenues from sale of secondary energy in rate proceedings when, for most of such forecasted sales, BPA does not have contracts in place for specific sales of secondary energy.

IOU Br., WP-10-B-JP1-01, at 86. In this proceeding, BPA has forecast that it will serve up to 402 aMW of DSI load. BPA believes this forecast is sufficient to satisfy cost recovery and other ratemaking requirements. Because any DSI service will be contingent upon provision of the reserves as specified in the IP rate schedule, any contract for DSI service under the IP rate will inevitably need to incorporate those reserve provisions. Thus, BPA sees no compelling necessity to have contracts in place prior to establishing the value of reserves credit.

Alcoa has indicated that it may be able to provide types of reserves additional to those contemplated in establishing the value of reserves credit. The reserve credit itself, however, does not necessarily foreclose BPA from obtaining more reserves or different types of reserves from DSIs that have the ability to provide value to BPA in ways other than those described in connection with the IP rate. In fact, Alcoa suggests that aluminum smelters specifically may be well positioned to provide BPA and its customers with substantial operating advantages in the future. Alcoa Br., WP-10-B-AL-01, at 11. Alcoa describes in its testimony a number of products that it believes could be made available. Speer, WP-10-E-AL-01, at 8-11. The reserve credit is designed only to provide value for a "portion" of the Administrator's reserves for regional firm power loads. Therefore, the statute does not require that BPA foreclose potential opportunities to determine whether the DSIs, like any other prospective supplier, can provide additional products and services that could serve BPA's needs.

Decision

BPA will establish a credit on the IP rate that will compensate DSI customers for the value of providing the level and type of reserves defined in the WP-10 IP rate schedule and associated General Rate Schedule Provisions.

Issue 2

Whether BPA has properly established the parameters for reserves required to be provided for DSI service under the IP rate.

Parties' Positions

APAC states that until a contract with the DSIs is negotiated, the value of DSI reserves is uncertain. APAC Br., WP-10-B-AP-01, at 14. In the meantime, APAC argues, BPA must be conservative in setting those values; given that there is no certainty regarding the contracts, the amount of reserves and their value should be set very low. *Id*. APAC clarifies that it does not contend that BPA should not make an estimate, only that it must be conservative while the terms of any contract have yet to be negotiated. APAC Br. Ex., WP-10-R-AP-01, at 8. But APAC also reiterates that until a contract is negotiated and a DSI agrees to take service of some as-yet unknown amount under the terms of the IP rate, the value cannot be determined. *Id*.

PPC *et al.* argue that the highly speculative nature of DSI customers as a source of reserves does not warrant any reduction in the IP rate. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 6. PPC *et al.* state that BPA's proposed treatment of this issue only serves to shift even more risk and increased costs to the agency's preference customers and does not comport with section 7(c)(3) of the Northwest Power Act, which directs the Administrator to adjust the IP rate to take into account the value of reserves "made available to the Administrator *through his rights* to interrupt or curtail service to such direct service industrial customers." *Id*.

PNGC speculates that BPA apparently intends to provide increased subsidies to its DSI customers by means of a dramatically increased VOR credit amount. PNGC Br. Ex., WP-10-R-PN-01, at 4. PNGC states that such a decision is inconsistent with sound business practices. *Id*. PNGC claims that such a decision would allow the DSIs to benefit immediately from a large VOR credit before the physical means of providing the reserves is even put in place. *Id*. Further, PNGC states, under present economic circumstances, a decision by BPA to use this device to reduce the IP rate while it is substantially increasing the PF rate is clearly inequitable. *Id*.

The IOUs state that BPA should assume DSI interruption rights that would provide for operating reserves equal to, at a minimum, one-half the total average forecast DSI load for the rate period, exclusive of wheel-turning load. IOU Br., WP-10-B-JP1-01, at 71-72; IOU Br. Ex., WP-10-R-JP1-01 at 15-19.

BPA Staff's Position

BPA Staff has revised the expected value of reserves provided by the DSIs from $20,000 per year or $0.01 per MWh in the Initial Proposal to roughly $3 million or $1/MWh as a result of further investigation reflected in BPA's rebuttal testimony. Fisher *et al.*, WP-10-E-BPA-36, at 24.

Evaluation of Positions

APAC states that calculation of rates requires BPA to assess three separate factors in calculating the value of DSI reserves used in the 7(b)(2) rate test: 1) the amount of reserves available and the conditions for their use; 2) the value of those reserves; and 3) the credit provided to the DSIs for the reserves. APAC Br., WP-10-B-AP-01, at 13. APAC points out that until a contract with the DSIs is negotiated, these values for DSI reserves are uncertain. *Id.* at 14. In the meantime, APAC states, BPA must be conservative in setting those values, and given that there is no certainty regarding the contracts, the amount of reserves and their value should be set very low. *Id.* APAC states that BPA should not adopt the IOUs' proposal for a credit for reserves for which it has no estimate of value or willingness of the DSIs to accept less than value. *Id.*

BPA disagrees with APAC's assessment. As indicated above, the value of reserves credit is required to be set to account for the value of reserves provided by DSIs to satisfy the requirement that DSI sales "shall provide a portion of the Administrator's reserves for firm power loads within the region." 16 U.S.C. § 839c(d). Staff has proposed a reserve product to be provided for service under the IP rate that is very specific with respect to the parameters of the product to be provided. Staff has proposed the quantity that must be made available and has described the attendant conditions. The proposed value of reserves credit is based the value of this specific product. Any contracts for DSI service provided for the WP-10 rate period will be required to support the type and level of reserves required for sales under the IP rate. In other words, the Staff proposal has dealt with each of the three separate factors that APAC believes are required for proper calculation of the value of reserves credit. Contrary to APAC's stated position, neither the value of such reserves nor their availability for use to respond to various system events is "uncertain"; nor is it subject to contract negotiation.

A question remains regarding the level of IP service that DSIs will actually be taking during the course of the rate period. BPA determined, as stated in the Federal Register, that it would not take up issues pertaining to the level and type of service that may be offered to DSIs in this proceeding. BPA is conducting a separate process to deal with those issues. Thus, as noted above, BPA has included a forecast of the level of service that will ultimately be provided, and this forecast satisfies BPA's cost recovery and other ratemaking obligations. Obviously, forecasting errors do occur, but when actual contracts are not available, it is recognized that forecasting is a generally accepted ratemaking tool. IOU Br., WP-10-B-JP1-01, at 86.

Moreover, even if BPA had signed contracts in place for every DSI for the WP-10 rate period, that would in no way guarantee that a particular DSI would continue to operate for the entire rate period, or operate at the maximum levels contemplated in the contract. Thus, even with contracts in place, there would still be a possibility of error with regard to future operating levels.

Thus, BPA sees no basis for APAC's contention that the value of reserves should be established very low based simply on any uncertainty regarding the ultimate operating levels of any DSIs who receive service at the IP rate. Certainly, there is no statutory support for such a methodology. The statute requires that the "[t]he Administrator shall adjust such rates to take into account the *value of power system reserves made available* to the Administrator through his rights to interrupt or curtail service." 16 U.S.C. § 839e(c)(3) (emphasis added). BPA does not see a statutory basis for establishing the credit at less than the value of such reserves simply on the basis that the ratemaking process is subject to various uncertainties.

APAC clarifies that BPA should forecast a value of reserves, but BPA should be conservative in its estimate of such value of reserves. APAC Br. Ex., WP-10-R-AP-01, at 8, As stated above, that is exactly what BPA has done: calculate a value for a type and level of reserves that a DSI will be required to provide pursuant to the IP rate schedule, the GRSPs, and the contract itself. The value of reserves established and incorporated in the IP rate should be attainable by all DSIs and, further, the amount of reserves so valued should not exclude any DSI from purchasing from BPA because it cannot provide such amount of reserves. BPA believes that use of reserves based on 10 percent of the DSIs' load as the basis for establishing the value of such reserves is conservative and meets the statutory requirement that DSIs shall provide a portion of the Administrator's reserves for firm power loads within the region and that BPA shall adjust such rates to take into account the value of power system reserves.

PPC *et al.* argue that the highly speculative nature of DSI customers as a source of reserves does not warrant any reduction in the IP rate. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 6. PNGC believes that such a decision is inconsistent with sound business practices. PNGC Br. Ex., WP-10-R-PN-01, at 4. Such decision would allow the DSIs to benefit immediately from a large VOR credit before the physical means of providing the reserves is even put in place. *Id.*

While PPC *et al.* are correct that there are currently no fully developed DSI contracts in place for FY 2010-2011, the lack of effective contracts does not create any uncertainty about the value of reserves or the certainty of BPA being able to acquire reserves from DSIs at the 10 percent level included in the IP rate. In the past, BPA acquired reserves from DSIs at a 50 percent level. IOU Br., WP-10-B-JP1-01, at 71-72. Nor does the lack of an executory contract with DSIs pose a statutory barrier. First, BPA does not simply rely on Alcoa's representations about the reserves that it might be able to provide as the construct for reserves required under the IP rate. BPA considered Alcoa's testimony, its own analysis, and other documentation to create a reserve requirement that all three remaining DSIs should be able to provide.

The fact that there is no existing contract spelling out those requirements is irrelevant. The IP rate schedule is clear that sales under the IP rate are contingent on provision of reserves as defined in the GRSPs. The GRSPs is the document specifically defining the amount, duration, and other relevant features of the reserve requirement established in rates. If a DSI is unwilling or unable to accept the terms required by the IP rate, then there will be no contract and no sale at the IP rate. Thus, if and when BPA enters into an IP contract with a DSI, there will be no uncertainty with respect to the reserves BPA is entitled call upon. Similarly, there will be no uncertainty with respect to the value that the DSI will receive in return, because the value of the specified reserves has been calculated in the rate case and embedded in the IP rate as a value of reserves credit.

To the extent that BPA does not enter into IP contracts with the DSIs, there is still no uncertainty. With no contract in place, BPA can be certain that it will not have DSI-provided reserves at its disposal and, to the extent necessary, will make alternative arrangements. The DSIs will receive no compensation, because they would not be purchasing power under the IP rate and, consequently, they would be receiving no credit for reserves that are not being provided. Thus, none of the PPC *et al.* concerns about reserves has merit.

PNGC claims that its testimony has demonstrated that existing DSI facilities needed to be "enhanced" before they could provide balancing and regulation reserves; any specific required "enhancements" and their costs are unknown at this time; the terms and conditions on which "enhancements" would be constructed and made available are unknown; and BPA has conducted no studies or analysis to prove that DSIs are a least-cost, or even cost-effective, source of balancing or regulation reserves. PNGC Br. Ex., WP-10-R-PN-01, at 4. The PPC *et al.* and PNGC arguments are not relevant, because the reserves included in the value of reserve credit to the IP rate are not balancing or regulation reserves, which may require enhancements. Rather, they are supplemental operating reserves, which are not speculative and do not require enhancements by the DSIs or BPA and have been successfully called upon under past contracts and rates.

PPC *et al.* argue that BPA's treatment of this issue only serves to shift even more risk and increased costs to the agency's preference customers and does not comport with section 7(c)(3) of the Northwest Power Act. Section 7(c)(3) directs the Administrator to adjust the IP rate to take into account the value of reserves "made available to the Administrator *through his rights* to interrupt or curtail service to such direct service industrial customers." PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 6, emphasis in original. This argument is not valid. BPA's approach would not shift risk and increased costs to preference customers. By including the value of reserves in the IP rate, a DSI purchasing power at such IP rate is required to provide reserves in the amount that was used to establish the value of such reserves. Therefore, should BPA sell power to a DSI at the IP rate, BPA will be acquiring a specified amount of reserves in consideration for the rate credit. By requiring the DSI to provide the reserves in order to purchase at the IP rate, BPA will have acquired the reserves, such reserves will have been made available to the Administrator through his rights to interrupt or curtail service, and BPA will provide a rate credit to such DSIs reflecting the value of such reserves. 16 U.S.C. § 839e(c)(3). This construct fulfills the statutory mandates for the DSIs to provide a portion of BPA's reserves, as required by 16 U.S.C. § 839c(d).

PPC *et al.* contend that BPA's approach relies on an Alcoa representation that significant reserves could be provided by the DSIs, but there is no actual commitment to provide such reserves. *Id*. Given that it is clearly in the interest of Alcoa to have BPA assume a significant level of reserves, because such an assumption reduces the IP rate, and given that there is no obligation in place for Alcoa to actually provide such reserves, it is unreasonable for BPA to rely solely on those representations to change its position and assume a level of reserves significant enough to drastically reduce the IP rate. *Id*.

However, PPC has not accurately described BPA's proposal. As discussed below, BPA is not including the reserves that Alcoa states it may be able to provide. Speer, WP-10-E-AL-CC01, at 8-11; Alcoa Br., WP-10-B-AL-01, at 11. As BPA has explained above, to purchase at the IP rate, the DSI must commit to provide the amount of reserves embedded in the IP rate credit. BPA does not view the amount of reserves so provided as so large that they become speculative; nor is a rate credit granted for an amount of reserves that a DSI would actually provide.

PNGC speculates that BPA apparently intends to provide increased subsidies to its DSI customers by means of a dramatically increased VOR credit amount. PNGC Br. Ex., WP-10-R-PN-01, at 4. This speculation does not withstand the facts. The rate credit is larger than included in the Initial Proposal because the design of the reserves product that BPA is requiring of the DSIs is a more valuable product. In the Initial Proposal, Staff proposed a reserves product that would so constrain BPA's ability to use the product that it had a very small value. That product was limited to 60 minutes per use and a maximum of 4 uses per month, resulting in a derating of its value. Fisher *et al*., WP-10-E-BPA-30, at 8. In contrast, Staff revised the reserves product by recognizing that a DSI could provide up to 10 percent of its net load for up to 105 minutes one time each day, Fisher *et al*., WP-10-E-BPA-36, at 11. This more valuable product does not lead to derating the value as did the Initial Proposal product.

PNGC then concludes with an unsubstantiated claim that under present economic circumstances, a decision by BPA to use this device to reduce the IP rate while it is substantially increasing the PF rate is clearly inequitable. PNGC Br. Ex., WP-10-R-PN-01, at 4. BPA's rate directives represent numerous policy calls by Congress, including that the IP rate be tied to the PF rate and that DSIs be credited for the value of reserves made available to the Administrator. BPA is following the law, so disagrees with PNGC that its actions are inequitable.

The IOUs, in contrast to the preference customers, state that at a minimum, BPA should assume interruption rights similar to those contained in its 1981 or 1996 power sales contracts with the DSIs, which provided for operating reserves equal to one-half the total average forecast DSI load for the rate period, exclusive of wheel-turning load. IOU Br., WP-10-B-JP1-01, at 71-72. The IOUs state that BPA projects a total average forecast DSI load of approximately 402 aMW (including 6 aMW of wheel-turning load) for the rate period. *Id*. at 72. Therefore, the IOUs argue, BPA should assume, at a minimum, operating reserves equal to 198 MW, one-half of the non-wheel-turning load. *Id*. The IOUs add that, given BPA's concerns about a looming capacity deficit, the interruption rights should be greater than they were during the 1981-2001 period. *Id*. Using the unit rate of $7.19 per kW per month for Supplemental Operating Reserves proposed in the Initial Proposal to value these DSI load interruption rights, the IOUs calculate the minimum annual value of reserves provided by the DSIs as $17,083,440. *Id*. at 73. The IOUs argue that to the extent the interruption rights do not extend to the entire load, the value of reserves should be based on the portion of load subject to interruption rights, but the portion of interruption rights should be not less than half of the total average forecasted DSI load (exclusive of wheel-turning load) for the rate period. *Id*.

The IOUs argue that the record is devoid of information that supports the contention that only 10 percent of non-wheel-turning load is a maximum measure of the quantity of reserve available from a DSI power sale. *Id*. In that regard, no party has presented any evidence in this proceeding that demonstrates that the DSIs cannot provide interruption rights similar to those contained in BPA's 1981 or 1996 Power Sales Contracts with the DSIs (*i.e.*, at a minimum equal to half of the DSI load exclusive of wheel-turning load—198 MW). *Id*.

The IOU proposal is not sustainable. First, in spite of passage of decades during which the power market has been revolutionized and the Pacific Northwest metals industry has virtually collapsed, the IOUs maintain there is no need to revisit any of the past assumptions about the ability of smelters to provide reserves. Instead, BPA should just assume that DSIs are physically capable of providing the same quantity and type of reserves and establish the credit based on those criteria. BPA sees no basis for establishing the credit based on a product that a DSI might not ultimately be able to provide. This would lead to one of two results unintended by the relevant statutes: 1) a DSI could be overcompensated for the product it could actually provide, or 2) a DSI could be considered ineligible to purchase at the IP rate because it is physically not capable of providing the described service. BPA does not believe that Congress intended either result. The statute certainly does not envision the reserve requirement as being a means by which the BPA could effectively preclude IP service by requiring provision of reserve products that a DSI is unable to provide. Neither did the Congress intend that DSIs receive anything more or less than the "value" of the reserves being provided. In addition, while the statute required BPA's "initial" contracts with DSIs to provide an amount of power equivalent to earlier contracts, no such requirement pertains to later contracts, and BPA's election to provide less power than was made available under the initial 1981 contracts has obvious bearing on BPA's use of DSI reserves and the DSIs' ability to provide them.

Second, the IOUs simplify the many distinctions and complexities about the 50 percent reserves provided by DSIs under the 1981 contracts. Under those contracts, the DSI-provided both *energy* reserves and *capacity* reserves. The 1981 contract-provided reserves are explained thus:

> The Federal system reserves provided by the DSI restriction rights are separated into three parts: forced outage reserves, stability reserves and plant delay reserves. This separation follows the language and intent of Section (7) of the new DSI power sales contracts. Forced outage reserves (capacity and energy) maintain the operating integrity of the Federal system through the ability to restrict the DSI load. Stability reserves prevent regional and interregional instability resulting from underfrequency on the electrical grid through restricting the DSI load. Plant delay reserves protect the reliability of the system from construction delay and poor performance of existing plants through second quartile restriction rights.
>
> To avoid double counting reserves, the quartiles were categorized based on the reserves they predominately provide. Inherent in the pricing of the top quartile is

> the recognition of the available reserves associated with that quartile. That is, the application of the nonfirm rate in the pricing of the top quartile provides compensation for the reserves being provided. The second, third, and fourth quartiles provide both stability and forced outage reserves. However, since the fourth quartile only can be restricted for 15 minutes at any one time, this quartile was not assigned a value for forced outage reserves. Thus, only the second and third quartiles were valued for forced outage reserves.

WP-82 ROD, WP-82-A-02, at 99 (internal cites omitted). Comparing the 1981 contract-provided reserves to the reserves being contemplated in prospective contracts, stability reserves are now a transmission rate issue and plant delay reserves have not been discussed. The 1981 contracts provided forced outage reserves whereas the prospective contracts contemplate similar, but not identical, supplemental non-spinning reserves. Thus, the reserve products under the 1981 and the prospective contracts are different.

Third, the IOUs have provided no affirmative evidence to show that the DSIs are, in fact, capable of providing the level of reserves they recommend. They note only that no rate case party has provided evidence that the DSIs cannot provide the recommended level of reserves. However, the Northwest Power Act requires that the Administrator's rate determinations be supported by substantial evidence in the administrative record. The IOUs essentially rely on assumptions from previous contracts that were entered into in the 1980s and 1990s. Since that time, DSI load has decreased dramatically from several thousand to a few hundred megawatts. This huge reduction in DSI load could have an impact on the ability of the remaining DSIs to provide the level of reserves recommended by the IOUs. Another mitigating factor is that during the first contracts, DSI loads were generally operating at full capacity; in the instant case, BPA's assumption is that the DSIs will be operating about one-half capacity or less. The nature of the power operations in the Pacific Northwest have also changed dramatically, including the existence of more stringent requirements for the type of reserves that may be relied upon than existed in the 1981 contracts. In spite of these changes, the IOUs provide no analysis to show why its own assumptions remain valid.

Staff's proposal for the reserve credit does not suffer this infirmity. To set the IP rate, BPA adjusts the IP energy rates for reserves provided by interruption rights to the DSI loads, as required by the Northwest Power Act. Fisher *et al.*, WP-10-E-BPA-30, at 9; *see* 16 U.S.C § 839(c)(3). In addition, BPA must add costs related to the value of reserves in the 7(b)(2) Case, because reserves provided by the DSIs are not achieved in the 7(b)(2) Case. 16 U.S.C. § 839e(b)(2)(E)(ii).

During the WP-10 rate proceeding, Staff acquired more information that is useful in determining the value of DSI reserves. The first piece of information is the quantity (relative to the assumed size of an IP power sale) and limitations of the reserves, which were provided by Alcoa in Response to Data Request No. BPA-AL-01. Fisher *et al.*, WP-10-E-BPA-36, Exhibit 1. The second piece is methodological suggestions offered by Alcoa and the IOUs. Speer, WP-10-E-AL-01, at 8-11; LaBolle *et al.*, WP-10-E-JP1-01, at 5-20. The third piece is Staff's research into actual deployment of reserves. Fisher *et al.*, WP-10-E-BPA-36, Exhibit 2. The Response to Data Request No. BPA-AL-01 provides more information as to what the Alcoa smelter could actually provide as a reserve service. *Id.* at 20. While there is no signed contract that BPA can use to inform its estimate of the value of reserves provided by the DSIs, the information that is available, noted above, is enough to support a valuation that will establish a minimum requirement for any future contract negotiations. *Id*.

Thus, in contrast to the IOU proposal, Staff's proposal is based on affirmative evidence and reasoned analysis. Staff initially relied upon a contract term for provision of reserves that would have been provided under a contract with Alcoa had it ultimately been executed. Staff then directed a data request to Alcoa, requesting information on the level of reserves that it could provide, including confirmation that Alcoa would be able to provide the level of reserves proposed by Staff and adopted in this Record of Decision. In this manner, Staff tested the assumptions underlying previous contracts and provided affirmative evidence in the ratemaking record that supports BPA's decision.

While BPA disagrees with the IOU proposal, it should be noted that ultimately the value of the reserves being provided is calculated at the same total dollar level as proposed by the IOUs.

The IOUs are correct in stating that Staff recognizes that DSIs may provide reserves in addition to the above-described capacity reserves but does not propose to recognize that the value of any additional reserves in this proceeding. IOU Br., WP-10-B-JP1-01, at 76. It is also true that Alcoa proposes that it could provide Regulation, Capacity, Moderate Energy, and Large Energy Reserve products. Staff also provides evidence, in response to data requests, indicating that provision of such additional products was certainly not outside the realm of possibility and might even become possible prior to the close of the WP-10 rate period.

Nonetheless, BPA believes that Alcoa's proposal is somewhat speculative to include in the value of reserves for this rate proceeding. BPA's view of the evidence is that provision of these additional products might require certain modifications to the plant itself, or some investment in electrical equipment and/or infrastructure. Moreover, it is not clear if the other two DSIs, Columbia Falls Aluminum and Port Townsend Paper, are similarly situated so as to be able to provide the Alcoa-identified products. Given these uncertainties, BPA believes that it would not be prudent to attempt to determine a value for such services at this time and remains concerned that a credit in the IP rate that includes such products might provide a windfall to DSIs who might be unable to provide such products. In addition, incorporating Alcoa's proposed reserves into the rate schedule sets those reserves as the minimum required reserves to purchase power at the IP rate. Such inclusion may needlessly disqualify some or all of the DSIs from purchasing power until systems are in place to enable provision of the reserves.

While BPA will not recognize these products in the value of reserves credit, this does not mean that BPA is foreclosing any future opportunities to purchase products that provide value to BPA. The only point is that it would be inappropriate to recognize the value of such services at this time, given the existing uncertainties. If, at a later time, it is determined that such services can be provided based on a demonstrated need, then BPA would take further steps to determine if a satisfactory means could be found for delivery of and compensation for such services.

In their Brief on Exceptions, the IOUs take the opportunity to basically rehash the same arguments, with slightly more gloss attached. IOU Br. Ex., WP-10-R-JP1-01 at 15-19. The

IOUs state that Alcoa indicated that there were several additional products that Alcoa stated that it could provide. *Id*. at 15-16. The IOUs accuse BPA of engaging in a logical fallacy based on the argument that the statute requires that DSIs provide a *"portion"* of BPA's reserve requirements and arguing that BPA must recognize any reserves provided by DSIs in the value of reserves credit: "just because not all BPA reserves need be provided by DSIs does not establish that any DSI-provided reserves—that meet the statutory definition and that can be reasonably projected in BPA's rate proceeding—can be ignored in evaluating reserve benefits under section 7(b)(2) and in establishing a the IP rate value of reserves credit." *Id*. at 16-17. Moreover, the IOUs once again note that, historically, DSI loads have provided a greater amount and different types of reserves. *Id*. at 18.

BPA finds the IOU argument unpersuasive. First, the IOUs' misinterpret BPA's use of "portion." BPA has suggested only that the minimum reserve requirement adopted here provides a "portion" of the Administrator's reserve requirements. BPA has no intent to use the term in the manner suggested by the IOUs, *i.e.*, that BPA is only considering a "portion" of the reserves that Alcoa stated in testimony that it could provide. That said, BPA is not required purchase reserves simply on the basis that a DSI has maintained that it could provide additional reserves. To do so could result in crediting DSIs with a value for reserves that BPA either does not need or for reserves that are not all of the DSIs could provide. BPA has not ignored Alcoa's proposal. Instead, BPA believes that Alcoa's assessment of the kinds of reserves it can provide is overly optimistic and highly speculative at this time. Moreover, there has been no analysis to determine whether these reserves actually would provide real value to BPA. In short, despite the protestations of the IOUs and Alcoa, BPA will not include in the value of reserves credit reserves that are highly speculative and for which BPA has no present demonstrated need. As noted above, however, BPA will leave the door open to future consideration of such additional reserves being provided by DSIs that stand ready and able to deliver and for which BPA has a demonstrated need.

Decision

BPA has properly established the parameters for reserves required to be provided by DSIs pursuant to sales under the IP rate schedule.

Issue 3

Whether a share-the-savings approach should be used for calculating the value of DSI reserves.

Parties' Positions

The IOUs argue that BPA should adopt the share-the-savings approach when crediting the DSIs for the projected value of reserves in the same manner that BPA did in the 1983 and 1985 rate cases. IOU Br., WP-10-B-JP1-01, at 80. Under the share-the-savings approach, the IOUs would have BPA credit the DSIs with only one-half of the value of the reserves provided. *Id*.

BPA Staff's Position

BPA Staff believes that, in a competitive marketplace, sellers of reserve products, ancillary services, and other services have a reasonable expectation of being fully compensated, and buyers of such products should expect to pay full value for the product. Fisher *et al.*, WP-10-E-BPA-30, at 18. The value of such products should be based on market dynamics, uninfluenced by artificial interventions such as the "share the savings" approach. *Id*.

Evaluation of Positions

The IOUs argue that BPA should adopt the "share-the-savings" approach when crediting the DSIs for the projected value of reserves in the same manner that BPA did in the 1983 and 1985 rate cases. IOU Br., WP-10-B-JP1-01, at 80. Under the "share-the-savings" approach, the IOUs state, BPA would credit the DSIs with one-half of the value of the reserves provided. *Id*. The IOUs state that the Ninth Circuit has affirmed the Administrator's discretion to adopt the "share-the-savings" approach. *Id*., *citing Central Lincoln People's Util. Dist. v. Johnson*, 735 F.2d 1101, 1127 (9th Cir. 1984). The IOUs point out that prior to the 1996 rate case, BPA used, in effect, the "share-the-savings" approach to credit the DSIs with half of the projected value of reserves. IOU Br., WP-10-B-JP1-01, at 80. In the 1996 rate proceeding, BPA did not adopt the "share-the-savings" approach and instead credited the DSIs with all of the value of the reserves provided. *Id*. In doing so, the IOUs state, BPA determined that the failure to credit the DSIs with the full projected value of reserves would establish an IP rate that would have exceeded the market rate, and BPA could lose additional DSI load. *Id*.

The IOUs claim that BPA's rationale for the abandonment in the WP-96 rate proceeding of the "share-the-savings" approach is not persuasive for the FY 2010-2011 rate period. *Id*. at 81. In 1996, market prices were competitive with or below many BPA rates (including, without limitation, the IP rate), and many DSIs and preference customers were purchasing from the market instead of BPA. *Id*. In the WP-96 rate proceeding, BPA was concerned about loss of DSI load to competition, and BPA abandoned the "share-the-savings" approach to make the IP rate as close as possible to or below market rates. *Id*.

The IOUs claim that the environment discussed in the WP-96 ROD does not exist today. *Id*. at 82. The IOUs state that the IP rate is no longer near or above market prices, and the DSIs already receive the benefit of an IP rate that is lower than market rates. *Id*. The IOUs state that, as compared with BPA's proposal, recognizing additional projected DSI reserves, increasing the projected value of reserves to a reasonable level, and crediting the DSIs with half of such increased projected value of reserves (as the IOUs propose) would make the DSI rate even lower. *Id*.

BPA disagrees with the IOUs' assessment. In establishing a value of reserves in the 1983 and 1985 rate proceedings, BPA did adopt a "share-the-savings" approach, under which it credited the DSIs with only one-half of the value of the reserves they provided. In part, BPA justified the "share the savings" approach based on the argument that, because the DSIs are firm power customers, they benefit from the reserves that are provided to BPA and, as a consequence, they should share the value of the reserves with BPA's other customers. *Central Lincoln Peoples' Utility Dist. v. Johnson*, 735 F.2d 1101 (9th Cir. 1984) ("lowering the value of [the DSI] credit is appropriate because the DSIs are firm power customers who benefit from the reserve"). BPA also relied upon a report on the final version of the Northwest Power Act, wherein the Senate Committee on Energy and Natural Resources included a numerical analysis of BPA's ratemaking. That analysis assumed that, in its initial rate case, BPA would credit the DSIs with half of the value of reserves. The Committee then noted as follows:

> The crediting of 50 percent of the value of the reserves to the DSIs does not set a precedent for future BPA rate cases. The form of availability credit or other reserve credit mechanism to be applied is not meant to be specified or prejudiced by the assumptions that are here.

S. Rep. No. 272, 96th Cong., 1st Sess. 64 (1979). This legislative history clearly, by its own terms, cannot be relied upon for precedential value, and the Administrator's reliance on this statement when he originally adopted the share-the-savings methodology makes it clear that he was not setting a precedent for future rate cases. Neal *et al.*, WP-96-E-BPA-24, at 20; WP-96 Record of Decision, at 192. Even in the absence of such explicit disclaimers, it would be inappropriate for BPA to rely on such legislative history as the sole predicate for future decisions regarding the value of reserves credit.

From 1986 until 1996, the DSI industrial margin and VOR were set pursuant to the IP-PF Link. Under the Link, these rate adjustments were made through application of the Gross National Product deflator. *Id*. At that time, the "share the savings" approach was described as follows:

> The actual amount of the VOR credit to the DSIs is calculated using a share-the-savings concept. The sum of the alternative cost of providing system reserves and the costs of a restriction to the DSIs is divided by two.

1986 IP-PF Link Administrator's Record of Decision, March 1987, at 7. Conceptually, this approach differs from the approach adopted earlier. In 1983 and 1985, BPA had focused on idea that the DSIs, as firm power customers, benefit from BPA having those reserves at its disposal and should therefore be expected to share some part of the VOR credit with other customers. The IP-PF Link proposal, by contrast, seems to focus on any savings achieved by BPA by having access to DSI reserves instead of having to acquire some other resource in order provide the reserves. Thus, it is incorrect for the IOUs to assert that BPA's policies essentially remained unchanged for the entire period from 1983-1996. In fact, BPA's policy focus in the 1986 IP-PF Link ROD was on the savings achieved by the Administrator being able to rely on DSI interruption rights rather than acquiring alternative resources. In 1983 and 1985, BPA focused exclusively on the cited legislative history and the notion that the DSIs benefitted from the reserves they provided in support of the Administrator's reserve obligations.

In the 1996 rate proceeding, BPA proposed (and ultimately adopted) a policy of providing DSIs with 100 percent of the value of reserves through the VOR credit. At that time, the IOUs suggested that BPA should not change the share-the-savings methodology "absent legislative change" and argued that the new proposal contradicted all of BPA's rate determinations since 1983. WP-96 Record of Decision, at 192, *citing* Piro *et al.*, WP-96-E-GE/PL/PS-02, at 16. BPA rejected these arguments and credited the IP rate with the full value of power reserves. BPA cited a number of policy reasons for rejecting the "share the savings" approach.

Importantly, BPA reassessed its earlier view that the "share-the-savings" approach could be justified on the basis that DSIs benefit from the reserves. Instead, BPA determined that any benefit to the DSIs is only indirect in that BPA's customers benefit from reserves only to the extent that BPA benefits. WP-96 Record of Decision, at 193, *citing* Tr. 1148. BPA found that the true benefit of the reserves was in BPA's ability to meet its reserve obligation under Northwest Power Pool operating criteria. *Id*. at 1147-1148. Thus, in the case of reserves, it is the utility itself that benefits. WP-96 Record of Decision, at 193, *citing* Kreipe *et al*., WP-96-E-BPA-53, at 9-10.

BPA also recognized that the power market had changed dramatically since the 1980s and was governed by competitive forces. In the 1996 rate proceeding, BPA concluded that in a competitive environment a purchaser of services must expect to pay full value for those services. WP-96 Record of Decision, at 192, *citing* Neal *et al*., WP-96-E-BPA-24, at 20. These rationales remain viable today and BPA is adopting them in this rate proceeding.

At the same time, BPA agrees with the IOUs that other policy rationales noted in 1996 are not as compelling. For example, BPA discontinued the share-the-savings method in part because it no longer could expect to obtain the right to trip DSI load without paying full value for that right. If BPA credited the DSIs with only half of the reserves value, the IP rate would have been above competitive levels, and BPA could have expected to lose substantially more DSI load. WP-96 Record of Decision, at 192. At that time, continuing DSI load loss could have had serious negative consequences for BPA's revenue streams. This factor is not a problem today.

Moreover, continued loss of DSI load, at that time, could have required the increased cost of purchasing capacity resources to replace DSI reserves. Were BPA to lose the DSI load (as it could have been expected to do if it continued the share-the-savings approach), then BPA would have needed to obtain reserves through its least-cost alternatives. In this situation, BPA would have incurred the full cost of installing and maintaining those alternatives. Therefore, BPA appropriately compensated the DSIs by crediting them with the full value of the reserves they provide. This rationale is not compelling as today, in large part because DSI service is discretionary, not mandatory. Thus, BPA could avoid this issue simply by choosing not to serve DSI load, but BPA would then be limiting its options to potentially more costly sources of reserves.

In spite of changes that have rendered some of BPA's 1996 rationales less compelling now than they were then, there is still ample reason for continuing to abandon the share the savings approach. As noted above, in a competitive market, sellers should be able expect compensation at the full value of products and services being provided. Similarly, buyers should expect to pay the full market value for such products and services, based solely on fundamental market forces, not based on an artificial intrusion into the marketplace such as the "share the savings" model or the exercise of leverage based on the discretionary nature of the sale. Also, the fact that BPA no longer needs a lower IP rate in order for BPA to remain competitive provides little justification for BPA to reduce the ability of the DSIs to be competitive in their markets by effectively depriving them of 50 percent of the value of a product provided to BPA.

More importantly, BPA does not believe there is a compelling legal basis for continuation of the "share the savings" approach to establishing the value of reserves credit. First, the language of the Northwest Power Act does not require a 50 percent reduction in the value of reserves credit. The relevant provision states only that "[t]he Administrator shall adjust such rates [rates for DSI service] to take into account *the value of power system reserves made available to the Administrator* through his rights to interrupt or curtail service to such direct service industrial customers." 16 U.S.C. 839e(c)(2) (emphasis added). Because the statute does not explicitly require any reduction in the VOR credit, it is reasonable to conclude that the intent of Congress was ultimately to allow BPA to provide up to full value to the DSIs for provision of reserves. The words "to take into account" gives BPA discretion to establish the portion of the value of reserves to include in the IP rate. Thus, BPA sees no compelling legal basis for reversing the 1996 policy change to compensate DSIs for the full value of reserves.

It is true that the Ninth Circuit has upheld BPA's prior adoption of the share-the-savings methodology. *Central Lincoln People's Util. Dist. v. Johnson*, 735 F.2d 1101, 1127 (9th Cir. 1984). In *Central Lincoln*, however, the court did not hold that this methodology was required by the Northwest Power Act, or that another methodology would be inappropriate. Instead, it simply upheld BPA's exercise of discretion. *Id*. BPA believes that retention of the 1996 policy is based on a reasonable interpretation of relevant statutory provisions and similarly comports with standards of review applicable to BPA final actions.

Finally, Congress has made clear that the Northwest Power Act does not mandate the share-the-savings approach. As noted above, in its report on the final bill, the Senate Committee on Energy and Natural Resources included a numerical analysis of BPA's ratemaking. That analysis assumed that, in its initial rate case, BPA would credit the DSIs with half of the value of reserves. The Committee then noted as follows:

> The crediting of 50 percent of the value of the reserves to the DSIs does not set a precedent for future BPA rate cases. The form of availability credit or other reserve credit mechanism to be applied is not meant to be specified or prejudiced by the assumptions that are here.

S. Rep. No. 272, 96th Cong., 1st Sess. 64 (1979). Thus, the report is clear that the "share the savings" approach adopted in the 1980s was not a precedent that the Administrator is bound to follow as a legal matter. Having considered relevant policy and legal issues, BPA will continue the policy adopted in 1996 of compensating DSIs for the full value of provided reserves.

The IOUs resurrect the issue in their Brief on Exceptions, again without providing much in the way of new information or compelling argument. IOU Br. Ex., WP-10-R-JP1-01, at 20. The IOUs assert that in a competitive market DSIs could not expect to purchase power at the IP rate, which is based on the preference rate. *Id*. The IOUs argue that the amount of the value of reserves allocated to the DSIs is part of a statutory rate formula unrelated to the competitive market, and there is no reason to allocate to the DSIs 100 percent of the market value of the DSI reserve, any more than there is reason to set the IP rate based on market. *Id*.

The IOUs' position is unclear. If the IOUs are saying that BPA should arbitrarily reduce the value of reserves credit simply because BPA sells the DSIs power at the IP rate, then such arguments are misplaced. The IP rate is the statutorily prescribed rate under section 7(c). Part of the rate directive requires providing a credit for the value of the reserves provided by the DSIs. There is nothing in the statute to suggest that the value of reserves credit should be used by BPA to manipulate the base IP rate (essentially the PF rate plus the typical margin less the value of reserves) because of the perception of some parties that the IP rate is below the competitive market prices that the DSIs would pay if they were not paying the rate that is statutorily mandated. Such circumvention of congressional intent would clearly be unacceptable.

As for other assertions in the Brief on Exceptions, those have been adequately addressed already. It is true that many of the reasons adopted in 1996 for abandoning the "share the savings" approach are not as compelling today. *Id*. at 21. The simple facts, and those that are the most compelling, remain unchanged. The "share the savings approach" is an artifact of a bygone era for which no party to this proceeding has provided a statutory basis. Without such a basis, there is no sound reason to continue a practice which basically deprives the DSIs of half the value of the reserve product provided pursuant to their statutory obligation.

Decision

BPA will continue to adopt the policy established in 1996 and will compensate the DSIs for the full value of provided reserves.

14.9 Section 7(c)(2) Typical Margin

Issue 1

Whether the level of the 2007 typical margin should be adjusted by an inflation factor.

Parties' Positions

PPC *et al.* argue that BPA has not offered any rational justification for why BPA should not adjust the last typical margin for inflation. PPC *et al.*, WP-10-B-JP11-01, at 12. PPC *et al.* state that doing so would align BPA's typical margin determination with normal ratemaking practice, which assumes inflationary increases for future costs, and would likely result in BPA's determination of the typical margin being based on substantial evidence. *Id*. PPC *et al.* state that adjusting the typical margin from four years ago by inflation would support the conclusion that the typical margin represents what is typically charged by preference utilities. *Id*.

Alcoa argues that BPA should reject the adjustment to the typical margin and retain the \$0.57/MWh margin that was supported by substantial evidence. Alcoa Br. Ex., WP-10-R-AL-01, at 2. Alcoa first argues that increasing the typical margin for inflation fails to meet the statutory standard for calculating the typical margin. *Id*. at 2-4. Alcoa then argues that such a change is not based on "substantial evidence in the rulemaking record." *Id*. at 4-5. Alcoa argues that the proposition that the typical margin increases with inflation is not based on any evidence other than speculation. *Id*. at 5-6. Finally, Alcoa argues that should BPA adopt such an adjustment, it fails to place the burden of proof on the rate case participants who are in the best position to bear it. *Id*. at 6-8.

BPA Staff's Position

Given the essentially unprecedented economic conditions that exist at the present time, it would be difficult to make an informed decision regarding whether the typical margin should be inflated or deflated. Fisher *et al.*, WP-10-E-BPA-36, at 24-26. In addition, changes in the typical margin over the period since 1996 have been rather small, and Staff would expect any changes in the typical margin, up or down, since 2005 (the year in which the data was collected for the most recent typical margin study) to be similarly small. *Id*. at 26. Staff disagrees with parties' recommendation that the 2007 typical margin should be adjusted by an inflation factor. *Id*.

Evaluation of Positions

In their direct testimony, both PNGC and PPC *et al.* state that the 2007 typical margin proposed in this rate case is outdated and understates the size of the typical margin. Prescott *et al.*, WP-10-E-PN-01, at 5-7; O'Meara *et al.*, WP-10-E-JP7-1, at 5. These parties recommend that BPA should have either re-performed the typical margin study or adjusted the 2007 typical margin by an inflation factor. Prescott *et al.*, WP-10-E-PN-01, at 5-7; O'Meara *et al.*, WP-10-E-JP7-01, at 5.

After further consideration of this issue, and review of the arguments presented by PPC *et al.*, BPA concludes that, despite Staff's concern with the difficulty of predicting the direction of change due to unprecedented economic conditions, this factor is outweighed by BPA's desire to remain aligned with normal ratemaking practice, which assumes inflationary increases for future costs.

Furthermore, doing so would be consistent with BPA's practice in the 1980s when the IP-PF link was used in establishing the IP rate. The IP-PF link contained an inflation adjustment based on the latest available GNP implicit price deflator. The purpose of the inflation adjustment was to conform the currently effective rate link to price levels in future test periods. Diffely, BPA, IP-PF-86-E-BPA-01, at 9. BPA agrees with PNGC and PPC *et al.* that, due to the number of years that have elapsed since BPA last conducted a typical margin study, inflationary forces would most likely have caused an increase in the types of overhead costs included in the typical margin.

Prior to this WP-10 rate proceeding, BPA was unable to dedicate time and staff to conducting a new typical margin study. The combination of the WP-07 Supplemental proceeding ending in September and the timing of the *PNGC* opinion in December left no time for such an undertaking, which would have required extensive coordination with PPC in collecting the data and significant time and energy in reviewing the data for purposes of calculating the typical margin. PPC itself was fully involved in the WP-07 Supplemental proceeding. The fact that a new study was not feasible, however, does not relieve the Administrator of his duty to review the typical margin and to ensure that it is consistent with the statutory command that it 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)

It is reasonable to conclude that the industrial consumers of preference customers have experienced inflationary forces since the last typical margin study. It is also reasonable to conclude that such forces would affect such customers over a broad spectrum of costs, including costs associated with the typical margin. Finally, it is reasonable to conclude that using an appropriate adjustment mechanism will provide a reasonably accurate means of accounting for such increased costs without the substantial investment of time and resources needed to conduct a new typical margin study *de novo*. Adjusting the typical margin by an inflation factor causes a very modest increase in the IP rate, but such an adjustment is necessitated by the statutory requirement that the typical margin be equitable when compared to the margins paid by regional industrial consumers of preference utilities. As noted by PPC *et al.*, this approach is also consistent with generally accepted ratemaking principles, which presume increased future costs due to inflationary forces. Thus, the typical margin from the WP-07 rate case will be adjusted for inflation, aligning BPA's typical margin determination with normal ratemaking practice and statutory requirements governing development of the IP rate.

In its Brief on Exceptions, Alcoa has raised a number of objections to the draft decision. First, Alcoa argues that an adjustment for inflation is inconsistent with section 7(c)(2) of the Northwest Power Act, which lists a number of factors to be considered by the Administrator in developing the IP rate, including 1) the comparative size and character of the loads served, 2) the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions, and 3) direct and indirect overhead costs; all as related to the delivery of power to industrial consumers. Alcoa Br. Ex., WP-10-R-AL-01 at 2-3, *citing* 16 U.S.C. § 839(c)(2). Alcoa argues that the test is not discretionary and that BPA has failed to meet the legal standard for determination of the typical margin, primarily because there is no evidence in the record that the margins to industrial consumers of publicly owned utilities have been increased since the typical margin was last developed by BPA based on the actual survey of margins to industries. *Id.* at 2.

Alcoa then goes on to cite some of the testimony that does bear on the issue of whether there should be an adjustment for inflation: Prescott *et al.*, WP-10-E-PN-01, at 5-7; O'Meara *et al.*, WP-10-E-JP7-01, at 6-7. Thus, by Alcoa's own admission, the record is not devoid of testimony related to this issue. Other parties have essentially pointed out that it has been a number of years since BPA has updated its data; that preference customers have, like everyone else, experienced inflation during that period; and that it would be reasonable at least to update the typical margin to account for that inflation. It is unclear why Alcoa believes such common sense observations are not "competent" for the purposes of this hearing. Alcoa Br. Ex., WP-10-R-AL-01, at 3. BPA does not believe that some sort of economic study is indicated for the purpose of showing that inflation has occurred. The real question is whether inflation has affected the typical margin and, if so, what standard should be used to account for such effect in the absence of a specific study. For such purpose, there is substantial record evidence to conclude that an adjustment should be made based on the GNP implicit price deflator.

Neither is BPA's decision to include an inflation adjustment deficient because it fails to take account of every criterion listed in section 7(c)(2). All such criteria were considered the last time BPA conducted a typical margin study. To that extent, such criteria are still embedded in the typical margin calculation. The only difference is that, in the absence of an updated study, BPA has decided to take account of inflation, which certainly qualifies as an "indirect cost" under section 7(c)(2). The Administrator's decision, then, is consistent with statutory directives.

Alcoa then goes on to suggest that ICNU acted improperly by not providing information relevant to the typical margin calculation in response to Alcoa's data request, stating that ICNU refused Alcoa's data request for actual evidence of any data supporting such assertions of increases in typical margins. *Id*. at 4. This allegation is misleading at best. Alcoa itself notes that its data request would have required "the power bills of ICNU's members in order to verify its flimsy evidence." *Id*. at 7, *citing* Response to Data Request No. AL-JP7-3. ICNU objected to the request and, subject to that objection, stated that it had no documents responsive to the request. Alcoa did not file a motion to compel and, by failing to do so, essentially acquiesced to ICNU's response. Moreover, even if the requested information had been produced, it is not clear to BPA how power bills would aid in calculating the typical margin. When conducting a margin survey, BPA routinely relies primarily on COSAs, or COSA-like information, from preference utilities to determine which costs are allocable to the typical margin and which are not. Utility bills would not provide this type of information.

Alcoa then attacks the inflation adjustment as not being based on substantial evidence. *Id*. at 4. Alcoa argues that BPA may not "assume inflationary increases" in the absence of substantial evidence in the rulemaking record considered as a whole that allows the Administrator to make a "determination" in applying the specific statutory standards in section 7(c)(2) of the Northwest Power Act. *Id*. at 5. Alcoa maintains that such an assumption about inflation does not meet that standard. *Id*. Alcoa's proposed standards for making this determination go well beyond the straightforward unembellished definition of "substantial evidence" proffered by PPC *et al.* in their Initial Brief: the "substantial evidence" standard requires that the Administrator's decision be based on "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." PPC *et al.* Br., WP-10-B-JP11-01, at 11, *citing Consolidated Edison Co. v. NLRB*, 305 U.S. 197, 229 (1938).

Thus, the standard is a flexible one, requiring issue-by-issue application, not the straightjacket that Alcoa seems to impose. The question in this instance is whether it would be reasonable, based on the testimony in the record, to conclude that, during the period since the last typical margin study was conducted, inflation has affected the margins of retail industrial consumers. The answer is "yes." Would it be reasonable for the Administrator, therefore, to conclude that an inflation adjustment is consistent with his consideration of "indirect costs" pursuant to section 7(c)(2) and his obligation to establish a typical margin that is "equitable in relation to" the margins experienced by the industrial consumers of preference utilities? Again, the answer is "yes."

As Alcoa notes, Staff struggled with this issue, declining to include an inflation adjustment. Alcoa Br. Ex., WP-10-R-AL-01, at 5-6. Staff's concerns largely centered on the present downturn in the economy and the difficulty of determining, in such an environment, whether the current trend is inflationary or deflationary, and whether utilities would pass increased costs on to their retail industrial consumers. Ultimately, however, BPA considered the fact that the majority of the time that has elapsed since the last typical margin study was conducted occurred during more economically robust times, and so, on balance, it would be reasonable to rely on the

GNP deflator as a surrogate for the absence of an updated study. Taking that into account, BPA adopts PPC *et al.*'s position but rejects PNGC's testimony, Prescott *et al.*, WP-10-E-PN-01, at 6-7, that BPA adopt the Handy-Whitman Index of Public Utility Construction Costs. The Handy-Whitman Index would be a less-accurate measure of inflationary forces on the types of costs associated with the typical margin. Fisher *et al.*, WP-10-E-BPA-36, at 25-26.

Instead, BPA determines that it will rely on the GNP implicit price deflator index. In large part, this decision is based on BPA's reliance on that mechanism as a vehicle for adjusting the typical margin and the value of reserves credit in the past. 1986 IP-PF Rate Link ROD, IP-PF-86-A-02. At that time, the Administrator made the following determination:

> The GNP implicit price deflators are estimates of the amount of annual inf1ation forecasted to occur throughout the economy. They frequently are used to adjust for inflation effects when making cost comparisons between different years. Use of the GNP implicit price deflators is consistent with the escalation rates generally used for the program estimates in BPA's rate proposals. The GNP deflator index is preferable to other inflation measures for the purpose of the IP-PF rate link because it is easy to use and is readily available. Further, it is a generally accepted measure of inflation over time.

Id. at 8, *citing* Diffely, IP-PF-E-BPA-01, at 12.

The Administrator went on to describe the purpose of using the GNP implicit price deflator instead of performing a typical margin study during the approximately 10 years that the IP-PF link was in effect:

> BPA is establishing the IP-PF rate 1ink as a long-term ratemaking methodology to achieve greater load planning certainty by providing the DSIs with improved rate predictability and to reduce the controversy and need for data collection in future BPA rate cases.

Id. at 9, *citing* Diffely, IP-PF-E-BPA-01, at 2-4. Thus, BPA's rationale for adjusting the typical margin based on the GNP implicit price deflator has equal force today. Due to the difficulty in collecting data for a complete typical margin study, the deflator serves as an acceptable surrogate. It should be noted that, at that time, the DSIs supported BPA's use of the GNP deflator. *Id.*

Finally, Alcoa argues that BPA's draft decision is defective because BPA has failed to place the burden of proof on those who are seeking the adjustment. Alcoa Br. Ex., WP-10-R-AL-01, at 6-8. Essentially, Alcoa argues that the preference customers and their industrial consumers are in possession of the information that would allow BPA to conduct a typical margin study, and so the burden of proof should be on them to show that an inflation adjustment is necessary. *Id.* As indicated above, BPA believes that the inflation adjustment comports with all legal requirements. However, the peccancy for failing to conduct a new typical margin study falls on BPA, not on the preference customers and their industrial consumers. Thus, the consequences of any decision not to obtain information needed to conduct a typical margin study rests with BPA. In such a situation, the Administrator will not impose any additional evidentiary burdens on the parties advocating an inflation adjustment. Such a determination would be the equally heavyhanded equivalent of declaring that Alcoa is judicially estopped from objecting to use of the GNP deflator now on the basis that the DSIs previously supported use of the deflator, as noted above, in 1987 during the IP-PF Link proceedings.

Therefore, the typical margin used in the WP-07 rate case will be adjusted for inflation, thus aligning BPA's typical margin determinati., the PF preference rate) and the "typical margins" that are to be included in the IP rate.

Decision

BPA will adjust its most recent typical margin by an inflation factor, using the GDP Implicit Price Deflator. Accordingly, the typical margin used in calculating the IP rate for this rate case is 0.63 mills/kWh.

Issue 2

Whether revenue taxes should be included in the typical margin.

Parties' Position

PPC *et al.* argue that BPA should include revenue taxes in the typical margin. PPC *et al.* Br., WP-10-B-JP11-01, at 12.

BPA Staff Position

BPA should retain the policy established in 1996 and not include revenue taxes in the typical margin. Fisher *et al.*, WP-10-E-BPA-36, at 27.

Evaluation of Positions

PPC *et al.* argue that BPA's typical margin should include Washington state revenue taxes, because these taxes are included in the margins charged by Washington public utilities to their industrial consumers, and the majority of publics' load, as well as DSI load, is in the state of Washington. PPC *et al.* Br., WP-10-B-JP11-01, at 12. PPC *et al.* argue that BPA's methodology for establishing the typical margin is overly simplistic and fails to take into account the purpose of the typical margin. *Id*. at 13. That purpose, according to PPC *et al.*, is to establish an adder to the DSIs' rates so that their rates have a "relation to the retail rates charged by the public body and cooperative customers" to their industrial consumers. *Id*., *citing* 16 U.S.C. § 839e(c)(1)(B). PPC *et al.* state that the typical margin should, therefore, be a margin charged to the DSIs that represents the margins the DSIs might have paid as industrial consumers of preference customers. PPC *et al.* Br., WP-10-B-JP11-01, at 12. Therefore, PPC *et al.* conclude, the location of the DSIs and the typical margins that are charged in that state could and should be a relevant factor in determining the appropriate typical margin to add to the DSIs' rates. *Id*.

Since 1996, BPA has concluded that revenue taxes are not typical, as intended by the statutory directive that requires that the BPA rate applicable to DSI sales "shall be based upon the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates." WP-10-E-BPA-36 at 27, *citing* 16 U.S.C. § 839e(c)(2); WP-96 Wholesale Power Rate ROD, WP-96-A-02, at 180.

PPC *et al.* misconstrue the statutory directive for determining the typical margin that applies to the IP rate. Section 7(c)(1)(B) of the Northwest Power Act provides that the rate for service to DSIs for the period beginning July 1, 1985, shall be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers *in the region*." 16 U.S.C. § 839e(c)(1)(B). Thus, the statute makes clear from the outset that the rate determination should be based on a regional view of equitability, not one that is state-specific. The statute goes on to say, more specifically, that "[t]he determination under paragraph (1)(B) of this subsection shall be based upon the Administrator's applicable wholesale rate to such public body and cooperative customers and the typical margins included by such public body and cooperative customer in their retail industrial rates." 16 U.S.C. § 839e(c)(2).

Thus, the explicit language of the statute makes it clear that, when BPA calculates the "typical margin," it must assess the "typical margins" that are charged by all of BPA's public body and cooperative customers to their industrial consumers, not some select group. The location of the DSI facilities themselves is not mentioned in the statute. Thus, it is reasonable to conclude that Congress's command to create an IP rate that is "equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers *in the region*" applies both to the applicable wholesale rate (*i.e.*, the PF preference rate) and the "typical margins" that are to be included in the IP rate.

This interpretation is consistent with BPA's practices since 1996. WP-96 ROD, at 160. There, the Administrator found as follows:

> Section 7(c)(2) provides that the determination under section 7(c)(1)(B) shall be based on BPA's applicable wholesale rates to its public body and cooperative customers "and the typical margins included by such public body and cooperative customers in their retail industrial rates." *Id.*, 16 U.S.C. § 839e(c)(2). BPA asserts that revenue taxes are not a component of the typical industrial margin because a majority of BPA's preference customers with industrial [consumers] do not pay revenue taxes, and therefore the majority do not include revenue taxes in their retail industrial rates.

Id. at 160. In reaching this conclusion, BPA undertook an analysis of what is meant by a "typical" margin and based the final determination on that analysis. BPA derived the meaning of typical as follows:

> "Typical" means "representative of a whole group"; The American Heritage Dictionary of the English Language 1388 (1976); "serving as a characteristic example"; "representative." New Shorter Oxford English Dictionary 3442 (1993). If a given trait is peculiar only to a minority of a population, it cannot be said to be either "representative of [the] whole group" or "a characteristic example." If anything, the opposite is the case: the absence of the trait is representative and characteristic. Therefore, if only a minority of utilities include

> revenue taxes in their margins, then such taxes are not a component of the typical industrial margin.

Id. at 178. BPA then applied this analysis to data available in the WP-96 rate proceeding record:

> BPA has 81 public utility customers that have retail industrial loads. Chang, Cocks, [WP-96-]E-BPA-54, at 6. Of these, 34 are in Washington, and therefore are subject to revenue taxes, and 44 are located elsewhere, and therefore do not pay revenue taxes. *Id*. at 6 and Attachments A and B. (BPA was unable to determine the customer classes for three of its public body customers. All of these customers, however, are located outside of Washington, and therefore are not subject to revenue taxes. *Id*. at 7.) Moreover, as APAC indicated, revenue taxes are paid in only one of seven states served by BPA. Wolverton, [WP-96-]E-PA-01, at 11. Therefore, they are not representative of the region as a whole. *Given this evidence, it can hardly be said that the payment of revenue taxes (and their inclusion in industrial margins) is typical; to the contrary, if anything it is typical for a utility not to include revenue taxes in its margin*.

Id. (emphasis added.) BPA also concluded:

> BPA is not suggesting that a cost must be incurred by all utilities, or in every jurisdiction, to be included in the margin. Indeed, such an argument would be as unconvincing today as it was in 1985. A cost need not appear in every utility's industrial rate to be typical of the class; the statute's use of the word "typical" rather than, for example, "universal" belies this approach. When a cost appears in only a minority of utilities' industrial rates, however, and when that minority is concentrated in only one state in the region, the cost is neither universal nor typical, and should be excluded from the margin.

Id. at 185. The issue was raised again in the WP-02 rate proceeding. As noted in Staff's rebuttal testimony:

> During the 2002 rate case, BPA focused on the issue of whether revenue taxes were or were not "typical." Rate case parties introduced tax statutes from Oregon and Idaho, arguing that such taxes were the equivalent of revenue taxes; therefore, they concluded, revenue taxes were indeed typical with respect to utilities serving industrial load in BPA's service territory. In the 2002 rate case ROD, BPA responded by doing a comprehensive analysis of the statutory provisions, concluding that the taxes identified by the parties were not revenue taxes, and Washington was the only state in the region that levied a revenue tax.

Fisher *et al.*, WP-10-E-BPA-36, at 27, *citing* WP-02 Wholesale Power Rate ROD, WP-02-A-02, at 15-3 – 15-15.

At that time, parties once again challenged BPA's methodology and argued, as they had in 1996, that BPA should revert to the decision made in 1985, which included revenue taxes in the typical margin:

> The IOUs argue that BPA's witness did not make any independent analysis regarding the issue of "whether government-owned utilities and cooperatives typically pay taxes based on gross receipts from the sale of electric power and

> whether such taxes should be included in the 'typical retail margin'." *Id*. at 28; *see also* PGE Brief, WP-02-B-GE-01, at 9.

WP-02 ROD, WP-02-A-02, at 15-3.

PPC supported the IOU position, at least in part:

> PPC makes a similar argument, asserting that perhaps as many as 29 utilities in Oregon pay franchise fees and in-lieu taxes, and claiming that BPA should have investigated the issue further based on IOU testimony that "a few telephone calls" had shown that Oregon jurisdictions charge revenue taxes. PPC Brief, WP-02-B-PP-01, at 58-59, *citing* Hoff *et al.*,WP-02-E-AC/GE/IP/MP/PL/PS-03, at 19.

BPA once again rejected this line of argument and determined that revenue taxes are not includable in the typical margin:

> BPA's analysis of whether revenue taxes should be included in the margin considered both: (1) the number of utilities serving industrial load and subject to a revenue tax; and (2) the number of states within BPA's service territory which levy a revenue tax. Ebberts, WP-02-E-BPA-47, at 6. Based on those parameters, BPA concluded that, for purposes of calculating the industrial margin, only the state of Washington levies a gross revenue tax. *Id*. This means that revenue taxes are typical neither of the states within BPA's service territory nor among BPA's customers serving industrial load. *Id*. Therefore, revenue taxes are not "typical" as contemplated by section 7(c)(2) of the Northwest Power Act and should be excluded from the margin. *Id*.

WP-02 ROD, WP-02-A-02, at 15-5. In responding to the question of how many states within BPA's service territory levy a revenue tax, BPA analyzed the various taxes that parties argued were the equivalent of revenue taxes; the parties argued also that BPA should consider them as such, and should then reach the conclusion that a majority of the states in BPA's service territory levy revenue taxes.

BPA's analysis showed that the identified taxes were not revenue taxes and were thus not includable in the typical margin. First, BPA analyzed the Washington state revenue tax, concluding as follows:

> The essential features of the Washington revenue tax, then, can be described as follows: (1) it is a comprehensive tax, imposed solely for revenue purposes; (2) it is levied and administered at the state jurisdictional level; (3) it is a tax on "gross income," defined broadly; and (4) it is not a license fee, regulatory tax, or occupation tax.

Id. at 15-9. BPA then analyzed the other taxes being promoted as revenue taxes.

First, BPA examined ORS chapter 308, which the IOUs had characterized as the equivalent of a revenue tax, and found that the Oregon tax was not analogous to the Washington revenue tax:

> First, it is not a revenue tax at all, but rather a property tax. As the Supreme Court of Oregon has held:

> > ORS chapter 308 deals with valuation of various types of property for property tax purposes. ORS 308.805 through 308.820 deal with a specific type of property (electrical distribution systems) owned by a specific class of taxpayers (non-profit electric cooperatives). ORS 308.805 provides a method of taxing such property different from the usual ad valorem method based on assessed value. Although the tax is measured by gross revenue, the tax is more properly considered a property tax than an income tax.
>
> *Lane Electric Cooperative v. Department of Revenue*, 765 P.2d 1237, 1239 (1988).
>
> While the holding of the Oregon Supreme Court is not binding on the Administrator for purposes of interpreting section 7(c)(2), the description clearly comports with the statutory language, and the Administrator finds it persuasive with regard to the character of the tax. Moreover, the court's interpretation is supported by the fact that the income basis for the tax applies only if the tax owed is less than the tax would be if based on the market value of the property itself. Thus, the tax embodied in ORS chapter 308 is not a revenue tax, but a property tax. Moreover, the Oregon tax differs in other material respects from the tax imposed by the state of Washington. First, it is not a comprehensive tax at the state level; instead, it is specifically targeted at a very limited classification of taxpayers and is earmarked for use by the county for specific purposes. Second, because the funds are distributed to the county governments, the tax is not wholly administered at the state level. Third, even if it could be characterized as an income tax, the Oregon tax is not a tax on "gross income," but a tax on income derived from a specific and limited type of property. For purposes of calculating the margin, two taxes of a completely different character cannot simply be lumped together and treated as though they are the same thing.

Id. at 15-9 – 15-10.

BPA similarly found that the Idaho statute promoted by the IOUs for "revenue tax" treatment was not, in fact, a revenue tax:

> The IOUs' reliance on Idaho's statute, IC 63 3502, is similarly misplaced. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 38. That tax applies to any "Cooperative Electrical Association," defined as "any nonprofit, cooperative association organized and maintained by its members, whether incorporated or unincorporated, for the purpose of transmitting, distributing or delivering electric power to its members." IC 63 3501. The tax is computed at a rate of 3.5 percent on gross earnings after deducting that figure by its costs of power and certain Energy Northwest costs. IC 63 35 02. Moreover, payment of the tax is deemed to be inlieu of all other property taxes. Thus, it is very similar to the Oregon tax and for the same reasons, it is a property tax rather than a revenue tax. As the DSIs correctly note:
>
> > Many of the utilities that assess taxes that might be called 'revenue taxes' in reality collect taxes in lieu of property taxes. Property taxes are

> appropriately assigned to the production, transmission, and distribution categories in the margin study, depending upon the taxable property upon which they are levied. These in lieu taxes are not revenue taxes of the kind that is levied by utilities located in the State of Washington.

Id. at 15-10, *citing* DSI Brief, WP-02-B-DS-01, at 30.

BPA also analyzed franchise fees authorized under ORS §221.420, §225.270, and §225.270 and found similarly that such taxes are not revenue taxes. WP-02 ROD, WP-02-A-02, at 15-10 – 15-11.

BPA's comprehensive analysis of the tax statutes has not been challenged in this proceeding. Therefore, revenue taxes are not typical within the states that comprise BPA's service territory. Neither are they typical among BPA's preference customers who serve industrial load. Revenue taxes have to be "typical" within the entire region served by BPA, and not just a feature of a single state within the region; revenue taxes are not typical on that basis.

Thus, as stated in the 2002 ROD:

> Because BPA's conclusion regarding which jurisdictions levy revenue taxes is correct, it follows that the only factual determination necessary is whether, at a minimum, a majority of the Administrator's public agency customers serving industrial load are subject to Washington's revenue tax. BPA's witness provided this information in direct testimony and furnished updated numbers in rebuttal, *concluding that 32 utilities serving industrial load are in Washington, and 51 are located elsewhere*. Ebberts, WP-02-E-BPA-22, at 8; Ebberts, WP-02-E-BPA-47, at 7.

Id. at 15-12. This factual evidence has not been challenged in this proceeding, and BPA will continue to rely upon it.

As can readily be seen, PPC *et al.* have not established a basis for their claim that BPA's analysis is, and has been, "overly simplistic and fails to take into account the purpose of the [typical] margin." In fact, the evidence shows that BPA's analysis has been comprehensive, if not exhaustive, in addressing various arguments made in favor of inclusion of revenue taxes in the typical margin. The PPC *et al.* analysis fails to take into account the purpose of the typical margin as explicitly set forth in section 7(c) of the Northwest Power Act by relying on the assumption that the location of DSI facilities is relevant. It is not. The statute clearly provides that the rate made available to DSIs must be "equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers *in the region*."

Since 1996, BPA has adhered to that standard, and it sees no reason to reverse course.

Decision

Revenue taxes will not be included in the typical margin.

15.0 LOOKBACK RECOVERY AND RETURN

15.1 Introduction

The "Lookback" is a construct BPA established in response to two decisions issued in May 2007 by the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit). In *Portland General Elec. Co. v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007) (*PGE*), the Ninth Circuit held that the 2000 Residential Exchange Program Settlement Agreements (REP Settlement Agreements) executed by BPA and the IOUs were inconsistent with the Northwest Power Act. In a companion case, *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037 (9th Cir. 2007) (*Golden NW*), the Ninth Circuit remanded the WP-02 power rates to BPA on the grounds that BPA improperly allocated the costs of the REP Settlement Agreements, as amended, to BPA's preference customers. Although the Ninth Circuit's decision in *Golden NW* addressed only the WP-02 rates, the WP-07 wholesale power rates were implicated by the decisions because they contained the same infirmity identified by the Ninth Circuit. Evans *et al.*, WP-10-E-BPA-19, at 2-3.

To respond to the Ninth Circuit's decisions, BPA revisited its WP-02 and WP-07 rate case assumptions through a comprehensive "Lookback" construct. As explained fully in the 2007 Supplemental Wholesale Power Rate Proceeding Administrator's Final Record of Decision (WP-07 Supplemental ROD), the Lookback construct compared the amounts paid under the REP Settlement Agreements for FY 2002-2008 with the amounts BPA would likely have paid qualifying IOUs under the traditional operation of the REP. *Id.* The difference between these two amounts, subject to certain specified rules, is generally referred to as the "Lookback Amount." *Id.*; *see also* FY 2002-2008 Lookback Study, WP-07-FS-BPA-08, chapters 13-15. The total Lookback Amount is composed of six IOU-specific Lookback Amounts. Evans *et al.*, WP-10-E-BPA-19, at 3. The Lookback Amount will be recovered from the IOUs over time through reductions in future REP benefits and returned to the eligible consumer-owned utilities (COUs), with interest, as credits on their power bills. *Id.*; *see also* WP-07 Supplemental ROD (Conformed), WP-07-A-05, Chapter 9. Evans *et al.*, WP-10-E-BPA-19, at 2-3.

BPA's overall approach to recovering and returning the Lookback Amount was established in the WP-07 Supplemental ROD, in which BPA determined that the portion of each IOU's Lookback Amount to be recovered and returned to the COUs would be decided in each subsequent rate case. *See* WP-07 Supplemental ROD, WP-07-A-05, section 9.3.2. In reaching this decision, BPA relied upon the policy guidelines set forth in Bliven *et al.*, WP-07-E-BPA-52, at 11-25, and Forman *et al.*, WP-07-E-BPA-76, at 95-125. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 263-276.

As discussed in the WP-07 Supplemental ROD, the Lookback Amount must be recovered and returned in a manner that balances the need to provide a full and timely remedy to the COUs for the overcharges they incurred with the impact of such recovery on the IOUs' residential and small farm customers. *See* WP-07 Supplemental ROD (Conformed), WP-07-A-05, section 9.3.2. Generally speaking, the WP-07 Supplemental ROD established that, in meeting these objectives, BPA would return the Lookback Amount within a reasonable timeframe to the preference customers who incurred the overcharges, while also providing a reasonable level of lawful REP benefits to the residential and small farm consumers of the IOUs. *Id*. More specifically, the WP-07 Supplemental ROD established that these objectives would be met through a goal of returning the Lookback Amount within seven years, provided that the amount of REP benefits for any IOU would not fall below 50 percent. *Id*. at 266. The 50 percent threshold is to be reevaluated in each subsequent rate case. *Id*.

The total amount of overcharges incurred by the COUs for FY 2002-2008 is $985 million. Lookback Recovery and Return Study, WP-10-FS-BPA-07, at Table 1. BPA is on pace to return $424 million of these overcharges by the end of FY 2009. *Id*. at Table 2. An additional $163 million will be returned during FY 2010-2011. *Id*. at Table 5. At this point, as of the end of FY 2011, BPA will have returned $587 million in refunds to preference customers, including interest. Under BPA's simple assumptions regarding future REP benefits, $911 million is projected to be returned to the publics by the end of FY 2015. Also, by FY 2015, three utilities, Northwestern, Puget, and PGE, will have completely satisfied their Lookback obligations. PacifiCorp is projected to pay off its Lookback obligation in FY 2018, an additional three years, and Avista is projected to need until FY 2023, or an additional eight years.

BPA's goal in this rate proceeding is to continue to meet these policy objectives as established in the WP-07 Supplemental ROD. Evans *et al.*, WP-10-E-BPA-19, at 3-4. Consequently, in this case, BPA must decide the amount of Lookback to recover from the IOUs and return to the COUs in FY 2010-2011. Critical to this determination are the policies and criteria identified in Bliven *et al.*, WP-07-E-BPA-52, at 11-25; Forman *et al.*, WP-07-E-BPA-76, at 95-125; and the WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 263-276. The purpose of this chapter is to discuss BPA's decisions regarding the recovery and return of Lookback Amounts for FY 2010-2011.

15.2 <u>Consistency with the WP-07 Supplemental ROD</u>

<u>Issue 1</u>

Whether BPA's proposal for recovering and returning Lookback Amounts for FY 2010-2011 is consistent with the decisions made in the WP-07 Supplemental ROD.

<u>Parties' Positions</u>

APAC, WPAG, and PPC *et al.* generally object to Staff's proposed plan for recovering and returning the Lookback Amount for FY 2010-2011. APAC Br., WP-10-B-AP-01, at 5-8; WPAG Br., WP-10-B-WG-01, at 15-18; PPC *et al.* Br., WP-10-B-JP11-01, at 24-26; APAC Br. Ex., WP-10-R-AP-01, at 6-8; WPAG Br. Ex., WP-10-R-WG-01, at 11-14, 17-19. These parties generally argue that BPA's proposal is inconsistent with the assurances the Administrator allegedly made in the WP-07 Supplemental ROD.

For example, APAC contends that Staff's proposal to continue the application of the 50 percent threshold for REP benefits paid to Avista and PacifiCorp detracts from the necessary sense of certainty required of any plan for recovery and return of the Lookback Amount. APAC Br., WP-10-B-AP-01, at 5-9. APAC repeats its position in its Brief on Exceptions, stating that the Administrator should honor his commitment in the WP-07 Supplemental ROD and use his flexibility to accelerate the repayment of Avista's and PacifiCorp's Lookback Amounts, as well as to commence a process to recover overpayments from Idaho Power. APAC Br. Ex., WP-10-R-AP-01, at 6-8. WPAG states that BPA is abandoning its objective of repaying the entire Lookback Amount within seven years. WPAG Br., WP-10-B-WG-01, at 15-18. In its Brief on Exceptions, WPAG again claims that BPA has inappropriately placed payments to the IOUs above the return of overcharges to the preference customers. WPAG Br. Ex., WP-10-R-WG-01, at 17-18. WPAG continues to state that BPA has abandoned compliance with its own seven year "requirement" and directs BPA not to extend the repayment period for PacifiCorp and Avista, or suffer legal action. *Id*. at 18-19.

PPC *et al.* state that the repayment of the Lookback Amount should occur within exactly seven years, presumably for all of the IOUs. PPC *et al.* Br., WP-10-B-JP11-01, at 24-25. They object to an extension beyond seven years because seven years represents a remedy that is somewhat tailored to the harm preference customers experienced. *Id*. APAC also states that the lengthening of the projected amortization period for the Lookback Amount is inappropriate and indicates that BPA intends to put payments of REP benefits ahead of the return of the Lookback Amount. APAC Br., WP-10-B-01, at 7-8.

In contrast, the IOUs, Idaho Power Company (Idaho Power), and the Idaho Public Utilities Commission (IPUC) argue that Staff's recommendation properly reflects the balanced approach decided in the WP-07 Supplemental ROD. IOU Br., WP-10-B-JP1-01, at 91-92; IPUC Br., WP-10-B-ID-01, at 1-3; Idaho Power Br., WP-10-B-IP-01, at 4-8.

BPA Staff's Position

BPA Staff contend that its proposal meets the standards, decisions, and policy objectives established in the WP-07 Supplemental ROD. Evans *et al.*, WP-10-E-BPA-19, at 8-12; Evans *et al.*, WP-10-E-BPA-40, at 6-32. Staff's approach invokes the flexibility afforded the Administrator in the WP-07 Supplemental ROD and properly balances the importance of returning the Lookback Amount within a reasonable timeframe with providing a reasonable level of REP benefits. *Id*. This approach for recovering and returning the Lookback Amount in FY 2010-2011 properly balances the seven policy objectives discussed in the WP-07 Supplemental ROD. Evans *et al.*, WP-10-E-BPA-19, at 8-12. BPA's plan for recovery and return of the Lookback Amount never contemplated a firm commitment to repaying the entire amount within seven years. Evans *et al.*, WP-10-E-BPA-40, at 22-24. Rather, the plan includes flexibility to respond to a host of factors that could affect REP benefit levels over time. *Id*.

Evaluation of Positions

A. Background

In Chapter 9 of the WP-07 Supplemental ROD, the Administrator established that the Lookback Amount would be recovered over time from the IOUs through reductions in their future REP benefits. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 266. These amounts would then be returned to the preference customers that paid BPA's priority firm rates in FY 2002-2006 (PF-02) as credits on their monthly power bills. *Id*. at 279-282. The decisions concerning the amounts to be recovered and returned would occur in each subsequent rate period until the Lookback Amount was totally repaid. *See* WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 263-276.

Because of the many variables that determine REP benefits, the Administrator was clear that there was no "hard and fast" rule that all of the IOUs' Lookback Amounts would be returned to the preference customers by a particular point in time. *Id*. at 273. Rather, BPA's decision regarding the amount to be recovered from each IOU and returned to the PF-02 customers would be made in each rate case. *Id*. at 266. When making this determination, BPA would be guided by the seven policy objectives presented in Bliven *et al.*, WP-07-E-BPA-52, at 21-22, that were also adopted in the WP-07 Supplemental ROD. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 273-275. In this way, the Administrator retained flexibility to address the unique circumstances of each rate case and to balance the seven objectives, which "are overlapping, complex, and at times, in tension with one another." Evans *et al.*, WP-10-E-BPA-40, at 23. This flexibility was essential because, as stated in the WP-07 Supplemental ROD, "the goal of returning the Lookback within seven years may change as a result of the particular circumstances and evidence presented in a future rate case." WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 273. In this regard, the Administrator recognized that

> … there may be legitimate reasons to consider a different approach for recovering the Lookback Amounts that could either accelerate or decelerate the pace of repayment. Thus, it is correct that BPA will have some discretion in future rate proceedings to adjust the Lookback recovery terms to account for the circumstances of each case.

Id. at 269.

In the instant case, Staff proposes to reduce the IOUs' REP benefits due in FY 2010-2011 such that the IOUs' Lookback Amounts would be amortized by FY 2015, which is the seventh year of the amortization plan that started in FY 2009, provided that no individual IOU's REP benefit payment fell below 50 percent. Evans *et al.*, WP-10-E-BPA-19, at 9. Staff reaches this conclusion after reviewing the overall direction provided in the WP-07 Supplemental ROD; Bliven *et al.*, WP-07-E-BPA-52, at 21-22; and Evans *et al.*, WP-10-E-BPA-19, at 8-11. Staff construes the direction in these documents to mean that the "overarching principle adopted in the WP-07 Supplemental ROD is that the Lookback Amount should be returned to the preference customers within a reasonable amount of time, while also allowing for a reasonable level of REP benefits." Evans *et al.*, WP-10-E-BPA-19, at 10.

Staff is properly interpreting the WP-07 Supplemental ROD. BPA's approach to recovering and returning the Lookback Amounts is not a rigid formula. Had BPA intended it to be viewed as such, the WP-07 Supplemental ROD would have given no discretion to the Administrator and would have set forth an inflexible method for recovering the Lookback Amounts. A review of the WP-07 Supplemental ROD reveals that this is not the case. The construct outlined in the WP-07 Supplemental ROD is designed to specifically address the unique policy and equity concerns that confront BPA as it prepares to recover funds from the IOUs and make payments to the preference customers. When making these decisions, the WP-07 Supplemental ROD is clear that BPA must balance two key interests: reducing the IOUs REP benefits to ensure that the preference customers receive Lookback Amount payments from BPA within a reasonable time, *and* ensuring that the IOUs' residential and small farm customers still receive a reasonable amount of statutorily allowed REP benefits. *See* WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 269, 276, 278. In determining how to balance these interests in each rate case, the factors identified in Bliven *et al.*, WP-07-E-BPA-52, at 21-22, are an appropriate way of measuring the reasonableness of Staff's proposal.

B. Final Analysis

In response to this ROD, Staff developed its final analyses of ASCs, the PF Exchange rates, and the level of REP benefits. .Based on Staff's final analysis, the amortization periods of both PacifiCorp and Avista have changed from the Initial Proposal. First, PacifiCorp's benefits are estimated to be nearly twice what they were in the Initial Proposal. As a result, PacifiCorp's anticipated amortization period advanced to FY 2018 from FY 2023. Second, Avista's amortization period is projected to be extended by three years, from FY 2021 to FY 2024, because of a slight decline in REP benefits relative to the Initial Proposal. These final estimates result in approximately $565 million (including accumulated interest) being repaid to the preference customers by FY 2015, which equates to approximately 80 percent of the Lookback Amounts owed by the five IOUs participating in the REP. Lookback Recovery and Return Study, WP-10-FS-BPA-07, at Table 2. If Idaho Power's Lookback Amount is included, the percent returned is 62 percent. *Id.*

C. Response to Parties' Comments

The IOUs support Staff's positions regarding the reasonableness of providing not less than 50 percent of the respective REP benefits due for the FY 2010-11 rate period to residential and small farm customers of IOUs. IOU Br., WP-10-B-JP1-01, at 92. They also indicate that they consider BPA's approach to be well in line with the seven policy objectives identified in the WP-07 Supplemental ROD. *Id*. The Idaho PUC also supports Staff's position. IPUC Br., WP-10-B-ID-01, at 2-3. The Idaho PUC notes that the recovery of the Lookback Amount in seven years is a laudable goal; however, it is not the only policy objective considered by BPA in the WP-07 Supplemental ROD. *Id*. More specifically, the Idaho PUC contends that Staff correctly recognized that recovery of the Lookback Amounts should also allow a reasonable level of REP benefits to residential and small farm consumers of the IOUs and that there should be stability and predictability of REP benefits to IOUs. *Id*.

APAC, PPC *et al.*, and WPAG generally oppose Staff's proposal for the recovery and return of the Lookback Amounts. In general, these parties take certain statements from the WP-07 Supplemental ROD and represent them as binding BPA to a seven-year payback period with little to no room for adjustment. For example, APAC claims that Staff's proposal is directly contrary to the assurances given in the WP-07 Supplemental ROD that the Administrator's authority would be used when necessary to counter decreases in REP benefits and to accomplish a seven-year payback period. APAC Br., WP-10-B-APAC-01, at 5; APAC Br. Ex., WP-10-AP-R-01, at 7. APAC claims that BPA must provide an adequate explanation for its failure to comply with these decisions from the WP-07 Supplemental ROD and for its decision to "change course." APAC Br., WP-10-B-APAC-01, at 5. To support its position, APAC points to statements BPA made in the WP-07 Supplemental ROD where the Administrator noted he had discretion to relax the 50 percent threshold in order to strive for a seven-year payback. *Id.* at 6; APAC Br. Ex., WP-10-AP-R-01, at 7. APAC further claims that the ROD makes clear that the Administrator has the discretion to change the repayment method and relax the 50 percent limitation in order to strive for a seven-year payback. *Id.*

PPC *et al.* echo APAC's concerns by stating that the Administrator explicitly provided in the WP-07 Supplemental ROD that he may alter the "floor" on IOU benefits if it appeared that the amortization period deviated significantly from seven years. PPC *et al.* Br., WP-10-B-JP11-01, at 25. In addition, PPC believes that recovery within seven years better aligns with the policy goals BPA laid out in the WP-07 Supplemental case. PPC *et al.* Br., WP-10-B-JP11-01, at 24-25.

WPAG similarly accuses Staff of abandoning BPA's alleged objective of repaying preference customers the full Lookback Amounts within exactly seven years. WPAG Br., WP-10-B-WG-01, at 16; WPAG Br. Ex., WP-10-R-WG-01, at 18-19. WPAG claims that the Administrator stated clearly in the WP-07 Supplemental ROD that the level of REP benefits paid to the IOUs might fall below 50 percent if that was necessary to ensure that the monies unlawfully taken from the preference customers, and paid to the IOUs, could not be retrieved within the seven-year repayment period. WPAG Br., WP-10-B-WG-01, at 16.

The characterizations of BPA's decisions in the WP-07 Supplemental ROD by APAC, PPC *et al.*, and WPAG are incorrect. BPA's decision to adopt a goal for the return of the Lookback Amount was not meant to convey to the preference customers an iron-clad commitment to return the entire Lookback Amount within a set time period. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 269. As noted throughout section 9.3 of the WP-07 Supplemental ROD, no commitment was made to recover the Lookback Amount in exactly seven years. *Id.* Indeed, BPA specifically rejected such a commitment in the WP-07 Supplemental ROD because it would have been self-defeating. *Id.* at 268-269. As noted in the WP-07 Supplemental ROD:

> Cowlitz and WPAG argue that BPA should make a binding commitment to return the Lookback Amount in at most seven years. APAC similarly argues that the seven-year repayment period is only acceptable if it can assure payment within that time. This proposal must be rejected because it is self-defeating. BPA believes that the most appropriate approach is one that ties the return of funds to COU with the recovery of funds from the IOUs. While BPA has a reasonable degree of confidence that most, if not all, of the Lookback should be repaid within seven years, BPA cannot ensure that the future level of REP benefits will support a seven-year payback. If BPA commits to return the Lookback Amounts in seven years, but has not recovered the funds from the IOUs, BPA would be left in the position of paying Lookback Amounts to the COUs from financial reserves. As noted in Section 9.5, BPA would have to replenish these reserves through future rate increases to the COUs, which has the perverse effect of the COUs paying for their own refund. For this reason, then, BPA will not commit to an absolute seven-year repayment period.

Id. (internal citations omitted).

More to the point, the WP-07 Supplemental ROD is clear in the extensive discussion of section 9.3.2 that the Administrator reserved flexibility to address the situations of each subsequent rate case when balancing the seven-year repayment goal with the level of anticipated REP benefits. Examples of such statements are numerous. For example, in adopting the seven-year goal in the WP-07 Supplemental ROD, BPA noted as follows:

> BPA will also change the goal of returning the Lookback Amounts from 20 years or less to seven years. The seven-year goal reflects BPA's objective of returning the Lookback Amounts to the COUs in the same amount of time during which the overcharges were incurred and responds to arguments made by several parties. BPA, however, believes that a minimal amount of lawfully due REP benefits should be provided to residential customers of the IOUs.

Id. at 266-267 (citations omitted).

Elsewhere in the WP-07 Supplemental ROD, BPA emphasized that the seven-year payback period was a goal, and not a firm commitment:

> The seven-year repayment timeframe is a goal. In each subsequent rate proceeding, the Administrator will assess progress toward that goal, and potentially could relax the 50 percent lower limit in order to accelerate repayment of a particular IOU's Lookback Amount.

Id. at 267.

In addition, BPA also acknowledged that the recovery proposal gave the Administrator discretion to consider changes in light of the circumstances of each case. In the WP-07 Supplemental ROD, BPA explained that:

> …there may be legitimate reasons to consider a different approach for recovering the Lookback Amounts that could either accelerate or decelerate the pace of repayment. Thus, it is correct that BPA will have some discretion in future rate proceedings to adjust the Lookback recovery terms to account for the circumstances of each case.

Id. at 269.

BPA also acknowledged to the IOUs that the seven-year objective was not a "hard and fast rule" that required BPA to set off a specific level of benefits against the Lookback Amounts each rate period. *Id*. at 273-274. Rather, the particular circumstances and facts of each case could be considered by the Administrator to determine the reduction in REP benefits:

> Third, the revised approach allows for a reasonable timeframe for recovery of the Lookback Amounts. To be clear, BPA is not setting a hard and fast rule that within seven years all of the Lookback Amounts will be returned. Rather, BPA is revising its goal of returning the Lookback Amounts from up to twenty years to seven. As noted above, the goal of returning the Lookback within seven years may change as a result of the particular circumstances and evidence presented in a future rate case.

Id. at 273.

As illustrated by the many references described above, BPA's approach for returning the Lookback Amount to the preference customers was never formulaic or mechanical. Rather, it involves considering the particular facts and circumstances of each case in light of the goals and objectives laid out in the WP-07 Supplemental rate proceeding. This analysis not only applies when BPA is determining the Lookback Amount to return to the preference customers; it also applies when BPA is considering the "reasonable" level of lawfully determined REP benefits to allow the IOUs to keep. *Id*. at 266-267. Together, the WP-07 Supplemental ROD requires BPA to balance both ends of this continuum, the amount of refunds to pay to the preference customers and the amount of REP benefits to withhold from the IOUs, when making Lookback Amount recovery and return decisions. That is what BPA has done in reaching its decisions in the instant case. As such, APAC, PPC *et al.*, and WPAG are incorrect to accuse BPA of "changing" course in this proceeding.

APAC, PPC *et al.*, and WPAG are also mistaken to allege that Staff abandoned BPA's commitment to returning the Lookback Amounts within seven years. BPA remains committed to the goal of returning the Lookback Amounts to the preference customers within seven years where such return appears reasonable. For example, BPA is continuing to recover one-seventh of Puget Sound Energy's and PGE's Lookback Amount (plus accumulated interest) in each year of this rate period. Evans *et al.*, WP-10-E-BPA-19, at 10. Thus, BPA is still on track to recover all of Puget Sound Energy's and PGE's Lookback Amount by the end of the seven-year goal established in the WP-07 Supplemental ROD. *Id*. Furthermore, PacifiCorp's Lookback Amount is projected to be recovered only three years later than Puget's and PGE's. Lookback Recovery and Return Study, WP-10-FS-BPA-07, at Table 7. Together, these three utilities account for 75 percent of the original FY 2002-2006 Lookback Amount of $767 million. As a result, approximately three-quarters of the initial $767 million Lookback Amount, including interest, is projected to be returned by FY 2018. FY 2002-2008 Lookback Study, WP-07-FS-BPA-08, at 270; Lookback Recovery and Return Study, WP-10-FS-BPA-07, at Table 12. Nevertheless, BPA's commitment to this goal should not be construed as requiring BPA to ignore the particular facts and circumstances of each case when determining the appropriate division between refunds to the preference customers and REP benefits to the IOUs.

PPC *et al.* object to the extension of the amortization period because, they claim, a seven-year payback best matches the return of the overpayments to the time period over which the harm occurred from the REP Settlement Agreements. PPC *et al.* Br., WP-10-B-JP11-01, at 24-25. The PPC *et al.* objections are misplaced. It is true that in the Initial Proposal both PacifiCorp's and Avista's projected amortization periods were extended by three years relative to the results of the WP-07 Supplemental Final Proposal. Evans *et al.*, WP-10-E-BPA-19, at 10. PPC *et al.* are also correct that returning the Lookback Amount within exactly seven years would roughly match the time period over which the overcharges were collected. However, as noted above, BPA did not decide in the WP-07 Supplemental ROD to return the Lookback Amount to the preference customers within exactly seven years. Rather, BPA's decision to return the Lookback Amount within seven years was a goal subject to the facts and circumstances of each rate case. The previous paragraphs explain why BPA did not make this decision an absolute, invariable commitment to returning the Lookback Amount in exactly seven years. The IOUs and Idaho

PUC support this interpretation of the WP-07 Supplemental ROD. IOU Br., WP-10-B-JP1-01, at 91-92; IPUC Br., WP-10-B-ID-01, at 2-3.

APAC also states that Staff's proposal has improperly put payment of REP benefits ahead of the obligation to correct the harm to preference customers found by the Ninth Circuit. APAC Br., WP-10-B-AP-01, at 8. As such, APAC contends BPA must respond and exercise its ability to reduce REP benefits to ensure that the debts owed to preference customers are repaid in a timely manner. *Id*. WPAG raises a similar concern in its Brief on Exceptions. WPAG Br. Ex., WP-10-R-WG-01, at 17-18. WPAG claims that BPA has put the interests of the IOUs' residential and small farm customers above those of the preference customers who were overcharged in the first place. WPAG Br. Ex., WP-10-R-WG-01, at 17-18. APAC's and WPAG's arguments are not persuasive. In the WP-07 Supplemental ROD, BPA explained why eliminating all of the IOUs' REP benefits would not be appropriate. Specifically, BPA stated:

> However, BPA must balance its responsibility to return these funds against its statutory duty to implement the Residential Exchange Program. There can be little dispute that the REP is a key feature of the Northwest Power Act. It is the only means by which residential consumers of the IOUs receive a benefit from the federally owned and operated hydroelectric dams. Congress bestowed upon the Administrator the duty to implement the REP in accordance with the provisions of the Northwest Power Act, including specifically sections 5(c) and 7(b)(2). 16 U.S.C. §§ 839c(c), 839e(b)(2). As noted by the Court in *PGE*, for the past seven years BPA has failed to implement these provisions, thereby thwarting Congress's intent with the REP. *PGE*, 501 F.3d 1009, 1036-37 (9th Cir. 2007). To remedy this harm, BPA does not believe it reasonable or necessary to go to the other extreme and effectively eliminate the REP for the next seven years or more.

WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 277-278.

This rationale continues to apply here. Again, BPA's Lookback recovery and return construct was designed to address the dual considerations of recovering the Lookback Amount from the IOUs in a reasonable timeframe, while also providing for a reasonable level of REP benefits. *Id*. at 269, 276, 278. Construing this approach to mean that BPA is bound by a rigid formula is not consistent with either the words or the intent of the WP-07 Supplemental ROD.

WPAG argues that Staff is proposing to reverse BPA's previous decision regarding the seven-year period for retrieving the Lookback Amounts by essentially doubling the time period that Avista and PacifiCorp will have to repay their Lookback Amounts. WPAG Br., WP-10-B-WG-01, at 16; WPAG Br. Ex., WP-10-R-WG-01, at 18. As it did in testimony, WPAG simply misstates BPA's decisions in the WP-07 Supplemental ROD. As indicated earlier, BPA did not establish a rigid commitment to repaying the Lookback Amount within seven years. *See* WP-07 Supplemental ROD (Conformed), section 9.3.2. Rather, BPA established a seven-year "goal" of returning the Lookback Amount while also providing a reasonable level of REP benefits. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 276.
WPAG further states that Staff's proposal in the first rate case conducted after the seven-year repayment period was established acts to materially increase the time it will take to retrieve the monies wrongfully taken from BPA's preference customers. WPAG Br., WP-10-B-WG-01,

at 16. BPA disagrees. As noted previously, Staff's final estimates of REP benefits and repayment periods in this case indicate that about 80 percent of the original end-of-FY 2008 Lookback Amount balance, without including Idaho Power, is projected to be repaid to the preference customers by 2015, or within the seven-year goal, as compared to approximately 70 percent in the Initial Proposal. Evans *et al*., WP-10-E-BPA-40, at 17. Of the four utilities participating in the REP, only Avista's repayment time is significantly beyond seven years, with repayment projected to occur in FY 2023, which is eight years longer than FY 2015, not decades as claimed by WPAG. WPAG Br. Ex., WP-10-R-WG-01, at 18. However, the impact of this projection is small given that Avista's Lookback balance at the beginning of this rate period is only $69.9 million of the $673 million total. This result represents a substantial improvement rather than a "material decrease" as indicated by WPAG.

WPAG further characterizes the results of the Initial Proposal as a "doubling of the Lookback Amount repayment period for Avista and PacifiCorp" or claims that BPA has "abandon[ed] compliance with its own 7 year repayment schedule." WPAG Br., WP-10-B-WG-01, at 17; WPAG Br. Ex., WP-10-R-WG-01, at 18. These arguments are incorrect. Evans *et al.*, WP-10-E-BPA-40, at 27-28. There is no doubling of the length of time it would take to repay preference customers under Staff's proposal compared to the decisions in the WP-07 Supplemental ROD, which did not lead to a seven-year amortization for Avista or PacifiCorp. *Id*. The doubling that WPAG asserts appears to be based on the difference between a seven-year repayment by Avista and PacifiCorp that BPA did not establish in the previous rate case and the 13- and 15-year repayment under Staff's Initial Proposal. *Id*. As already noted, Staff's analysis indicates now that PacifiCorp's Lookback Amount could be amortized by as early as FY 2018; that is five years *earlier* than the expectation of FY 2023 under the Initial Proposal.

WPAG further claims that BPA's assessment of the amount by which preference customers were overcharged is half of what it should be. WPAG Br. Ex., WP-10-R-WG-01, at 18. BPA's decisions that led to the calculation of the total overcharges to the preference customers due to the 2000 REP Settlement Agreements is fully documented in the WP-07 Supplemental ROD and the FY 2002-2008 Lookback Study. FY 2002-2008 Lookback Study, WP-07-FS-BPA-08. BPA will not repeat these decisions and calculations here. BPA continues to stand behind those calculations as legally and analytically correct. WPAG seems to be asserting a difference of opinion regarding the treatment of the Load Reduction Agreements with PacifiCorp and Puget. BPA has previously responded to WPAG's arguments in the WP-07 Supplemental ROD. *See* WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 180-190.

In summary, the decisions in the WP-07 Supplemental ROD require the Administrator to balance two goals when deciding the level of Lookback to recover from the IOUs in each rate period: 1) the goal of returning the Lookback Amount to the preference customers within a reasonable timeframe, and 2) the goal of providing a reasonable level of REP benefits to the residential and small farm customers of the IOUs. Flexibility to respond to the unique circumstances of each rate case is inherent in this proposal. The flexibility to either decelerate or accelerate repayment is essential because of the many variables and considerations that inevitably arise in a rate proceeding or in the review of a utility's ASC. As shown in the results of this rate case, a utility's REP benefits may double between the beginning and the end of the proceeding (*i.e.*, PacifiCorp) or fall even lower (*i.e.*, Avista). The Administrator must have discretion to respond to these changing circumstances. In arriving at the appropriate balance between providing refunds to the preference customers and paying REP benefits to the IOUs, BPA's decision will be guided by the seven policy objectives listed in Bliven *et al.*, WP-07-E-BPA-52, at 21-22, and the particular facts and circumstances of each case. In the instant case, BPA has reviewed these objectives and is adopting an approach to recovering and returning the Lookback Amounts for FY 2010-2011 that strikes the proper balance between these competing interests.

Decision

BPA's approach for recovery and return of the Lookback Amount in FY 2010-2011 is consistent with the decisions made in the WP-07 Supplemental ROD. This approach properly uses the flexibility afforded to the Administrator and balances the goals of returning the Lookback Amount to the PF-02 customers in a reasonable time, while also providing the residential and small farm customers of the IOUs a reasonable level of REP benefits.

15.3 Renewal of the 50 Percent Threshold in FY 2010-2011

Issue 1

Whether the 50 percent threshold for REP benefits paid should be renewed for FY 2010-2011 as a component of the approach to recovering and returning the Lookback Amount.

Parties' Positions

APAC, PPC *et al.*, and WPAG object to the renewal of the 50 percent threshold in this rate period. APAC Br., WP-10-B-AP-01, at 5-8; PPC *et al.* Br., WP-10-B-JP11-01, at 24-26; WPAG Br., WP-10-B-WG-01, at 15-18. They claim that it results in an unacceptable delay in the return of the total Lookback Amount to the PF-02 customers. APAC Br., WP-10-B-AP-01, at 5-8; PPC *et al.* Br., WP-10-B-JP11-01, at 24-26; WPAG Br., WP-10-B-WG-01, at 15-18. WPAG further claims that the application of the 50 percent threshold to maintain a "reasonable" level of REP benefits indicates that BPA is clearly placing the continued payment of REP benefits to the IOUs above its obligation to repay the preference customers for the overcharges due to the REP Settlement Agreements. WPAG Br. Ex., WP-10-R-WG-01, at 17-18.

The IOUs and the Idaho PUC support the continued application of the 50 percent threshold in FY 2010-2011 as an appropriate balance between repayment of the Lookback Amount and the provision of a reasonable level of REP benefits to the residential and small farm consumers of the IOUs, specifically Avista and PacifiCorp. IOU Br., WP-10-B-JP1-01, at 91-92; IPUC Br., WP-10-B-ID-01, at 1-3.

BPA Staff's Position

BPA Staff recommends that the 50 percent threshold be renewed for FY 2010-2011 as an appropriate balance between returning the Lookback Amount to the PF-02 customers within a reasonable timeframe while providing a reasonable level of REP benefits. Evans *et al.*, WP-10-E-BPA-19, at 8-12; Evans *et al.*, WP-10-E-BPA-40, at 9-32. In this rate period, the 50 percent threshold should apply to the REP benefits and Lookback recovery for Avista and PacifiCorp. Evans *et al.*, WP-10-E-BPA-19, at 10.

Evaluation of Positions

In the WP-07 Supplemental ROD, BPA decided to apply no more than 50 percent of an IOU's REP benefits against its Lookback Amount for FY 2009. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 266. BPA noted that the 50 percent limitation "will be subject to reconsideration in future rate proceedings[.]" *Id.* This limitation was adopted as a component of BPA's decision to change its goal for returning the Lookback Amounts from 20 years to seven. *Id.* at 266-267.

In this rate case, Staff proposes to reduce the IOUs' REP benefits due in FY 2010-2011 such that the IOUs' Lookback Amounts would be amortized by FY 2015, which is the seventh year of the amortization plan started in FY 2009, provided that no individual IOU's REP benefit level falls below 50 percent. Evans *et al.*, WP-10-E-BPA-19, at 9. Staff proposes this approach after considering the seven policy objectives established in Bliven *et al.*, WP-07-E-BPA-52, at 21-22, that were also used to guide the decisions in section 9.3.2 of the WP-07 Supplemental ROD. Evans *et al.*, WP-10-E-BPA-19, at 8-12; Evans *et al.*, WP-10-E-BPA-40, at 11, 14, 19. Specifically, these objectives are as follows:

- First, the approach must be consistent with law and consistent with the Court's rulings;
- Second, the approach must be reasonable given the circumstances;
- Third, the approach should, to the extent possible, recover the Lookback Amounts from the IOUs and return them to the COUs over a reasonable period of time;
- Fourth, timely recovery of Lookback Amounts should also allow a reasonable level of REP benefits to residential and small farm consumers of the IOUs if, in fact, such benefits are owed;
- Fifth, the approach should reflect the fact that key factors impacting future REP benefits, including IOU and BPA costs, load growth, regulatory and environmental policies, and other factors cannot be forecast with precision;
- Sixth, stability and predictability of REP benefits to IOUs and of REP costs borne by COUs is a laudable and appropriate policy objective, but this objective should be pursued in light of the uncertainties and practical limitations noted previously;
- Seventh, the approach should, to the extent possible, reflect the perspectives and input of BPA's customers and other regional stakeholders.

Evans *et al.*, WP-10-E-BPA-19, at 8; *see also* Bliven *et al.*, WP-07-E-BPA-52, at 21-22; WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 266.

Staff determined that the 50 percent threshold should be continued for the FY 2010-2011 rate period because it meets the seven objectives established in the WP-07 Supplemental ROD. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 266. First, under the Initial Proposal, if BPA had proposed to amortize all of the IOUs' Lookback Amounts by FY 2015, Avista would receive approximately 11 percent of its REP benefits during the WP-10 rate period, while PacifiCorp would receive no REP benefits at all. Evans *et al.*, WP-10-E-BPA-19, at 9-10. Staff's amortization projections have changed in its final rate analysis prepared for the ROD. Final projections indicate that Avista is unable to fully amortize its Lookback Amount by FY 2015, even if all of Avista's REP benefits are used to pay back its Lookback Amount. In PacifiCorp's case, BPA would have to apply 65 percent of its REP benefits to recover its Lookback Amount by FY 2015, leaving only 35 percent for its residential and small farm customers. These results are still not consistent with the second and fourth objectives stated above, which maintains that the Lookback approach should be reasonable and provide a reasonable level of REP benefits (when legally due) to the residential and small farm customers of the IOUs. *Id.*

Second, adopting a 50 percent threshold for this rate period does not materially affect the third goal of returning the Lookback Amount to the COUs within a reasonable time. *Id.* at 10. Using the simplified assumption that REP benefits will remain at FY 2011 levels (in nominal terms), the 50 percent threshold has no impact on the payoff of the Lookback Amounts of Portland General Electric (PGE) and Puget Sound Energy. *Id.* Both of these utilities are forecast to completely amortize their respective Lookback Amounts by FY 2015. *Id.* The 50 percent limitation also has no impact on NorthWestern Energy, because it has already extinguished its Lookback Amount. *Id.* Idaho Power is similarly not affected by the 50 percent limitation, because it is not forecast to receive REP benefits during the rate period. *Id.* Thus, the only utilities impacted by the 50 percent approach are Avista and PacifiCorp. *Id.*

In the Initial Proposal, for Avista and PacifiCorp, imposition of the 50 percent threshold resuled in a projected payoff of their Lookback Amounts in FY 2021 and FY 2023, respectively, under the assumption that their REP benefits remain at the FY 2011 level. *Id; see also* Lookback Return and Recovery Study, WP-10-FS-BPA-07, Table 5. Under BPA's current projections, these amortization dates are now expected to be FY 2023 for Avista and FY 2018 for PacifiCorp. While these projected pay-off dates are beyond the FY 2015 goal articulated in the WP-07 Supplemental ROD, BPA views these delays as reasonable in light of the seven objectives. Evans *et al.*, WP-10-E-BPA-19, at 10.

Furthermore, even with the 50 percent limitation in place, a significant portion of the total Lookback Amount is projected to be returned to preference customers by FY 2015. Evans *et al.*, WP-10-E-BPA-19, at 10; Evans *et al.*, WP-10-E-BPA-40, at 17. In the Initial Proposal, Staff projected that nearly 70 percent of the Lookback Amounts of all of the IOUs but Idaho Power would be returned to the preference customers by FY 2015. Evans *et al.*, WP-10-E-BPA-19, at 10. Using the final study estimates, Staff projects this figure to be *80 percent*. Lookback Recovery and Return Study, WP-10-FS-BPA-07, at Table 2. Furthermore, by the end of FY 2011, BPA is projected to have returned $587 million (including accumulated interest) to the preference customers for FY 2002-2008. *Id.*

Moreover, the preference customers are not harmed by having to wait longer for the remaining portions of the Lookback Amount because all Lookback Amount balances accrue interest. *Id.* For these reasons, BPA believes the third objective of returning the Lookback Amounts within a reasonable time is met under BPA's proposal. *Id.*

BPA also considered the fifth and sixth policy factors outlined above. *Id.* at 11. The fifth policy factor states that BPA's approach should reflect the fact that key factors affecting future REP benefits, including IOU and BPA costs, load growth, regulatory and environmental policies, and other factors, cannot be forecast with any precision. *Id.* Staff noted that its forecast of when the Lookback Amounts will be completely paid still retains a significant degree of uncertainty, as it did in the last rate proceeding. *Id.* For example, the projected payoff date is based on the simplified assumption that annual REP benefits after 2011 are the same as REP benefits projected for FY 2011. *Id.* This assumption, however, does not take into account the plethora of changes that may result in higher (or lower) REP benefits over time. As a case in point, Staff's most current estimates forecast PacifiCorp paying off its Lookback Amount by FY 2018, five years sooner than Staff originally projected in the Initial Proposal. Such variations indicate how difficult it is to predicate exactly when the preference customers will receive all of their refunds from BPA. Evans *et al.*, WP-10-E-BPA-19, at 11.

The sixth policy factor provides that BPA should aim for stability and predictability of REP benefits to IOUs and of REP costs borne by COUs. *Id.* Maintaining the 50 percent threshold in FY 2010-2011 generally meets this objective, because it results in about $17 million lower IOU REP benefits paid ($190 million for FY 2009 compared to an average of $173 million for FY 2010-2011) and about $5 million higher Lookback Amount recovered and returned to COUs each year of the rate period as compared to FY 2009, after accounting for the Avista deemer settlement. ($77 million FY 2009 compared to an average of $81.5 million for FY 2010-2011). Lookback Recovery and Return Study, WP-10-FS-BPA-07, at Table 5. Conversely, if the 50 percent threshold is abandoned in this case, the total amount of REP benefits paid to Avista would be reduced to zero (and still would not have repaid its Lookback Amount by FY 2015), while PacifiCorp's REP benefits would be only 35 percent of the REP benefits due. BPA does not believe that substantially reducing REP benefits to the region's residential and small farm consumers within only a year's time is consistent with the policy guidance outlined above, and that the better approach is to maintain a stable return of the Lookback Amounts that also results in a reasonable level of REP benefits. Evans *et al.*, WP-10-E-BPA-19, at 11. BPA also remained open to hearing proposals from other parties, thus meeting the seventh objective. *Id.*

The IOUs support Staff's position. IOU Br., WP-10-B-JP1-01, at 91-92. The IOUs maintain that continuation of the 50 percent threshold in this rate case is reasonable and meets the policy objectives established in the WP-07 Supplemental ROD. *Id.* In addition, the Idaho PUC states that "Staff appropriately balanced the time period for repaying the Lookback Amounts to the COUs, with providing a reasonable level of REP benefits to the eligible IOUs." IPUC Br., WP-10-B-ID-01, at 2. These parties agree that BPA's evaluation of the continuation of the 50 percent threshold in FY 2010-2011 represents a reasonable balance between the competing goals of returning the Lookback Amount within a reasonable timeframe with providing the IOUs with a reasonable level of benefits. *Id.*

APAC, WPAG, and PPC *et al.*, however, generally oppose BPA's proposal to implement the 50 percent threshold for REP benefits.

APAC argues in its brief that delaying repayment in order to protect the "goal" of the IOUs retaining 50 percent of their Residential Exchange benefits is unfair and unreasonable, and contrary to the decisions made in the WP-07 Supplemental ROD. APAC Br., WP-10-B-AP-01, at 5-6. APAC further argues that the additional delay in repayment by Avista and PacifiCorp substantiate Cowlitz's concern and provide exactly the justification suggested by the ROD for the relaxation of the 50 percent minimum. *Id*. at 6.

APAC's concerns are misplaced. Contrary to APAC's arguments, adopting the 50 percent threshold in this rate period is reasonable for several reasons. First, while it is true that the result of adopting the 50 percent threshold in this case is a projected delay in the repayment of Avista's and PacifiCorp's Lookback Amounts, the results of not adopting the 50 percent threshold are certainly more unreasonable. As noted above, if BPA were to abandon the 50 percent threshold in this case and try to fully amortize the Lookback Amounts of Avista and PacifiCorp, Avista would receive no REP benefits (and still not meet the FY 2015 goal) and PacifiCorp would receive only approximately 35 percent of its benefits. BPA still considers this outcome to be inconsistent with the second and fourth objectives established by Bliven *et al.*, WP-07-E-BPA-52, at 21-22.

Second, as noted before, the WP-07 Supplemental ROD stated that "the amounts to be applied to the IOUs' Lookback Amounts would be addressed in each rate case and could account for current circumstances." WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 269; Evans *et al.*, WP-10-E-BPA-40, at 11. The "current circumstances" arising in this rate period are that the REP benefits of Avista and PacifiCorp are not particularly high relative to their outstanding Lookback balances. Hence, provision of 50 percent of their REP benefits due is a reasonable level of benefits. Evans *et al.*, WP-10-E-BPA-40, at 11. Again, the overarching principle adopted in the WP-07 Supplemental ROD is that the Lookback Amount should be returned to the preference customers within a reasonable amount of time while also allowing for a reasonable level of REP benefits. Evans *et al.*, WP-10-E-BPA-40, at 10.

Furthermore, under a set of simplifying assumptions in the Initial Proposal, even with the extension noted in the Initial Proposal, nearly 70 percent of the Lookback Amount, excluding Idaho Power, is projected to be repaid within seven years. *Id*. at 10. Therefore, the continued adoption of the 50 percent threshold meets the third objective of returning the Lookback Amount over a reasonable amount of time. *Id*. at 10-11. As noted above, under Staff's updated estimates, this number rises to close to *80 percent*. Furthermore, the adoption of the 50 percent threshold in this rate period recognizes the fact that key factors affecting future REP benefits cannot be forecast with precision and maintains a stable amount of REP benefits paid to the IOUs, thus meeting the fifth and sixth objectives. *Id*. at 11-12.

Continuing to provide 50 percent of the REP benefits due to the IOUs is further supported by the decision in the WP-07 Supplemental ROD that states "BPA's approach to providing some level of legally justifiable REP benefits … is not improper… and presents a reasonable balance between the interests of the COUs and the residential consumers of the IOUs…." WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 278. That is what BPA is doing in the instant case.

WPAG takes issue with Staff's representation of the results of applying the 50 percent threshold in this rate period, stating that the 50 percent threshold "will greatly extend the Lookback Amount repayment period for Avista and PacifiCorp." WPAG Br., WP-10-B-WG-01, at 17. WPAG continues to assert that such a prolonged delay proposed by BPA in the repayment of monies unlawfully taken from BPA's preference customers, to sustain payments to those who benefitted from the original unlawful payments, is both unreasonable and inequitable. *Id.*

BPA disagrees. First, it should be noted that, compared to the WP-07 Supplemental ROD, application of the 50 percent threshold in FY 2010-2011, under a simple view of future REP benefits, results in an acceleration of the amortization period for PacifiCorp of two years (from FY 2020 to FY 2018) and an extension for Avista of five years (from FY 2018 to FY 2023). Lookback Recovery and Return Study, WP-10-FS-BPA-07, at Table 7. These changes, when compared to the results of the WP-07 Supplemental Final Proposal, do not constitute an unreasonable change from the original projections. Furthermore, such changes are appropriate in the context of balancing the repayment timeframe with the goal of providing a reasonable level of REP payments, as supported in Section 9.3.2 of the WP-07 Supplemental ROD. WP-07 Supplemental ROD (Conformed), WP-10-A-05, at 263-278; Evans *et al.*, WP-10-E-40, at 14. In addition, the PF-02 customers are compensated for the time value of money associated with these projected extensions. Evans *et al.*, WP-10-E-BPA-19, at 10-11. Lastly, these projections are based on a very simplified view of constant REP benefits, in nominal terms, throughout the future. These simple projections do not account for the many variables that are likely to change over time, such as average system costs of the IOUs, BPA's costs and rates, load growth, and regulatory changes. Evans *et al.*, WP-10-E-BPA-19, at 11. Changes in any of these areas can affect the projected payoff dates of the IOUs' respective Lookback Amounts.

WPAG further takes issue with Staff's presentation of the impacts of the adoption of the 50 percent threshold, which it claims results in the percentage of the total Lookback Amounts repaid by FY 2015 amounting to only 50 percent of the outstanding Lookback Amount balance, not the 70 percent claimed by BPA. WPAG Br., WP-10-B-WG-01, at 17. While this is a different presentation of the numerical results of Staff's simplified projections, BPA believes that it is not appropriate at this time to include Idaho Power's Lookback Amount when citing statistics on the repayment, because Idaho Power is not eligible for REP benefits in this rate period. Furthermore, as discussed previously, all statistics regarding the projections of repayment of the Lookback Amount should be treated with reserve, as they are predicated on the simple assumption that Staff's current projection of REP benefits in FY 2011 will continue, in nominal terms, through the future. Evans *et al.*, WP-10-E-BPA-19, at 11. In fact, these projections do not include likely future changes in ASCs, BPA's costs, load growth, and regulatory or other changes because such changes cannot be forecast at this point with any meaningful level of precision. *Id.*

WPAG contends that Staff has made the wrong policy choice in proposing to extend the Lookback Amount repayment period for Avista and PacifiCorp. WPAG Br., WP-10-B-WG-01, at 17-18. First, by extending the Lookback Amount repayment period for Avista and PacifiCorp, WPAG argues, BPA would be reducing the payments received by preference customers during the rate period by about $58 million, or about a 30 percent reduction in the Lookback Amount repayments they would have received had BPA continued to implement the seven-year repayment period. *Id*. at 13. WPAG argues that this is a substantial increase to the net BPA power costs paid by preference customers, and comes at a time when they are struggling to deal with the worst economic recession in a generation. *Id*. By taking the proposed action, WPAG concludes, BPA will be making a bad economic situation even worse for all of its preference customers. *Id*.

While BPA understands WPAG's calculations, BPA does not accept the premise that the standard of comparison is a strict seven-year payment timeframe. As already explained, BPA did not commit to repay the entire Lookback Amount within exactly seven years. In addition, BPA notes that WPAG's concerns are significantly addressed through the preliminary results of the current rate analysis that show that PacifiCorp's amortization period is likely to be substantially shortened—instead of a projected 15-year amortization period, Staff's most recent estimates place it at 10 years, at the end of FY 2018. While Avista's amortization period is likely to be longer due to lower REP benefits and the effect of the 50 percent threshold, Avista's Lookback Amount is relatively small, and this result has little effect on the pace of repayment of the total Lookback Amount to the preference customers. Moreover, the preference customers receive additional compensation through the accumulation of interest on the unamortized Lookback Amounts.

PPC *et al.* and WPAG argue that, based on the Initial Proposal results, the proposed extension of the amortization period is likely to undermine the preference customers' confidence that the BPA proposal will adequately remedy the harm that was identified by the Ninth Circuit and by BPA in the WP-07 Supplemental proceeding. PPC *et al.* Br., WP-10-B-PP-01, at 25; WPAG Br. Ex., WP-10-R-WG-01, at 18. In addition, PPC *et al.* claim that extending the amortization period would also increase the chances that Staff's proposed remedy will not survive judicial review. *Id*. PPC *et al.*'s concerns are misplaced. First, BPA does not agree that Staff's proposal should be viewed as undermining the adequacy of BPA's remedy to the Ninth Circuit's decisions. Far from it, this case further demonstrates BPA's sincere intent to return funds to the preference customers in a timely fashion.

For one, BPA has already made substantial progress in returning refunds to the preference customers. Although not mentioned in PPC *et al.*'s brief, BPA made over $250 million in cash payments to the preference customers at the close of the WP-07 Supplemental Rate Proceeding to compensate them for the overcharges they incurred in FY 2007-2008. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 289. In addition, as of the beginning of FY 2009, the original FY 2002-2006 Lookback Amount of $767 million was reduced to $673 million as a result of the Avista deemer settlement as well as the application of $87.5 million of the IOUs' FY 2008 REP benefits toward their respective Lookback Amount balances. This $87.5 million of Lookback payments is part of the $154 million being returned to the COUs in FY 2009. In total, during FY 2009-2015, BPA is projected to return to the preference customers about *$565 million,* including interest, in refunds. Lookback Recovery and Return Study, WP-10-FS-BPA-07, at Table 2. BPA acknowledges that under Staff's simplified assumptions approximately $253 million of the Lookback Amount may be outstanding as of FY 2016. *Id*. But even so, BPA believes that returning these substantial payments demonstrate that substantial progress will have been made in the return of the Lookback Amount. Thus, BPA does not concur that its current proposal should cause the preference customers to be concerned with the adequacy of BPA's Lookback remedy.

PPC *et al.*'s second point is equally inapposite. PPC *et al.* argue that Staff's proposal increases the chances that BPA's proposed remedy will not survive judicial review. PPC *et al.* Br., WP-10-B-PP-01, at 25. WPAG raises a similar concern in its Brief on Exceptions. WPAG Br. Ex., WP-10-R-WP-01, at 14. BPA does not agree. For one, BPA does not believe the Ninth Circuit will find fault with BPA's decision to return a projected total of about $900 million in refunds,which includes accumulated interest, to the preference customers by FY 2015. Lookback Recovery and Return Study, WP-10-FS-BPA-07, at Table 2. BPA has made efforts to quickly and efficiently return the overcharges to the preference customers. Returning rate refunds to customers in an expeditious fashion is rarely achieved in the utility industry, particularly when the refund determinations are controversial and subject to appeal. As a case in point, claims in the California Refund Proceeding have languished before the Federal Energy Regulatory Commission for well over eight years. To date, no party in that proceeding has received refunds from the funds held by the Commission (outside of a negotiated settlement). By way of contrast, BPA's preference customers received hundreds of millions of dollars in refunds from BPA within *18 months* of the Ninth Circuit's decision in *Golden NW* and *PGE*. Lookback Recovery and Return Study, WP-10-FS-BPA-07, at Table 2. In addition, for this rate period, BPA's decision returns an additional $163 million in refunds to the preference customers. *Id*. The Ninth Circuit should view these actions by BPA as reasonable and responsive to its decisions.

Furthermore, BPA believes there are persuasive arguments regarding equity that support BPA's decision to allow a reasonable level of REP benefits to flow through to regional ratepayers. BPA's position on this issue was cogently presented in the WP-07 Supplemental ROD. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 277-278. As stated there:

> …as a matter of equity … it is appropriate to provide some level of legally determined REP benefits to the residential consumers of the IOUs. BPA recognizes that the COUs have been overcharged for REP benefits and now must receive refunds. As Staff has stated throughout this proceeding, BPA is committed to returning those funds to the COUs within a reasonable time. Bliven, *et al.*, WP-07-E-BPA-52, at 21. Returning these funds to the COUs is crucial to responding to the Court's remand in *Golden NW* and to the general policy of undoing the harm caused by BPA's legal error. However, BPA must balance its responsibility to return these funds against its statutory duty to implement the Residential Exchange Program. There can be little dispute that the REP is a key feature of the Northwest Power Act. It is the only means by which residential consumers of the IOUs receive a benefit from the federally owned and operated hydroelectric dams. Congress bestowed upon the Administrator the duty to implement the REP in accordance with the provisions of the Northwest Power Act, including specifically sections 5(c) and 7(b)(2). 16 U.S.C. §§ 839c(c), 839e(b)(2). As noted by the Court in *PGE*, for the past seven years BPA has failed to implement these provisions, thereby thwarting Congress's intent with the REP. *PGE*, 501 F.3d 1009, 1036-37 (9th Cir. 2007). To remedy this harm, BPA

> does not believe it reasonable or necessary to go to the other extreme and effectively eliminate the REP for the next seven years or more.

Id. These arguments will lend even further support to BPA's decisions before the Ninth Circuit. The PPC *et al.* assertion that BPA's proposal will "not survive judicial review" is unfounded speculation.

PPC *et al.* argue that all parties would be better served by BPA seeking recovery of the full Lookback Amounts within seven years. PPC *et al.* Br., WP-10-B-PP-01, at 25. PPC *et al.* assert that the publics would be benefitted by a greater likelihood of receiving a remedy, and the IOUs would be benefitted by a decreased likelihood of significant intergenerational mismatches between those customers that received the unlawful benefits and those that have to pay them back. *Id.* PPC *et al.*'s arguments are unpersuasive. PPC *et al.*'s first argument is simply self-serving. Preference customers of course would be benefitted if BPA were to return all of the Lookback Amounts as quickly as possible. If that were BPA's only concern, BPA would have decided in the WP-07 Supplemental ROD to simply reduce all future REP benefits until the Lookback Amount was fully repaid. For the reasons discussed throughout this section, however, BPA chose not to make that decision. Instead, BPA designed the recovery and return of the Lookback Amount to consider various competing interests on a case-by-case basis. While this approach may cause the return of the Lookback Amount to be stretched over a longer period of time, it should not threaten the likelihood that the preference customers will receive an adequate remedy from BPA.

PPC *et al.*'s second point, that a quicker return of the Lookback Amount is beneficial to the ratepayers of the IOUs, is belied by the fact that the IOUs and the Idaho PUC urge BPA to reject PPC *et al.*'s proposal, and they support Staff's position in this case. IOU Br., WP-10-B-JP1-01, at 91-92; IPUC Br., WP-10-B-ID-01, at 1-3. BPA believes the IOUs and the Idaho PUC are in a better position to describe what is best in terms of the interest of regional residential and small farm consumers when discussing reductions in REP benefits. PPC *et al.*'s arguments are not persuasive.

In its Brief on Exceptions, WPAG upbraids BPA for its efforts to maintain a reasonable balance between returning Lookback Amounts to the preference customers and paying REP benefits to the IOUs' residential and small farm customers. WPAG Br. Ex., WP-10-R-WG-01, at 17-19. WPAG claims that it "is difficult to find words" to fully express its frustration in seeing BPA provide REP payments to the IOUs whose customers were the beneficiaries of BPA's illegal actions. *Id.* at 17-18. WPAG alleges that BPA has "disregarded" its obligation to repay its preference customers, whose consumers were overcharged due to BPA's illegal actions. *Id.* WPAG then criticizes BPA's decision to consider the interests of residential and small farm ratepayers in determining the pace of repayment of the Lookback Amount, resolving that BPA's proposal is so unreasonable that it "deserves no reply." *Id.* at 18.

Although WPAG attempts to paint Staff's proposal as a betrayal of BPA's commitment to provide refunds to injured preference customers, the evidence in the record tells a much different story. One need only look to the amount of overcharges that has been returned to preference customers to date to see the speciousness of WPAG's comments. Of the original total refund obligation of $985 million that BPA decided in the WP-07 Supplemental ROD, approximately

$424 million (which includes accumulated interest) will be returned to preference customers by the end of FY 2009. Lookback Recovery and Return Study, WP-10-FS-BPA-07, at Table 2. In addition, BPA is proposing to return in this case an additional *$163 million*. *Id*. Thus, by the end of this rate period, the preference customers will have received a total of *$587 million* in payments from BPA. *Id*. WPAG studiously avoids mentioning any figures in its brief because to do so would immediately show the disingenuousness of its arguments. As the record clearly shows, even with BPA's decision to provide a "reasonable" level of REP benefits to the IOUs' residential and small farm customers, BPA is making excellent progress in its effort to return refund payments to the preference customers.

Continuing on with its unsubstantiated complaints, WPAG next argues that BPA's plan for returning the overcharges to the preference customers significantly delays the necessary complete restitution of such overcharges because it extends the necessary repayment "into the indefinite future." WPAG Br. Ex., WP-10-R-WG-01 at 18. Furthermore, WPAG asserts without explanation that BPA cannot be relied upon to enforce its repayment obligation, given the recent settlement of Avista's deemer balance. *Id*.

WPAG simply misstates the facts. First, BPA has a plan for recovering and returning the overcharges to the preference customers that is thoroughly described and documented in the WP-07 Supplemental ROD. *See* WP-07 Supplemental ROD (Conformed), WP-07-A-05, Chapter 9. Now, in this first rate case since that ROD, BPA is again following the plan. As just noted, under this plan BPA will have returned $424 million (which includes accumulated interest) of the original $985 million in overcharges as of the end of FY 2009, only 2 and a half years since the Ninth Circuit ruled. An additional $163 million will be returned in FY 2010-2011, for a total of $587 million. By most standards, this would constitute admirable progress, not "the indefinite future."

Second, WPAG's reference to the Avista Deemer Settlement as evidence that BPA cannot be relied upon to fulfill its refund obligation is simply inapposite. WPAG Br. Ex., WP-10-R-WG-01, at 18. The facts and circumstances surrounding the accumulation and calculation of Avista's deemer balance are wholly unrelated to the recovery and return of the Lookback Amounts. Avista's deemer dispute involved the implementation of a 20-year old contractual provision that had never been litigated in open court. The disputes over BPA's Lookback Amount construct, in contrast, involve BPA's response to a remand by the Ninth Circuit, which is now pending before the Ninth Circuit in numerous petitions. The legal posture of these two disputes is, therefore, dramatically different. As explained in the Avista Deemer Settlement ROD:

> PPC's concern that the Settlement will somehow diminish BPA's resolve to return the Lookback Amounts to preference customers is unfounded. The Lookback construct stands in a totally different position than Avista's long-standing deemer balance dispute. For one, several cases are currently pending before the Ninth Circuit challenging BPA's decisions over the determination, calculation, and return of the Lookback Amounts to preference customers. BPA anticipates that more cases will be filed once BPA's rates are finally approved by FERC. Thus, unlike the deemer account balance disputes that have remained unresolved for decades, the legal questions surrounding the validity and

> calculation of the Lookback Amounts are on a course to be determined by the Court. There is also a possibility that these cases will reach settlement. In either event, BPA is confident that through these cases the Lookback issues will reach a final resolution that will provide PPC and BPA certainty as to what amounts, if any, that BPA should be returning to preference customers. If PPC finds BPA taking a course of action that PPC considers inconsistent with the holdings of the Court or terms of any settlement after these issues are resolved, it will have ample opportunities to bring that fact to the Court's attention. Thus, PPC's concern that BPA's decision to settle with Avista will somehow endanger preference customers' rights to the Lookback Amount is not persuasive.

Deemer Account Settlement Agreement with Avista Corporation, Administrator's Record of Decision, June 22, 2009, at 64. As such, WPAG's concern that the deemer balance settlement demonstrates that "repayment delayed is repayment foregone" is without merit.

WPAG concludes its diatribe against BPA's proposal by arguing that there are no legally defensible excuses available to BPA for failing to seek repayment from those IOUs that have repaid nothing (Idaho Power), or for further delaying the repayment by those IOUs that are fully capable of doing so (PacifiCorp and Avista). WPAG Br. Ex., WP-10-R-WG-01, at 18. WPAG then threatens to use "legal action" to seek recovery of the funds rightfully due to it if BPA decides to extend the Lookback repayment period for PacifiCorp and Avista. *Id. at 19*.

BPA responds to WPAG's accusations on the non-payment of Idaho Power in section 15.4. As to WPAG's threat of legal action against BPA for extending the time period for repayment of PacifiCorp and Avista, BPA is undeterred. BPA's proposal in this case implements the decisions made in the WP-07 Supplemental ROD, which requires BPA to balance its obligation to repay the Lookback Amounts to preference customers with its commitment to provide a reasonable level of lawfully due REP benefits to the IOUs' residential and small farm customers. Until this proposal is found to be unlawful or otherwise unreasonable, BPA will not deviate from it simply because of threats of litigation.

Furthermore, WPAG's threat of litigation is immaterial because the decisions BPA made in the WP-07 Supplemental ROD are already pending before the Ninth Circuit. BPA presumes that one of the issues the Ninth Circuit will address will be the agency's recovery and return proposal for the overcharges to the COUs. Thus, the merits of BPA's proposal are already on course to being decided by the Ninth Circuit. Although WPAG claims that it has "no alternative" but to seek funds through "legal action," one logical alternative would be to wait until the issues in the WP-07 Supplemental ROD are resolved by the Ninth Circuit or through a global settlement. This alternative makes perfect sense because, in the meantime, WPAG's preference customer members will enjoy the benefit of receiving their share of the $163 million that BPA will be returning over the next two years.

Finally, to the extent WPAG means to convey in its Brief on Exceptions that it intends to file additional claims against BPA if WPAG's demands are not met in this case, then BPA is truly perplexed. In these trying economic times, BPA does not see the sense in WPAG filing time-intensive and costly litigation, particularly where the issues in the case will be duplicative of issues already pending before the Ninth Circuit. The fact that WPAG would suggest such a wasteful endeavor threatens the credibility of WPAG's entreaties to the Administrator regarding the seriousness of the current economic situation facing its members. *See* WPAG Br. Ex., WP-10-R-WP-01, at 14; Mundorf, Oral Tr. 226-227.

Decision

BPA will renew the 50 percent threshold for REP benefits in this rate period. Retaining the 50 percent threshold appropriately balances the competing objectives of returning the Lookback Amount to the PF-02 customers within a reasonable timeframe with providing a reasonable level of REP benefits to the IOUs' residential and small farm customers.

15.4 Lookback Recovery and Return Issues Related to Idaho Power Company

Issue 1

Whether BPA's approach for recovering and returning the Lookback Amounts adequately addresses the situation presented by Idaho Power Company.

Parties' Positions

APAC argues that BPA should revise its repayment methodology in the current rate case to provide an effective method for commencing recovery of Idaho Power Company's (Idaho Power) Lookback Amount. APAC Br., WP-10-B-AP-01, at 9; APAC Br. Ex., WP-10-R-AP-01, at 7-8.

Similarly, WPAG argues that Staff's proposed method for recovering and returning Lookback Amounts will result in the repayment of no portion of Idaho Power's Lookback Amount. WPAG Br., WP-10-B-WG-01, at 8-9. WPAG recommends that BPA take "additional steps" to recover these funds from Idaho Power and assume that two-sevenths of Idaho Power's Lookback Amount would be recovered in FY 2010-2011. *Id*. at 9. In its Brief on Exceptions, WPAG again chastises BPA for its "inaction in the face of this outstanding liability" and offers additional suggestions for recovery of Idaho Power's Lookback Amount. WPAG Br. Ex., WP-10-R-WG-01, at 12-13. WPAG argues that BPA has once again emphasized a policy objective over a statutory obligation and should change its Lookback recovery approach as it applies to Idaho Power. *Id*. at 13-15.

The Idaho PUC contends that BPA's present course for recovering Lookback Amounts is appropriate. IPUC Br., WP-10-B-ID-01, 3-5. The Idaho PUC argues that Staff's proposal still works because Idaho Power may become eligible for exchange benefits in the future. *Id*.

Idaho Power argues that BPA should maintain its current proposal for recovering the Lookback Amounts from its customers. IPC Br., WP-10-B-IP-01, at 4. Without conceding that the Lookback is appropriate, Idaho Power contends that the least harmful way of recovering the Lookback Amount from it is through prospective reductions in REP benefits. *Id*.

BPA Staff's Position

BPA Staff argues that it is not necessary to change the approach to Lookback recovery during this rate case for Idaho Power. Evans *et al.*, WP-10-E-BPA-40, at 38-54.

Evaluation of Positions

As discussed above, Staff proposes in this proceeding to recover and return the Lookback Amounts in a manner consistent with the prior rate proceeding. *See* Evans *et al.*, WP-10-E-BPA-19, at 3-4; Evans *et al.*, WP-10-E-BPA-40, at 40. One component of the decision in the WP-07 Supplemental rate proceeding was to return Lookback Amounts to preference customers by reducing prospective REP payments to the IOUs. *See* WP-07 Supplemental ROD (Conformed), WP-07-A-05, Section 9.3. BPA determined in the WP-07 Supplemental proceeding that this approach to returning the Lookback Amounts was the most appropriate, because it avoided the absurd result of the preference customers paying for their own refunds. *Id*. at 283. The amount of the repayment to the preference customers and the amount of the reduction in REP benefits to the IOUs was to be determined in each rate proceeding. *See* WP-07 Supplemental ROD (Conformed), WP-07-A-05, Section 9.3.

In reaching the decision to use REP benefits as the source of funds for the preference customers' refunds, BPA recognizes that recovering Idaho Power's Lookback Amount will present unique challenges. These challenges arise from the fact that Idaho Power has a substantial deemer balance (which is in dispute), and the fact that Idaho Power's ASC is generally so low that Idaho Power is not likely to participate in the exchange program during the rate period. Despite these challenges, BPA has made it clear that Idaho Power would still be required to return its Lookback Amount to BPA. As noted in the WP-07 Supplemental ROD:

> BPA is not allowing Idaho Power to retain its REP Settlement Agreement benefits without consequence. Rather, under BPA's simplified projections, Idaho Power does not repay its Lookback Amount within 20 years in part due to its significant deemer balance that is presently in dispute. Forman, *et al.*, WP-07-E-BPA-76, at 117-118. If an agreement is reached regarding the deemer balance, Idaho Power may at some future date qualify for REP benefits. *Id*. at 118. In such case, BPA will reduce Idaho Power's REP benefits in order to recover its Lookback Amounts. Thus, contrary to Cowlitz's statement, BPA is not ignoring Idaho Power's outstanding Lookback Amount.

WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 273.

Several parties in the present case object to Staff's proposal to use REP benefits as the source of funds to recover the Lookback Amounts because this method does not address the specific circumstances of Idaho Power. For example, APAC argues that a significant contributor to the failure to repay the Lookback Amount in seven years is the lack of any projected repayment by Idaho Power. APAC Br., WP-10-B-AP-01, at 8. APAC claims that the 7(b)(2) Study projects that Idaho Power's ASC will not exceed BPA's PF Exchange rate in any year through 2015. *Id*. at 8-9. As such, APAC contends that Staff states that they do not have any projection of when Idaho Power's REP benefits might begin. *Id*. at 9. APAC argues that in the WP-07

Supplemental ROD, BPA chose a repayment method that had no plan for repayment from Idaho Power for the foreseeable future. *Id*.

WPAG raises a similar argument in its Initial Brief. WPAG Br., WP-10-B-WG-01, at 8-9. Specifically, WPAG argues that, because Idaho Power does not qualify for REP benefits during the rate period, and, according to Staff's estimate, will not qualify for REP benefits anytime in the foreseeable future, Staff's approach will result in no repayment of any portion of the nearly $100 million Lookback Amount owed by Idaho Power. *Id*. WPAG reiterates this argument in its Brief on Exceptions. WPAG Br. Ex., WP-10-R-WG-01, at 12-13. WPAG claims that BPA has established beyond argument that its chosen methodology will not retrieve the Lookback Amount owed by Idaho Power for the "foreseeable future" and therefore imposes on BPA an affirmative duty to undertake the additional steps outlined in WPAG's brief, of which WPAG asserts BPA was already aware, to retrieve these illegally paid funds. *Id*.

BPA recognizes that, for this rate period, no portion of Idaho Power's Lookback Amount is forecast to be collected. Because of this fact, both APAC and WPAG assert that Idaho Power is expected to receive no REP benefits within the "foreseeable future," and therefore, BPA must develop a special recovery mechanism for Idaho Power. BPA disagrees. The information that APAC and WPAG rely upon to make this assertion is a BPA-developed model that projects an amortization schedule for the Lookback Amounts. Evans *et al.*, WP-10-E-BPA-40, at 41. This model uses several simplified assumptions to reach the forecasted payoff dates. Evans *et al.*, WP-10-E-BPA-19, at 11. One of those simplified assumptions is that Idaho Power's REP benefit level will remain constant at the FY 2011 level until FY 2015. Evans *et al.*, WP-10-E-BPA-40, at 41. Because Idaho Power is not expected to receive any REP benefits in FY 2011, the result of this modeling simplification is that Idaho Power's Lookback Amount is not reduced at all over the next six years. *Id*. While this assumption may be reasonable for modeling purposes, in reality, there are numerous factors that could occur between now and FY 2015 that could change this result. *Id*. As such, BPA does not agree that, because BPA's simplified model projects that Idaho Power will not pay off its Lookback Amounts within the immediate future, a complete change in the means and methods of recovering the Lookback Amounts from Idaho Power is in order.

APAC and WPAG both appear to assume that Idaho Power's absence from the REP will almost certainly last forever, and therefore, BPA must consider alternative arrangements to recovering Idaho Power's share of the Lookback Amount. This assumption is speculative at best. There are many variables that could change after this rate period that could result in Idaho Power becoming eligible to participate in the REP. For example, if Idaho Power were to experience a combination of low water conditions and a substantial increase in its production-related costs, it is entirely possible that Idaho Power's ASC could become high enough to make Idaho Power eligible to re-enter the REP. Evans *et al.*, WP-10-E-BPA-40, at 41-42; *see also* Cross Exam Tr. at 167. This is a real possibility considering the current press by many state utility commissions to require their regulated utilities to acquire more renewable and other resources. Evans *et al.*, WP-10-E-BPA-40, at 41-42. Illustrative of new resources that Idaho Power may bring on line that would likely raise its ASC is the Langley Gulch Power Plant, for which Idaho Power has filed an application with the Idaho PUC for a certificate of public convenience and necessity. IPC Br., WP-10-B-IP-01, at 6-7. The estimated cost for this project is $427.4 million. *Id*. at 7.

APAC's reliance on 7(b)(2) Study ASC forecasts is misplaced because those forecasts do not include the possibility of any of these factors. *See* WP-10-E-BPA-06, Appendices E, F, and G. In addition, BPA's approach of administrative offsets against future REP payments works well with the unique nature of the Residential Exchange Program. While Congress clothed the REP in commercial terms of a sale and exchange, the REP also has all the hallmarks of a public benefits program. The value of the REP is provided by BPA to the exchanging utility, which must then pass that benefit directly on to its residential and small farm customers. Unwinding the benefits provided and passed on to residential and small farm customers due to the now-invalidated REP Settlement Agreements is equitably accomplished by resorting to the structure of the REP program, meaning offsets against future benefits.

In short, BPA does not agree with the assertions of APAC and WPAG that it is a virtual certainty that preference customers are unlikely to ever see any of Idaho Power's Lookback Amount. There are many variables that could change that would bring Idaho Power back into the exchange, which would then lead to additional refund payments from Idaho Power to the preference customers. Evans *et al.*, WP-10-E-BPA-40, at 41-42.

APAC argues that Staff has not considered any other method for recovering the Lookback Amounts from Idaho Power, even though the WP-07 Supplemental ROD provides that alternate payment arrangements can be considered. APAC Br., WP-10-B-AP-01, at 9. APAC is mistaken. First, APAC misunderstands the WP-07 Supplemental ROD's reference to "alternative payment arrangements." To be clear, the full text of the WP-07 Supplemental ROD provides as follows: "Finally, BPA is open to alternative payment arrangements with the IOUs for recovery of their Lookback Amounts in less than seven years." WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 266. As the context makes clear, the reference to "alternative payment arrangements" was intended to give BPA's return and recovery construct flexibility to respond to *voluntary* requests by the IOUs to pay off their respective Lookback Amounts over a shorter period of time. Thus, if an IOU wished to provide BPA with a *faster* return of its Lookback Amount in cash or some other form of payment, BPA's proposal would allow this arrangement to be considered. This statement was in no way intended to suggest, as APAC argues, that BPA would consider in each rate case *involuntary* means of recovering the Lookback Amounts from the IOUs. APAC's interpretation of the WP-07 Supplemental ROD is incorrect.

Second, BPA already considered other ways of recovering the Lookback Amounts from the IOUs in the WP-07 Supplemental ROD and determined that reducing prospective REP benefits was the most appropriate way for recovering these funds. WP-07 Supplemental ROD (Conformed), WP-07-A-05, Section 9.3; Evans *et al.*, WP-10-E-BPA-40, at 42. For example, in the WP-07 Supplemental rate proceeding, several parties requested that BPA consider tapping other sources of revenue owed to the IOUs, such as payments under non-REP related contracts, to make the Lookback Amount payments. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 285. BPA ultimately rejected this proposal because it would have caused a significant disruption to BPA's business. *Id*. As noted in the ROD:

> …BPA foresees at least two serious problems with a policy that requires BPA to withhold payments from the IOUs on contracts unrelated to the REP to recover

> the Lookback. To begin with, BPA's ability to enter into new agreements and arrangements with the IOUs would be compromised. The IOUs would justifiably be cautious of entering any new arrangements with BPA because they would have no way of knowing whether BPA would claim a right to withhold payments under the new agreements to recover the Lookback Amounts. This result would seriously undermine BPA's ability to operate in a businesslike fashion.
>
> Furthermore, if BPA were to reduce future non-REP payments as a form of Lookback recovery, the IOUs might have a claim for initiating litigation against BPA for breach of contract. Such litigation could, in turn, threaten the continued viability of other non-REP agreements, which could cause BPA to lose potential lucrative arrangements. … BPA does not believe it either reasonable or necessary to incur this inordinate amount of legal and business risk to recover the Lookback Amounts if another viable alternative is available. As described above, Staff's proposal to reduce future REP benefits is such an alternative.

Id. Staff re-evaluated these concerns in its testimony and found them relevant to the present case. Evans *et al.*, WP-10-E-BPA-40, at 43. Thus, contrary to APAC's claim, Staff has considered alternative arrangements in this case. Based on this review, using prospective REP benefits owed to the IOUs remains the most reasonable course for recovering the Lookback Amounts.

APAC concludes its remarks on this topic with the argument that BPA must revise the repayment methodology to provide an effective method for commencing recovery from Idaho Power. APAC Br., WP-10-B-AP-01, at 8-9; APAC Br. Ex., WP-10-AP-R-01, at 7. Similarly, WPAG argues that, in light of the fact that BPA's approach to retrieve Lookback Amounts from the IOUs will not result in any repayment of the nearly $100 million owed by Idaho Power in the foreseeable future, BPA must take additional steps to obtain these funds. WPAG Br., WP-10-B-WG-01, at 9. WPAG contends that the money paid to Idaho Power under the REP Settlement was unlawfully charged to the preference customers and unlawfully provided to Idaho Power, and BPA has made a final determination of the Lookback Amounts that Idaho Power must repay. *Id*. As such, WPAG claims, BPA's duty as a Federal agency, as well as its obligation to its preference customers who paid for these unlawful benefits, requires it to do more than adopt an approach to recouping the Lookback Amounts that will not retrieve a dime of the Lookback Amount owed by Idaho Power. *Id*.

BPA disagrees that more must be done in this rate proceeding to collect Idaho Power's Lookback Amount. First, it is too early to tell whether the general approach to recovering the Lookback Amounts from IOUs adopted by the Administrator in the WP-07 Supplemental ROD is unworkable for Idaho Power. This rate proceeding is only the second rate case to address the recovery of the Lookback Amounts. Evans *et al.*, WP-10-E-BPA-40, at 42. While it is true that Idaho Power will not participate in the REP for FY 2010-2011, it is not possible for BPA to conclude that this trend will continue indefinitely into the future. *Id*. As noted before, there a many factors that could change that would result in Idaho Power returning to the REP. *Id*.

Second, BPA does not agree that it is depriving the preference customers of the repayment of Idaho Power's $100 million in Lookback refunds. Just because the preference customers are not receiving a portion of Idaho Power's Lookback Amount this rate period does not mean that Idaho Power's Lookback Amount disappears. Evans *et al.*, WP-10-E-BPA-40, at 49. Rather, BPA considers Idaho Power's Lookback Amount as an outstanding obligation that Idaho Power will have to contend with when it reenters the REP. *Id*. Thus, WPAG is incorrect in asserting that BPA's approach to recovering the Lookback Amounts will not retrieve "a dime" owed by Idaho Power. The simple fact is that for this rate period there are no benefits available to set off. This lack of benefits could very well change, however, in a future rate case.

Furthermore, even if Idaho Power takes longer to return its Lookback Amount than each of the other IOUs, the preference customers are not being financially injured, because they will receive interest in addition to the principal of Idaho Power's Lookback Amount. As the IPUC notes in its brief, the preference customers are not being disadvantaged if Idaho Power requires additional time to repay its Lookback Amounts because BPA is assessing Idaho Power the highest Treasury bill rate of all of the IOUs. IPUC Br., WP-10-B-ID-01, at 3-4. This interest rate will preserve the time value of the preference customers' refund. *Id*.

As noted earlier, equitable considerations also support BPA's decision to continue to use REP benefits as the source of funds for recovering Lookback Amounts. It is not lost on BPA that the IOUs individually did not benefit as a result of the payments made under the REP Settlement Agreements. The Administrator acknowledged this point when establishing the return and recovery proposal in the WP-07 Supplemental ROD:

> … the IOUs did not keep the monies paid under the REP settlements, but passed them on to residential consumers. For this reason, Staff structured the recovery of the Lookback Amounts through a reduction of future REP benefits paid, rather seeking repayments directly from the IOUs.

WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 259 (citations omitted).

BPA believes these equitable considerations still apply in this case and support continuing to use REP benefits as the source of funds for the Lookback Amounts. Moreover, Idaho Power appears to agree that, to the extent that a Lookback is in fact owed, Staff's approach is the most equitable way of recovering the Lookback Amounts. IPC Br., WP-10-B-IP-01, at 4. As noted before, BPA previously evaluated and rejected other alternatives for collecting the Lookback Amount from Idaho Power.

WPAG argues that BPA has a duty to take all actions required, including judicial action, if necessary, to retrieve the funds unlawfully paid to Idaho Power. WPAG Br., WP-10-B-WG-01, at 9. For support, WPAG cites *Fansteel Metallurgical Corp. v United States*, 172 F.Supp. 268, 270-71 (Ct. Cl. 1959). WPAG's reliance on *Fansteel* is misplaced. The issue in *Fansteel* was whether a number of affirmative defenses raised by the defendant precluded the government from asserting a counterclaim for the return of certain previous overpayments. *Id*. at 270. The Court denied the affirmative defenses and held that the government could bring an action for refunds against the defendant. *Id*. In holding for the government, the Court did not discuss whether the government had to choose one collection method over another. Rather, the government could take any legal means necessary to obtain the illegal funds. The instant case is no different. Here, BPA has decided that the most appropriate means of collecting Idaho

Power's Lookback Amount is through reductions in future REP benefits. Although Idaho Power will not receive any REP benefits during this rate period, this situation may change in subsequent rate cases. Thus, BPA believes it is reasonable to give its adopted approach time to work before abandoning it for some other method of recovery.

Even assuming, *arguendo*, that *Fansteel* could be construed as requiring BPA to bring a lawsuit against Idaho Power (which it cannot), it would be unreasonable for BPA to take such action for the equitable reasons discussed above. In addition, BPA's entire Lookback construct is the subject of pending litigation. Evans *et al.*, WP-10-E-BPA-40, at 53. Petitions challenging the decisions the Administrator made in the WP-07 Supplemental ROD were filed by a number of parties (including Idaho Power) in December of 2008. These petitions are currently pending before the Ninth Circuit. BPA believes that, even if it were otherwise reasonable to do so, it makes no sense to commence costly and time-intensive litigation against Idaho Power to recover its Lookback Amount while the very validity of the entire Lookback construct is waiting to be resolved in other pending litigation. Evans *et al.*, WP-10-E-BPA-40, at 53. Rather, the more logical approach is to maintain the recovery and return of the Lookback Amounts as expressed in the WP-07 Supplemental ROD until the Ninth Circuit resolves the issues with BPA's Lookback construct.

In its Brief on Exceptions, WPAG adds that BPA's inaction in the face of Idaho Power's outstanding liability is not only inconsistent with its general duty to take all actions required to retrieve funds illegally paid, it also flies in the face of the remand directive given to BPA in *Golden NW and PGE*. WPAG Br. Ex., WP-10-R-WP-01, at 13. By proceeding in the manner Staff proposed in this case, WPAG claims BPA is committing the same type of mistake of law that resulted in the *Golden NW* and *PGE* decisions in the first place. *Id*.

WPAG's arguments are not persuasive. The key concern expressed by the Ninth Circuit in *Golden NW* and *PGE* was that BPA's actions violated specific statutory directives in the Northwest Power Act. The instant case could not be more different. Unlike the *Golden NW* and *PGE* cases, there is no statutory language that directs BPA to recover overpayments from the IOUs in any particular way. Rather, BPA's organic statutes are completely silent on the issues of overpayments and refunds. Furthermore, the Ninth Circuit in *Golden NW* and *PGE* did not provide BPA with specific instructions on how BPA was to handle the recovery and returns of any refunds. Indeed, the only "law" that WPAG has been able to find on this subject is the general principle that government agencies must seek the return of overpayments. This is exactly what BPA is proposing to do in this case. As discussed above, BPA is not releasing Idaho Power from its obligation to repay its Lookback Amounts, but simply giving BPA's proposed recovery approach time to work. In no sense, then, is this like the violations the Ninth Circuit found in *PGE* or *Golden NW*. Furthermore, WPAG's arguments do not take into account the unique situation presented here: the invalidation of a government contract that has both commercial and public benefit attributes, and the remedies, if any, available to the government under such a situation.

WPAG then argues that, in this case, BPA appears to have limited the Lookback repayment obligation of investor-owned utilities to a "modest," or in the case of Idaho Power to a "non-existent," reduction in their Residential Exchange Program payments. WPAG Br. Ex., WP-10-

R-WG-01, at 14. WPAG's argument is without merit. BPA is reducing the IOUs' REP benefits by approximately *$163 million* over the WP-10 rate period. Lookback Recovery and Return Study, WP-10-FS-BPA-07, at Table 5. To characterize this reduction in REP benefits as "modest" is not only disingenuous but insensitive to the impact that this reduction will have on the residential and small farm customers of the IOUs. As to Idaho Power, BPA has already explained why it is not recovering Lookback Amounts from Idaho Power during this rate period.

WPAG next claims that BPA has made these "modest reductions" in REP benefits to "effectuate its policy objective of ensuring that no investor-owned utility will actually have to make payment to BPA to discharge its Lookback obligation." WPAG Br. Ex., WP-10-R-WG-01, at 14. Contrary to WPAG's unsubstantiated assertions, the record in this case clearly shows that BPA is making substantial progress in returning the overcharges to preference customers. As noted above, BPA is proposing to recover *$163 million* from the IOUs during this rate period. Lookback Recovery and Return Study, WP-10-FS-BPA-07, at Table 5. This is in addition to the *$424 million* that will have been returned to the preference customers by the end of FY 2009. *Id.* at Table 2. In total, by the end of the WP-10 rate period, BPA will have recovered from the IOUs and paid out to the preference customers approximately *$587 million*. *Id.*. If the current pace of repayment were to continue, Staff's simplified projections indicate that PGE and Puget are on track to return all of their Lookback Amounts by FY 2015, PacifiCorp by FY 2018, and Avista by FY 2023. *Id.* at Table 7. WPAG's mischaracterization of BPA's policy objectives and complete disregard for the evidence in this case undermine its credibility.

Decision

BPA's approach for recovering and returning the Lookback Amounts for FY 2010-2011 adequately addresses the situation presented by Idaho Power Company because Idaho Power may earn REP benefits in the future. In addition, the preference customers are not harmed under BPA's proposal, because interest continues to accrue and compound on Idaho Power's outstanding Lookback Amount balance.

Issue 2

Whether BPA should assume for ratemaking purposes that BPA will recover some or all of Idaho Power's Lookback Amount during the rate period.

Parties' Positions

WPAG argues that for purposes of setting rates, BPA should assume Idaho Power will return some portion of its Lookback Amount during the rate period. WPAG Br., WP-10-B-WG-01, at 9.

Idaho Power states that BPA should not accept that the Lookback Amount assessed to Idaho Power is a valid obligation of Idaho Power. IPC Br., WP-10-B-IP-01, at 2-3. Idaho Power argues that for purposes of this proceeding, BPA only has to determine whether it is likely that Idaho Power will be or will not be participating in the REP for FY 2010-2011. *Id.*

BPA Staff's Position

BPA Staff assumes that Idaho Power's Lookback is a valid obligation; however, because Idaho Power is not receiving any REP benefits during the rate period, Staff has assumed that Idaho Power will not make any payments towards its Lookback Amounts for ratemaking purposes. Evans *et al.*, WP-10-E-BPA-19, at 3-4; Evans *et al.*, WP-10-E-BPA-40, at 38-54.

Evaluation of Positions

WPAG argues that, for purposes of setting rates in this proceeding, BPA should assume that it will take the "necessary actions" to enforce the legally valid and binding Lookback Amount owed by Idaho Power consistent with the seven year repayment period BPA adopted in the WP-07 Supplemental proceeding. WPAG Br., WP-10-B-WG-01, at 9. WPAG contends that enforcing Idaho Power's Lookback Amount repayment obligation will return some portion of the nearly $100 million owed by Idaho Power to BPA's preference customers. *Id.* WPAG contends that this will lower the effective cost of the power that the COUs buy from BPA during the rate period, and help them survive the recessionary economy they currently face. *Id.*

Idaho Power, on the other hand, counters that BPA should not accept as fact that the Lookback is a valid obligation of Idaho Power, and that BPA should not take the necessary actions to enforce repayment of this obligation. IPC Br., WP-10-B-IP-01, at 2. Idaho Power says that it would be imprudent for BPA to speculate for ratemaking purposes on legal rights that BPA has outside of a rate case to collect alleged Lookback Amount balances. *Id.* According to Idaho Power, BPA determined in the WP-07 Supplemental Record of Decision that it may properly assess the relevance and significance of contracts in ratemaking, based on its own independent assessment, but that such determinations do not constitute a binding adjudication of contract rights. *Id.* Idaho Power asserts that, for purposes of determining rates for FY 2010-2011, BPA should not engage in the speculative exercise of predicting the outcomes of litigation concerning contract disputes and then assess the likelihood that BPA could successfully exercise remedies that result from such outcomes. *Id.*

The debate between Idaho Power and WPAG regarding the "legal validity" of the Lookback Amount for purposes of setting rates is largely beside the point. BPA asserted in the WP-07 Supplemental ROD that it has the right to collect the Lookback Amounts from the IOUs. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 256-260. That is why Staff proposes to reduce the IOUs' REP benefits by approximately $80 million in both FY 2010 and FY 2011 and send these funds to the appropriate preference customers. *See* Evans *et al.*, WP-10-E-BPA-19; Evans *et al.*, WP-10-E-BPA-40, at 44; Lookback Recovery and Return Study, WP-10-FS-BPA-07, at Table 5. If Staff believed the Lookback Amounts were "invalid obligations," Staff would obviously not have proposed to reduce any of the IOUs' REP benefits to pay back the Lookback Amounts in this rate period. *Id.*

BPA's view of Idaho Power's Lookback Amount is no different. Evans *et al.*, WP-10-E-BPA-40, at 44. Staff assumes that Idaho Power has an outstanding Lookback Amount as of the end of FY 2009 of $107 million that is available to reduce any REP benefits legally owed to it. *Id.*; *see also* Lookback Recovery and Return Study, WP-10-FS-BPA-07, page 6. However, because BPA's current projections indicate that Idaho Power is not expected to receive any benefits during the rate period, Staff also assumes that Idaho Power will not be making any payments towards its Lookback Amounts this rate period. *Id.* Whether Staff's assumptions regarding Idaho Power's Lookback Amount will ultimately prevail is an issue for the courts to decide, not BPA or the parties in this case.

WPAG contends that BPA should assume for ratemaking purposes that BPA will take the "necessary actions" to enforce the Lookback Amount owed by Idaho Power consistent with the seven-year repayment period BPA adopted in the WP-07 Supplemental proceeding. WPAG Br., WP-10-B-WG-01, at 9. WPAG Br. Ex., WP-10-R-WG-01, at 11-13. WPAG's Initial Brief does not elaborate on what actions BPA should take in order to recover additional funds from Idaho Power. However, in its Brief on Exceptions, WPAG suggests that these "necessary actions" consist of BPA negotiating with Idaho Power a payment schedule for the return of the overcharges just as BPA would do with any utility in arrears. *Id. at 12*. If these efforts fail, WPAG argues, BPA must take Idaho Power to court, regardless of whether Idaho Power has the funds or not, because BPA's collection efforts must be "immediate and remorseless." *Id.* at 12. WPAG claims these steps are "not new" to BPA and should already have been undertaken by BPA. *Id.*

WPAG's suggestion that BPA approach Idaho Power's Lookback Amount as simply another billing dispute is unhelpful. First, WPAG knows very well that negotiating a payment schedule with Idaho Power is a futile effort, because Idaho Power disputes that it owes BPA anything. Obviously, BPA would have pursued negotiations with Idaho Power over the return of its Lookback Amount had Idaho Power expressed any interest in such an approach. The facts of this record, however, are clear that Idaho Power has no intention of negotiating a separate payment schedule for the return of its Lookback Amount at this time. It would make no sense for BPA to waste its time and money on negotiating the return of a payment that Idaho Power does not believe it owes.

Second, WPAG's suggestion is seriously flawed because it does not take into account the fact that BPA's Lookback construct is currently the subject of pending litigation before the Ninth Circuit. As WPAG is well aware, preference customers and the IOUs have filed petitions challenging BPA's decisions in the WP-07 Supplemental ROD. An adverse decision by the Ninth Circuit on any one of a number of issues made in the WP-07 Supplemental ROD could dramatically change the amount (if any) of refunds that Idaho Power and the other IOUs must repay. In light of this uncertainty, BPA does not believe it would be a prudent business decision or an appropriate use of the court's limited resources to commence concurrent time-intensive and costly litigation against Idaho Power while the very validity of the Lookback Amounts remains unresolved in pending litigation. Evans *et al.*, WP-10-E-BPA-40, at 48.

Third, equitable considerations also support BPA's decision to continue to use REP benefits as the source of funds for recovering Lookback Amounts. As noted before, it is not lost on BPA that the IOUs individually did not benefit as a result of the payments made under the REP Settlement Agreements. The Administrator acknowledged this point when establishing the return and recovery proposal in the WP-07 Supplemental ROD:

> … the IOUs did not keep the monies paid under the REP settlements, but passed them on to residential consumers. For this reason, Staff structured the recovery of

> the Lookback Amounts through a reduction of future REP benefits paid, rather than seeking repayments directly from the IOUs.

WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 259 (citations omitted). As discussed above, BPA believes these equitable considerations still apply in this case and support the continued use of REP benefits as the source of funds for the Lookback Amounts. Furthermore, WPAG's posturing evidences no appreciation for the very significant risk BPA would face were BPA to bring suit against Idaho. There are numerous legal and equitable defenses that Idaho Power could raise against a claim for return of funds provided under the REP Settlement Agreements. Resolving these issues could take years of contentious and potentially unsuccessful litigation. In contrast, BPA's approach allows preference customers to receive immediate refunds if and when Idaho Power were to return to the REP.

WPAG also argues that BPA should assume that Idaho Power would return "some portion" of the nearly $100 million owed by Idaho Power to BPA's preference customers during the rate period. WPAG Br., WP-10-B-WG-01, at 9. In its Brief on Exceptions, WPAG argues that BPA should assume the collection of two-sevenths of Idaho's Lookback Amount for this rate period. WPAG Br. Ex., WP-10-R-WG-01, at 14. WPAG concludes that this assumption will lower the effective cost of power COUs will pay to BPA during the rate period, and help them survive the recessionary economy they currently face. WPAG Br., WP-10-B-WG-01, at 9. Thus, WPAG would have BPA assume in setting rates that Idaho Power would pay BPA roughly *$30 million* in Lookback Amount payments by the end of FY 2011. Evans *et al.*, WP-10-E-BPA-40, at 45.

WPAG's proposal is fundamentally flawed and unreasonable. WPAG's assumption would place an untenable level of pressure on the proposed rates. Evans *et al.*, WP-10-E-BPA-40, at 45. BPA's current approach to returning Lookback Amounts results in no net impact on BPA's rates. *Id.* For every dollar that is credited to the preference customers as a refund, a corresponding dollar is reduced from the payments being made to the IOUs. *Id.* This balance is essential to ensuring that payment of the Lookback Amounts does not result in BPA increasing its rates. *Id.*

WPAG's suggestion would completely upend this important balance. *Id.* WPAG is requesting BPA to make a $30 million advance payment to the preference customers based on the assumption that BPA will recover these funds from Idaho Power through some yet-unidentified action. *Id.* The risk associated with such assumption is substantial. *Id.* BPA has no basis for assuming that such claim could be made and resolved by the end of the rate period. *Id.* at 48. As noted by Staff in testimony:

> …even if we could articulate a basis for assuming BPA should recover funds from Idaho Power, there is absolutely no way we could say with certainty that such resolution would occur within the terms of this rate period. Predicting when these payments would be made is even more precarious when considering that BPA's WP-07 Supplemental rate case is currently in litigation. While we cannot provide legal opinions about the nature or state of the case, it is common knowledge that resolving complex litigation in today's courts takes a significant amount of time. If the size of BPA's record of decisions is any indication of the complexity of the issues involved with the Lookback, then we assume the 700-plus page ROD BPA issued in the WP-07 Supplemental rate case will be one of

> the more difficult BPA-related cases for the Court to decide. Assuming that all of the litigation involving BPA's decisions in that document will be resolved with the result that Idaho Power will have paid some or all of its Lookback Amount by the end of the rate period defies credulity. We simply do not know when this will occur, and assuming otherwise is not an appropriate rate case assumption.

Id.

BPA rejects WPAG's call for BPA to set rates based on a wholly unsupportable and speculative assumption that BPA will be paid at some unknown future date based on some unknown claim.

WPAG's proposal is even more unreasonable when considering that it places most of the risk of non-payment by Idaho Power on the rates of the preference customers that would receive the monies. Because Idaho Power is not receiving any REP benefits and is not expected to receive REP benefits during the rate period, the initial source of WPAG's $30 million advance will have to be BPA's financial reserves. *Id*. BPA's reserves will remain the source of these payments until BPA receives payment from Idaho Power pursuant to the "necessary actions" WPAG believes BPA should take. *Id*. at 46. Indeed, WPAG itself recognizes that, under its proposal, BPA's reserves will remain the source of these funds:

> BPA has treated the payments of the Lookback Amounts as a pass through to its preference customers as a credit on their monthly power bill. In that regard it operates in the same manner as the Residential Exchange payments made to the IOUs. If BPA makes the Lookback payments to the preference customers in the amounts owed by Idaho Power during the rate period and for some reason not articulated in the data request the Lookback Amounts owed by Idaho Power are not collected in the rate period, the result would be a reduction in BPA's financial reserves that would be reflected when BPA's rates are next set.

Response to Data Request No. BPA-WG-04; *see also* Evans *et al.*, WP-10-E-BPA-40, at 46. These reserves, and the reserves generated by BPA's proposed rates, provide the necessary assurance of cost recovery under Northwest Power Act section 7(a).

As recognized by WPAG in the above data response, unless BPA is able to recover the funds from Idaho Power by the end of the rate period, BPA will have to replenish its reserves with higher rates in the next rate period. Evans *et al.*, WP-10-E-BPA-40, at 46. In addition, having fewer reserves also may cause higher rates in the short term because it increases the chances that a CRAC will trigger during the rate period. *Id*. In both cases, the net effect is that BPA's rates would be higher in order to cover the shortfall in reserves, resulting in the perversity of the preference customers paying for their own refunds. *Id*. BPA specifically rejected this approach in the WP-07 Supplemental ROD:

> All costs (regardless of their source) must eventually be included and recovered through the cost-based rates charged to BPA's regional firm power customers, including preference customers. In general, if BPA were to make payments to the COUs from reserves available for risk, BPA would likely need to subsequently increase the COUs' rates to replenish such reserves, all else being equal. Payments out of reserves would likely result in higher rates to the COUs because

> the remaining reserves for risk would probably be too low to support BPA's Treasury Payment Probability (TPP) standard. Thus, Planned Net Revenues for Risk (PNRR) would need to be added to the revenue requirement, and the PF Preference rate would increase. The end result is that the use of reserves to pay Lookback Amounts would result in the COUs effectively paying for their own remedy through higher future rates, all else being equal.

WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 283 (internal citations omitted).

BPA does not agree that it would be reasonable in any way to assume for ratesetting purposes that BPA will recover funds from Idaho Power during the rate period. To do so would expose BPA to untoward financial risk and place an untenable level of pressure on the PF rates. If BPA adopts WPAG's proposed assumption, but is unable to obtain funds from Idaho Power by the end of the rate period, the preference customers would end up paying for their own refund. WPAG and other preference customers would obviously not want this result, so BPA continues to believe that WPAG's recommendation is faulty.

Finally, the fact that BPA is not adopting WPAG's assumption for ratesetting purposes in no way prejudices the preference customers if, in fact, Idaho Power makes Lookback Amount payments to BPA. BPA's assumptions in this case relate to only the collection and return of Lookback Amounts as they relate to REP benefits. Evans *et al.*, WP-10-E-BPA-40, at 49. If Idaho Power were to return Lookback Amounts to BPA during the rate period, BPA would have the option of returning these funds to preference customers as additional credits on their bills. *Id*. at 49-50. Thus, the fact that BPA is not "assuming" these payments will be made does not in any way impair the Administrator's ability to make additional Lookback Amount payments to the preference customers if additional Lookback Amounts are, in fact, recovered during the rate period. *Id*. at 50.

Idaho Power argues that it is unnecessary for BPA to speculate on how the alleged Lookback Amount and deemer balance that are attributed to Idaho Power may be ultimately disposed of. IPC Br., WP-10-B-IP-01, at 3. Idaho Power argues that it has not executed an RPSA, and until there are final determinations by the courts or settlements of legal issues surrounding the alleged Idaho Power Lookback Amount and deemer balance, it is unlikely that Idaho Power will sign an RPSA. *Id*. Additionally, Idaho Power contends that it is reasonable to assume that Idaho Power would request the appropriate RPSA only at such time as Idaho Power's Average System Cost exceeds BPA's Priority Firm Rate. *Id*. Because Idaho Power has not signed an RPSA, it is not necessary for BPA to determine the precise Lookback Amount attributable to Idaho Power. *Id*. The Lookback Amount attributed to Idaho Power is not necessary for purposes of determining rates in this proceeding. *Id*.

BPA concurs in part with the arguments made by Idaho Power. BPA agrees with Idaho Power's observation that it is unnecessary for BPA to speculate how Idaho Power's Lookback Amount balance may be disposed of in forums outside of the rate case. This matter is unrelated to BPA's ratemaking decisions. In addition, BPA agrees that it is reasonable to assume that Idaho Power would request to participate in the exchange only when its ASC is above BPA's PF Exchange rate. This assumption makes sense, because Idaho Power would obviously not want to enter the exchange program only to incur additional deemer balances under the terms of the balancing account provisions in the RPSA.

BPA disagrees with Idaho Power's argument that it is unnecessary to calculate a Lookback Amount for Idaho Power as part of the rate proceeding. As BPA explained above, while Idaho Power is not participating in the REP today, this situation may change in the future. If it does, BPA intends to reduce Idaho Power's REP benefits to recover Idaho Power's outstanding Lookback Amount. BPA committed in the WP-07 Supplemental ROD to determine the amount of REP benefits to pay toward an IOU's Lookback Amount in BPA's rate proceedings. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 258-259. Consistent with that decision, if Idaho Power were to come back into the REP, BPA would need to have Idaho Power's Lookback Amount in BPA's rate records to make the appropriate adjustments. In addition, as a practical matter, restating Idaho Power's Lookback Amount each rate period is reasonable, because it ensures that the outstanding balance is properly calculated. By having Idaho Power's Lookback Amount restated in BPA's rate records, Idaho Power, BPA, and the preference customers will have a ready source for all of the calculations that BPA has conducted to reach Idaho Power's outstanding balance. If any problems or concerns are identified with BPA's calculations, then the issue can be resolved as part of BPA's rate case process. For these reasons, then, BPA believes it is reasonable to continue to calculate Idaho Power's Lookback Amount in BPA's rate cases.

Decision

BPA will not assume for ratemaking purposes that BPA will recover some or all of Idaho Power's Lookback Amount during the rate period. BPA will, however, continue to calculate Idaho Power's Lookback Amount as part of BPA's rate proceedings.

15.5 Interest Rate on Lookback Balances for FY 2010-2011

Issue 1

Whether the interest rate paid by the IOUs on the unpaid balances of their Lookback Amounts should contain a risk premium.

Parties' Positions

APAC argues that the interest rate applied to the unpaid Lookback balance should include a risk premium to cover the risk of non-payment of the principal. APAC Br., WP-10-B-AP-01, at 9-11.

The IOUs, the OPUC, and the Idaho PUC argue that BPA's proposed interest rate is appropriate and urge BPA to reject suggestions that a risk premium be added to the interest rate applied to the unpaid portion of the Lookback Amounts. IOU Br., WP-10-B-JP1-01, at 92-94; OPUC Br., WP-10-B-PU-01, at 14-15; IPUC Br., WP-10-B-ID-01, at 3-4.

BPA Staff's Position

The interest rate applied to the unpaid balance of each IOU's Lookback Amount should not include an additional risk premium. Evans *et al.*, WP-10-E-BPA-19, at 12; Evans *et al.*, WP-10-E-BPA-40, at 33-38.

Evaluation of Positions

In the WP-07 Supplemental ROD, WP-07-A-05, the Administrator determined that the unpaid balances of each IOU's Lookback Amount would accrue interest at a rate equal to the U.S. Treasury bill rate. WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 213-216. In reaching this decision, the Administrator explained that the Treasury bill rate was an appropriate level of interest because it was "a neutral rate of interest that does not advantage or disadvantage either the [preference customers] or the IOUs." *Id*. at 214. The Administrator also committed to recalculate the interest rate each rate period to correspond to the expected term of repayment. Thus, if an IOU's Lookback Amount will be totally repaid in seven years, the seven-year T-Bill will be used to calculate interest. If an IOU's Lookback Amount will be repaid in a longer period, then a T-Bill interest rate matching the longer repayment period will be used. *Id*. at 215.

The Administrator's decision to use the Treasury bill rate as the rate of interest on the Lookback Amount balances was challenged by several parties in the WP-07 Supplemental rate proceeding. APAC argued that the preference customers should receive a higher "risk adjusted" rate of interest to reflect the risk that they may not recover the entire Lookback Amount from the IOUs. *Id*. at 214. APAC suggested an interest rate of 11.5 percent, which APAC claimed would correspond to the equity-like position that preference customers are in as they wait for their refunds from BPA. *Id*. The Administrator rejected this argument in the WP-07 Supplemental ROD, explaining that preference customers are fundamentally not in the same position as equity shareholders of a publicly traded company who bear substantial risk of no return. *Id*. at 214-215.

In the Initial Proposal of this case, Staff proposes to continue using the U.S. Treasury bill rates determined in the WP-07 Supplemental Rate Proceeding as the interest rates applicable to the remaining IOU-specific Lookback Amount balances. Evans *et al.*, WP-10-E-BPA-19, at 12. The level of these interest rates is discussed in section 2.5 of the FY 2002-2008 Lookback Study, WP-07-FS-BPA-08, at 9-10. *See also* Table 5 in Lookback Recovery and Return Study, WP-10-FS-BPA-07, at 10.

In response, APAC reasserts its position that the appropriate interest rate should be an equity-based interest rate of 11.5 percent. APAC Br., WP-10-B-AP-01, at 9-11. APAC raises both new and old arguments to support this position.

APAC first argues that adequate interest rates are required to ensure that the reimbursements to preference customers fully compensate them for all risks. APAC Br., WP-10-B-AP-01, at 5. To support this statement, APAC cites to *Gore, Inc. v. Glickman*, 137 F.3d 863 (5th Cir. 1998), *Waterview Management Co. v. FDIC*, 257 F.Supp.2d 31 (D. D.C. 2003), and *In re Sophisticated Communications, Inc.*, *slip copy*, 2007 WL 3216613, Bkrtcy. S.D. Fla., October 24, 2007. APAC's reliance on the aforementioned cases is misplaced. First, none of the cases APAC cites support its conclusion that BPA must adopt an equity-based interest rate. All three cases address the appropriateness of prejudgment interest in situations where the applicable statutes were silent. As such, they do not speak to BPA's alleged duty to provide preference customers with the "risk adjusted" interest rate advocated by APAC.

Furthermore, the cases APAC relies upon actually support Staff's proposal. In *Gore*, the key issue was whether a party could receive prejudgment interest on a refund claim under the provisions of the Agriculture Marketing Agreement Act of 1937 ("AMAA"). 137 F.3d 863 (5th Cir. 1998). Even though the statute was silent, the Court held that prejudgment interest was appropriate because it furthered the congressional policies underlying the AMAA. *Id*. at 866. Specifically, the Court explained that awarding prejudgment interest preserved the "time value of money" of the milk handler's claim, which furthered the goal of fully compensating injured milk handlers under the AMAA. *Id*. at 868. When considering the interest rate that would be used to preserve this claim, the Court noted that "[i]t is unlikely that prejudgment interest on a refund owed to the handler would exceed the postjudgment interest rate under 28 U.S.C. § 1961, which, for example, is currently only 5.407% per annum." *Id*. at 869, FN 5. The statutory postjudgment interest rate referenced by the Court in *Gore* was, in fact, the *Treasury bill rate*. *See* 28 U.S.C. § 1961.

In *In re Sophisticated Communications*, the Court awarded the bankruptcy Trustee prejudgment interest on a claim that sought to recovery a preferential transfer made by the debtor to a bank. 2007 WL 3216613, Bkrtcy. S.D. Fla., October 24, 2007. The Court granted the Trustee's request for interest to ensure the estate received the "time value of money" of the unlawful transfer. *Id*. at 3. When determining the level of interest to be applied, the Trustee asked the Court to use the prime rate. *Id*. at 4. The Court denied the Trustee's request and opted instead to use the Treasury bill rate because "[t]he majority of courts have determined the prejudgment interest rate in preference actions in accordance with 28 U.S.C. § 1961, which provides for postjudgment interest in federal actions at the *Treasury bill rate*." *Id*. (citations omitted) (emphasis added).

The third case APAC cites, *Waterview Management,* is inapposite to the current facts. 257 F.Supp.2d 31 (DDC, 2003). In *Waterview Management,* the Court decided that prejudgment interest should apply to a claim against the FDIC. *Id*. 34-35. In so holding, the Court did not discuss the "adequacy" of the prejudgment interest rate. *Id*. The only discussion in the Court's opinion on interest related to the level of the postjudgment interest rate, wherein the Court once again identified the statutory Treasury bill rate as the applicable rate. *Id*. at 37.

In short, as shown by the very cases APAC cites, when determining the level of prejudgment interest to award to parties, the courts routinely turn to the Treasury bill rate. BPA properly decided to apply the Treasury bill rate in the WP-07 Supplemental ROD when deciding what interest rate to apply to the unpaid Lookback Amount balances, and this is what BPA is proposing to do again in this case. Staff's proposal to retain the Treasury bill rate as the measure of interest for the outstanding Lookback Amounts is appropriate and in accordance with the cases discussed above.

APAC next argues that the interest rate on the unpaid Lookback Amount balances must compensate preference customers for both "the time value of money" and the "risk of nonpayment of principal." APAC Br., WP-10-B-AP-01, at 9. The Treasury bill rate, according to APAC, is a "risk free" rate that compensates the preference customers for only the time value of money, but not for risk of nonpayment. *Id*. APAC notes that in the WP-07 Supplemental rate proceeding, the risk of repayment was uncertain, justifying a higher interest rate. *Id*. APAC now contends that the risk is even higher in this case. *Id*. To support this statement, APAC sets forth two new "uncertainties" that it claims make the return of the Lookback Amounts even more precarious in this case, and therefore, require BPA to reconsider its use of the Treasury bill rate.

First, APAC argues that the method for repayment remains tied to the amount of REP benefits, which changes in each rate case based on ASCs and BPA's costs. *Id*. at 10. APAC argues that there is uncertainty inherent in this methodology. *Id*. Even for those utilities that are projected in this case to repay within seven years, APAC claims there is no guarantee that there will continue to be sufficient REP benefits in succeeding rate cases. *Id*. APAC contends that demonstrating and compounding this uncertainty is the fact that repayment by Avista and PacifiCorp will be delayed. *Id*. APAC contends that there is additional uncertainty because there is no prospect for Idaho Power to even begin repayment. *Id*.

These "uncertainties" APAC outlines in its brief, however, are not new. All of the events identified by APAC existed when BPA first formulated the structure of the recovery and return of the Lookback Amounts. BPA candidly acknowledged in the WP-07 Supplemental ROD that it could not guarantee that the repayments from the IOUs would be made in accordance with BPA's timetable. WP-07 Supplemental ROD, WP-07-A-05, at 215. Indeed, it was *because* of this uncertainty that BPA agreed to use a more robust interest rate, the Treasury bill rate, as the going-forward interest rate on the Lookback Amounts. *Id*. BPA's use of the Treasury bill rate was not a requirement. As noted in the WP-07 Supplemental ROD, BPA has *no obligation* to supply the preference customers with interest on their respective refunds. *Id*. at 208. Nevertheless, as a matter of policy, BPA decided to provide the preference customers with some interest to preserve the value of the Lookback Amounts. *Id*. For the period covering FY 2002 through FY 2009, BPA determined that the applicable interest rate should be inflation. *Id*. at 212. This inflation-based rate could have been used as the going-forward measure of interest for all post-FY 2009 periods, including FY 2010-2011. However, BPA decided not to use inflation in subsequent periods because of the arguments APAC and other parties raised concerning the financial harm to their refunds if the return of the Lookback Amounts is delayed. Thus, the Administrator noted in the final ROD that

> BPA concurs that it cannot guarantee that the repayments from the IOUs will be made in the time allotted … It is because of this potential risk that BPA decided to use a more robust interest rate in the going-forward period than the interest rate used for the Lookback period (2002-2008) … [T]he T-Bill interest rate corresponding to the expected term of repayment of the Lookback Amounts appropriately compensates the COUs for the delay in returning the Lookback Amount over BPA's proposed payment term.

Id. at 215 (internal citations omitted).

BPA's decision to apply a higher level of interest against the remaining balances of the IOU's Lookback Amount in future rate cases was adopted to address the very issues APAC raises in its brief, namely, the possibility that the return of the Lookback Amount for certain utilities may be further delayed. As such, the fact that BPA in this case is still not projected to recover Avista's and PacifiCorp's Lookback Amounts within seven years, or not recover any funds from Idaho Power, does not fundamentally change the risks that already existed when BPA first adopted the Treasury bill rate in the WP-07 Supplemental rate proceeding. BPA knew there would be uncertainty in the timing of the repayment of the Lookback Amounts to the preference customers. BPA's method for addressing this uncertainty was to provide additional compensation to the preference customers through a higher interest rate, which came in the form of the Treasury bill rate. APAC's alleged new "uncertainties" have already been addressed.

APAC argues that a second "uncertainty" threatening the preference customers' refunds stems from how BPA balances the competing goals of paying IOUs half of the calculated REP benefits and maintaining a schedule to amortize the Lookback Amounts. APAC Br., WP-10-B-AP-01, at 10. APAC claims that this determination can change from case to case and delay the otherwise-expected repayments to the preference customers. *Id*. In response, BPA notes that this alleged "uncertainty" also existed in the prior rate proceeding. As explained in the discussion of Issue 1 of this chapter, Staff's proposal for returning and recovering the Lookback Amounts balances two objectives: returning the Lookback Amounts to the preference customers in a reasonable time and providing a reasonable level of REP benefits to the residential and small farm customers of the IOUs. This "balancing" approach to the return of the Lookback Amounts has always been a component of BPA's recovery and return of the Lookback Amounts. To the extent that BPA extends the time period for repaying the Lookback Amounts in any particular rate period, the preference customers are protected by the application of the Treasury bill interest rate. As discussed above and in the WP-07 Supplemental ROD, this rate compensates the preference customers for the time value of money associated with any delays in the return of the Lookback Amounts.

In addition, BPA does not agree with APAC's assertion that the preference customers are exposed to more risk of not receiving their Lookback Amount simply because the Administrator has discretion to determine the amount of refunds to recover each rate period. APAC's concern ignores the fact that this discretion enables the Administrator to increase, as well as decrease, the pace of repayment. For the current rate period, REP benefit payments are at a level roughly equal to the level the payments were in the WP-07 Supplemental rate proceeding. As explained in Issue 1 above, this factor, among others, militates in favor of maintaining the previous rate case decisions regarding the recovery and return of Lookback Amounts. In subsequent years, however, REP benefits could increase substantially. In that event, the Administrator has the discretion (though not the obligation) to set off more of the IOUs' Lookback Amounts, which would result in a faster return of refunds to the preference customers. Contrary to APAC's argument, the flexibility afforded to the Administrator in establishing the level of refunds recovered in each rate period does not automatically mean that the preference customers are subject to more risk of nonpayment. This flexibility can be used to increase, as well as decrease, the pace of repayment, depending on the unique facts and circumstances of each rate case.

APAC concludes its arguments against Staff's proposed interest rate with a recitation of its previous position in the WP-07 Supplemental rate proceeding. APAC Br., WP-10-B-AP-01, at 10. APAC contends that in Staff's proposal, the claims for repayment to preference customers "do not have priority" on the funds for the REP benefits. *Id*. Without qualification or exception, APAC claims that Staff would give higher priority to the payment to the IOUs of at least 50 percent of their REP benefits. *Id.* This assertion, however, is patently incorrect. To support this statement in its brief, APAC cites to the cross examination transcript, where the following colloquy took place:

> Q. (Mr. Brookhyser) So assuming it produces a change in the REP benefits and PacifiCorp's REP benefits are lower than the amount in Column A, would BPA staff recommend that the lookback payment in Column C be reduced proportionally?
>
> A. (Mr. Young) Are you asking in this kind of limited hypothetical if that would be the case? Because the REP benefits are a function of the model here. The model runs a 7(b)(2) test and the final ASCs that will be determined by the Administrator for this proceeding.
>
> Q. I'm asking you to assume that the run is made that the REP benefits are actually reduced.
>
> A. (Mr. Forman) Well, without knowing -- you're saying if the $47.21 million was smaller, correct?
>
> Q. Correct.
>
> A. (Mr. Forman) Well, not knowing how much smaller or knowing any other circumstances that would change with the final numbers, I would say there's a reasonable chance that we would make the same calculation we did in the proposal, which would be to preserve this 50 percent threshold, but I can't say without considering it or the panel, I don't believe, would say without considering it in light of the various objectives we've outlined in our testimony.

Cross Ex. Tr. at 162-163.

As the foregoing discussion makes clear, Staff did *not* say they would in every circumstance give priority to the objective of paying the IOUs over returning the Lookback Amount to the preference customers. Rather, BPA would adopt a final proposal "in light of the various objectives [Staff have] outlined in … testimony." *Id.* at 163. Those objectives include the seven factors originally discussed in BPA's WP-07 Supplemental rate proceeding, and discussed again in testimony in this case, all of which turn on the unique facts and circumstances of each rate case. Evans *et al.*, WP-10-E-BPA-19, at 8-12. BPA's commitment to evaluating each factor on a case-by-case basis *does not* establish a hard and fast "priority" in the payment of REP benefits over the return of Lookback Amounts, as alleged by APAC. Rather, it allows the Administrator flexibility to adjust the return in an equitable manner based on the particular circumstances of each rate period.

Continuing with its fictitious priority assumption, APAC then argues that the effect of this alleged lower priority is that the preference customers have additional risk of delayed or failed repayment. APAC Br., WP-10-B-AP-01, at 10. APAC then reargues its inapposite comparison between the risks of the preference customers waiting for refunds and the risks associated with stakeholders in a private company. *Id.*; *see also* WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 213-216. Based on this comparison, APAC claims that the preference customers have a priority akin to that of junior debt or of equity holders, who are paid only if cash remains after payment of the senior creditors. APAC Br., WP-10-B-AP-01, at 10. APAC concludes that the interest rate of 11.5 percent proposed by APAC in the WP-07 Supplemental rate proceeding remains an appropriate interest rate for the unpaid balance of the Lookback Amount. *Id*. at 10-11.

The IOUs, IPUC, and OPUC urge BPA to reject APAC's renewed arguments for a risk-adjusted rate. The IOUs argue that a "risk component" should not be added to any interest rate on unrecovered Lookback Amounts, because the argument for the addition of a risk component to that interest rate is based on a faulty analogy that confuses the recovery of Lookback Amounts through reductions in REP benefits with situations in which risk premiums intended to attract capital from investors are paid. IOU Br., WP-10-B-JP1-01, at 93-94. The IPUC raises a similar point, arguing that the accrual of interest on Lookback Amounts sufficiently represents the time value of money. IPUC Br., WP-10-B-ID-01, at 4. Finally, the Oregon PUC, after commenting on APAC's position with regard to a risk component, stated that: "The Administrator should reject these renewed arguments in this proceeding." OPUC Br., WP-10-B-PU-01, at 14. The OPUC also stated that, "…the Administrator has already selected interest rates that appropriately compensate consumer-owned utilities for risk of non-payment. APAC offers no persuasive reason for the Administrator to revisit those decisions in this case." *Id*. at 14-15.

BPA concurs with the observations of the IOUs, IPUC, and the OPUC. BPA explained in the WP-07 Supplemental ROD why the Treasury rate is the most appropriate rate and why APAC's "risk-adjusted" rate is not reasonable. WP-07 Supplemental ROD, WP-07-A-05, at 213-216. In addition, as discussed above, BPA already addressed in the WP-07 Supplemental ROD the problems with APAC's comparison of preference customers and equity shareholders. *Id*. BPA will not reiterate those arguments here. Pursuant to the Hearing Officer's Incorporation Order, all litigants' previous arguments on this issue have been preserved. Order Incorporating Arguments and Evidence From the WP-07 Supplemental Record Into the WP-10 Wholesale Power Rate Adjustment Proceeding, WP-10-HOO-09. APAC's comparison of preference customers as equity shareholders is inapposite to determining the applicable rate of interest. Evans *et al.*, WP-10-E-BPA-40, at 3. As APAC properly notes in its brief, the Treasury rate compensates the preference customers for the time value of money associated with their respective refunds. APAC Br., WP-10-B-AP-01, at 9. APAC has presented no new evidence or arguments that persuade BPA that a different level of interest is warranted in this case.

Decision

The Treasury bill interest rate, without an additional risk premium, is the appropriate rate to charge the IOUs on unpaid balances of Lookback Amounts.

Issue 2

Whether the Treasury bill interest rate accrued on the IOUs' unamortized Lookback balances should match the expected term of the amortization period.

Parties' Positions

The IOUs urge BPA to retain the interest rate assumptions Staff proposed in the Initial Proposal for Avista and PacifiCorp. IOU Br., WP-10-B-JP1-01, at 94. The IOUs contend that the long-term interest rates previously established in the WP-07 Supplemental rate proceeding should be retained. *Id*.

BPA Staff's Position

BPA Staff recommended that the interest for each IOU with a Lookback Amount be calculated based on the expected term of repayment. Evans *et al.*, WP-10-E-BPA-40, at 38. Because the expected payoff dates for Avista's and PacifiCorp's Lookback Amount have been extended, a Treasury bill rate commensurate to the new anticipated payoff dates should be used to calculate applicable interest. *Id*.

Evaluation of Positions

In the Initial Proposal, Staff proposes to continue to apply the interest rates determined in the WP-07 Supplemental rate proceeding to Avista's and PacifiCorp's respective Lookback balances. Evans *et al.*, WP-10-FS-BPA-07, at 9-10. Staff proposes these interest rates even though both of these utilities' amortization periods are projected to be extended by an additional three years from the amortization periods assumed in the prior rate case. *Id*. In its direct case, PPC *et al.* take issue with this proposal and argue that BPA should adjust the applicable interest rate to correspond to the expected payback period of the IOU's Lookback Amount. O'Meara *et al.*, WP-10-E-JP8-01, at 13. In rebuttal, Staff agrees with the PPC *et al.* argument and proposes adjusting the interest rates applicable to the unpaid Lookback Amounts of Avista and PacifiCorp to reflect the longer repayment period. Evans *et al.*, WP-10-E-BPA-40, at 38.

The IOUs object to Staff's proposal to revise the interest rates for Avista and PacifiCorp to reflect a longer repayment period. IOU Br., WP-10-B-JP1-01, at 94. Specifically, the IOUs argue that once the long-term interest rates have been established, they should not be increased during the Lookback Amount recovery period based upon a change in the projected length of that period. *Id*.

The IOUs' argument is not persuasive in light of the benefits they receive from the extended payment period. First, BPA never committed to fixing the interest rate applicable to the IOUs' Lookback Amount. Indeed, BPA committed to do quite the opposite. In the WP-07 Supplemental ROD, BPA noted as follows:

> In this Record of Decision, the Administrator adopted a method for recovering and returning the Lookback Amounts that was different than Staff's original proposal. Amongst other differences, the Administrator decided to change the goal of returning the repayment from up to 20 years to seven. To be consistent, BPA will also change the T-Bill rate used to calculate the interest applicable to the IOUs' Lookback Amounts to correspond to the expected term of repayment. This will be an IOU-by-IOU determination. Thus, if an IOU's Lookback Amount will be totally repaid in seven years, the seven-year T-Bill will be used to calculate interest. *If an IOU's Lookback Amount will be repaid in a longer*

> *period, then a T-Bill interest rate matching the longer repayment period will be used*. This approach is consistent with BPA's previous proposal to match the T-Bill interest rate with the expected repayment period.

WP-07 Supplemental ROD (Conformed), WP-07-A-05, at 215 (emphasis added).

As is made clear by the above text, BPA previously determined that the interest rate applicable to an IOU's unpaid Lookback Amount must match the expected repayment period. In the instant case, the amortization periods for Avista and PacifiCorp will likely change as a result of the decisions made in this case. Consistent with the above direction, then, Staff properly recalibrates the interest rates applicable to Avista's and PacifiCorp's Lookback Amounts to reflect these changed repayment periods. The IOUs have offered no arguments that persuade BPA that this decision is incorrect or otherwise unreasonable.

Decision

The Treasury bill interest rate will match the projected amortization period for each IOU with a Lookback balance for FY 2010-2011. Avista's and PacifiCorp's interest rates will be changed to match the term of their expected Lookback amortization period.

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16.0 POWER PROCEDURAL ISSUES

16.1 Introduction

This rate proceeding is developing rates for sales during the last two years of the Subscription contracts. Bliven and Lefler, WP-10-E-BPA-10, at 2. All of BPA's preference customers have signed new, long-term power sales contracts that commence deliveries in FY 2012. *Id*. These new contracts call for a completely new rate design, tiered rates. *Id*. Because of the major changes coming in two years, Staff was directed to confine power rate design changes for the FY 2010-2011 rates to only those that are necessary. *Id*. Therefore, relatively few changes from rates in the current and previous rate periods were embodied in the Initial Proposal. *Id*.

16.2 Issues

Issue 1

Whether the process followed in the BPA-10 rate proceeding has been adequate for parties to provide meaningful input to ratesetting.

Parties' Positions

Snohomish PUD states that the rate proceeding's "procedural flaws" prevented parties from being able to understand and meaningfully review the evidence presented. Snohomish Br., WP-10-B-SN-01, at 16-17. Snohomish states that the "condensed timeframe" made it difficult for parties to understand BPA's approach or contribute constructively to cost allocation and rate design issues. *Id*. at 17. Further, Snohomish continues, the opportunities to seek clarification of BPA's Initial Proposal were not enough to ensure that customers fully grasped BPA's proposals. *Id*.

BPA Staff's Position

The WP-07 Supplemental rate proceeding ended in September 2008, reducing the amount of time Staff normally would have to prepare the 2010 Initial Proposal. Fisher *et al.*, WP-10-E-BPA-36, at 3-4. Relatively few changes from rates in the current and previous rate periods were embodied in the Initial Proposal, however. Bliven and Lefler, WP-10-E-BPA-10, at 2. The Hearing Officer set the rate proceeding schedule after providing opportunity for all parties to comment on BPA's proposed schedule (WP-10-HOO-01). *Id*.

Evaluation of Positions

Snohomish is concerned that the unusually short rate proceeding made it difficult for parties to review and understand BPA's ratesetting approach or contribute constructively to cost allocation and rate design issues. Snohomish Br., WP-10-B-SN-01, at 17. Snohomish also is concerned that the opportunities to seek clarification of BPA's Initial Proposal were not enough to ensure that customers fully grasped BPA's proposals. *Id*. Snohomish points to the "lengthy and often convoluted history" surrounding the development of BPA rates as a contributing factor to Snohomish's difficulty. *Id*. Snohomish states that it has other ideas to improve the rate case

process and requests that the Administrator meet with Snohomish and other customers to discuss ways to improve the overall transparency of BPA's ratemaking process. *Id.*
While BPA is aware that the schedule of the BPA-10 proceeding is somewhat tighter than that of some past rate proceedings, it was not unusually short or compressed. Fisher *et al.*, WP-10-E-BPA-36, at 3. Ideally, BPA would have released the Initial Proposal in November or December 2008, allowing more time in the procedural schedule. *Id.* However, that was not possible in this proceeding, due to the ending date of the WP-07 Supplemental and Tiered Rate Methodology rate proceedings in the fall of 2008 and the Ninth Circuit issuing an opinion in December 2008 that led to restructuring the Initial Proposal. These other proceedings occupied Staff and delayed the start of work on the WP-10 case. *Id.*

This rate proceeding is establishing rates for the last two years of the 10-year Subscription contracts. While the proceeding was slightly delayed, the Initial Proposal did not contain any significant rate design changes, which in theory limited the areas where there would be significant debate due to continuation of the rate design under the prior 8 years of the Subscription contracts. Bliven and Lefler, WP-10-E-BPA-10, at 2. Snohomish was a party to these prior proceedings. In addition, the issues litigated were further limited by reason of the fact that there was an order that preserved issues raised in the WP-07 Supplemental case but also discouraged parties from rearguing those issues in this proceeding. WP-10-HOO-09.

Contrary to Snohomish's statements in testimony, Toulson, WP-10-E-SN-01, at 2-3, BPA conducted rate case workshops preceding the beginning of the 7(i) process. These meetings were noticed, and interested persons could attend in person or by telephone. On October 28, 2008, a three-hour Power Rates workshop discussed general rate case approach, revenue requirement, loads and resources, section 7(b)(2) rate test, the NFB Adjustment, and next steps. The same type of workshop was held on December 3, 2008. At this workshop, attendees discussed a revenue requirement update, a gas price forecast update, REP benefits, risk mitigation and residential exchange, a load forecast update, ratemaking in uncertain times, residential exchange issues, and next steps. A workshop on December 18, 2008, discussed residential exchange issues in the morning and several topics in the afternoon, including generation inputs pricing, market price forecast, net secondary revenues and augmentation, application of CRAC to Exchange, and 7(b)(2) rate test and ASCs. A workshop on wind integration rate development was held the morning of January 23, 2009.

BPA proposed the rate proceeding schedule at the scheduling conference, which was held February 10, 2009, eight days before the prehearing conference. The Hearing Officer issued an Order Establishing Schedule (WP-10-HOO-01) for the WP-10 rate proceeding based on the discussions among the parties at the scheduling conference and the prehearing conference, both of which were noticed and open to all parties. Fisher *et al.*, WP-10-E-BPA-36, at 2-3. During the discussions regarding the development of the schedule, Snohomish did not raise any objection to the timeframes proposed; nor did Snohomish subsequently petition the Hearing Officer for a change in the schedule to allow for additional time.

The schedule set by the Hearing Officer allowed for four full days of clarification of BPA's direct case (Initial Proposal); those four days were not fully used. The schedule also allowed for several rounds of data requests and responses. Snohomish took full advantage of the data request periods by submitting 109 data requests, more than any other party to this proceeding.

The procedural schedule was revised by order of the Hearing Officer multiple times by request of various parties to allow more information to be added to the official record. For example, WP-10-HOO-11 revised the schedule to allow further collaboration among the parties:

> On March 6, 2009, Bonneville Power Administration (BPA) and six other parties … filed a … motion [that] requests a procedural modification to allow for a collaborative process to resolve certain issues related to the current economic uncertainty and BPA's hydro forecast for Fiscal Year 2009. The specific issues are listed in [BPA's motion], and include Market Price Forecast (including BPA's gas price, non-firm and surplus revenue forecasts), Revenue Requirement, Load Forecasts (including need for and level of augmentation) and the use and combination of Risk Mitigation tools, which include the Flexible PF Program, use of agency reserves and Treasury credit facility, the balance between CRAC and PNRR, and the overall TPP level. The motion states that these issues are all related to the overall level of BPA's rates and do not involve the allocation of BPA's rates to specific classes of customers.
>
> … No objections to the motion were received.
>
> The requested procedural modification is designed to accommodate a collaborative effort to resolve the specific issues described above. This process is in the best interest of the parties and the region as a whole, and will not delay the proceeding. The motion is therefore approved.

WP-10-HOO-11. *See, also,* WP-10-HOO-18, WP-10-HOO-26, WP-10-HOO-28, and WP-10-HOO-29. None of those requests came from Snohomish PUD.

No other party has expressed concern about any procedural shortcomings of the BPA-10 rate proceeding related to being able to review, understand, and comment on the issues. In fact, PPC *et al.* point out that during this proceeding "… a great deal of time [was] spent in collaboration between Staff and customer representatives …." PPC *et al.* Br., WP-10-B-JP11-01, at 26. At the same time, BPA strives to be collaborative and to conduct its business in a transparent fashion. In the interval between this rate case and the next, Staff will meet with Snohomish staff to better understand and address Snohomish's concerns and needs. Snohomish states that it appreciates BPA's willingness to meet to discuss its ideas and looks forward to engaging Staff on this important issue. Snohomish Br. Ex., WP-10-R-SN-01, at 2.

Decision

The process followed in the BPA-10 rate proceeding has been adequate for parties to provide meaningful input to ratesetting. BPA welcomes the chance to meet with parties to discuss suggestions for revamping the rate process, especially in light of the upcoming WP-12 rate process, which will set tiered rates for the first time.

Issue 2

Whether BPA should publish preliminary final rates in the Draft ROD.

Parties' Positions

ICNU states that BPA should publish the preliminary rates in its Draft ROD. ICNU Br., WP-10-B-IN-01, at 2, 11-12.

BPA Staff's Position

Staff stated plans to release preliminary rates with the Draft ROD. Lovell *et al.*, WP-10-E-BPA-48, at 2.

Evaluation of Positions

ICNU states that BPA should publish its preliminary final rates in the Draft ROD to provide the parties with a preview of the final rates. ICNU Br., WP-10-B-IN-01, at 2. ICNU states that parties should be provided a thorough understanding of the rates the Administrator is considering to adopt. *Id*. at 11. ICNU states that publishing preliminary rates in the Draft ROD would provide the parties with an opportunity to evaluate the potential rate impact of decisions in the Draft ROD and allow the parties to file better-informed Briefs on Exceptions. *Id*. at 2. ICNU points out that Staff appears to agree with this request. *Id*. at 11.

ICNU is correct. Staff stated that it intends to release preliminary rates with the Draft ROD. Lovell *et al.*, WP-10-E-BPA-48, at 2. Staff clarified that the preliminary rates to be released with the Draft ROD do not comprise a new rate proposal by Staff and will not be supported by documentation like that presented with the Initial Proposal and the Final ROD. The intent is to give parties a preview of rates based on Draft ROD decisions, which may be helpful to parties as they draft their Briefs on Exceptions. However, the intent is not to give parties another opportunity for a formal review. These preliminary rates are presented as a preview of rates pursuant to section 7(i)(5) rates, not a revision of rates pursuant to section 7(i)(4). *Id*. at 2-3. Section 7(i)(5) of the Northwest Power Act describes the Administrator's "final decision establishing a rate or rates based on the record." 16 U.S.C. § 839e(i)(5). Section 7(i)(4), in contrast, describes the Administrator's proposal of "revised rates" and conduct of additional hearings. 16 U.S.C. § 839e(i)(4).

Decision

BPA released a preliminary calculation of final rates based upon the decisions in the Draft ROD at a rate case workshop held on June 29, 2009, shortly after the issuance of the Draft ROD. The preliminary final rates did not comprise a new rate proposal.

Issue 3

Whether the Draft ROD should explain how each of the draft decisions affects the rate increase.

Parties' Positions

ICNU states that the Draft ROD should explain how each of the Administrator's draft decisions on contested issues affects the overall rate increase. ICNU Br., WP-10-B-IN-01, at 11.

BPA Staff's Position

Because this issue arose for the first time in ICNU's Initial Brief, Staff did not address it in testimony.

Evaluation of Positions

ICNU states that the Draft ROD should explain how each of the Administrator's draft decisions on contested issues affects the overall rate increase. ICNU Br., WP-10-B-IN-01, at 11. ICNU states that all parties should be provided a thorough understanding of the rates the Administrator is considering to adopt. *Id*. What ICNU is essentially asking for is a breakdown of each decision and a rate calculation before and after each decision. As discussed in Issue 2 above, BPA provided draft rates reflecting the decisions in the Draft ROD. ICNU wants BPA to go a step further and provide a separate rate calculation for each of the decisions in the Draft ROD. There were a significant number of issues decided in the Draft ROD, which have varying impacts on the rate calculations. ICNU fails to explain how BPA should do what it requests, given the significant number of permutations of decision options possible. Having to explain how each of the Administrator's draft decisions on contested issues affects the overall rate increase (ICNU Br., WP-10-B-IN-01, at 11) would increase the workload and length of the Draft ROD considerably, for an unknown amount of benefit. ICNU does not suggest a baseline for measuring the effect of each decision. Providing rate impacts measured against each party's position on an issue would involve a substantial amount of work.

At the time of publication of the Draft ROD, BPA and parties had completed several rounds of testimony, clarification, data requests and responses, cross examination, Initial Briefs, and oral argument, plus the IPR2 process that discussed the costs on which rates are based. The Draft ROD presents a summary of parties' positions as stated in their briefs, evaluates those positions thoroughly, and provides a draft decision for each issue. At that advanced stage of the proceeding, parties should have a good understanding of the proposed rate design, its effect on rate levels, and the direction and effect (rate increase or decrease) of related issues. This understanding should have a basis in the fact that the current rate design has been in place for several years, and relatively few changes were made for this proceeding. Bliven and Lefler, WP-10-E-BPA-10, at 2.

Decision

BPA did not provide separate rate calculations for each decision in the Draft ROD. As noted in Issue 2, BPA provided preliminary rate calculations based on the decisions in the Draft ROD.

Issue 4

Whether BPA has compiled a record in this case that meets the standards of section 7(i).

Parties' Positions

WPAG states that BPA has not compiled a record in this case that meets the standards of Northwest Power Act section 7(i). WPAG Br., WP-10-B-WG-01, at 3. WPAG claims that virtually the entire process for determining the final level of the PF rate will occur after the testimonial stage of the proceeding has concluded, and thus parties will have no opportunity to "review, critique, or refute any of the forecasts or studies used to set the final level of the PF rate." *Id*. at 4. WPAG furthers its criticism of the rate proceeding by arguing that BPA made a conscious decision not to revise the forecasts and studies, and not to provide the parties a revised PF rate, until after the testimonial stage of this rate proceeding was concluded. WPAG Br. Ex., WP-10-R-WG-01, at 6. WPAG argues that BPA thus deprived the parties to this case of any opportunity to review and respond to these revised forecasts and studies and the resulting PF rate. *Id*.

NRU points out "the deficiency in this section 7(i) process" regarding the information presented at the June 29, 2009, workshop not being presented in the Draft ROD. NRU Br. Ex., WP-10-R-NR-01, at 3, fn. 8.

PPC *et al.* state that a lack of clarity about the final rates at the latter stage of a BPA rate case should not become the norm for future cases. PPC *et al.* Br., WP-10-B-JP11-01, at 26. PPC *et al.* state that the rate case should not become a debate about "construct," which once decided simply produces a rate at the time BPA inputs final numbers. *Id*. In their Brief on Exceptions, PPC *et al.* state that they appreciate BPA's willingness to consider modifications to the rate case process in the future that will give customers a better ability to engage with Staff on the actual rates being proposed. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 12-11.

BPA Staff's Position

Staff noted that the passage of time often presents new or updated information that is different from previous information on the same subjects. Lovell *et al.*, WP-10-E-BPA-48, at 3. This is also often predictably the case between an Initial Proposal and a Final Proposal, given that months can pass between the two proposals. *Id*. Allowing another round of review every time new information is discovered would not lead to the timely conclusion of the rate proceeding. *Id*. at 5. By the time the parties had opportunities to review and comment on the changes to inputs resulting due to new circumstances, the circumstances would undoubtedly have again changed, leading to yet another new set of inputs. *Id*.

Evaluation of Positions

WPAG states that the language of section 7(i) entitles parties to the opportunity to critique and rebut the proposed rates, not merely the policies, methodologies, and assumptions that will be used to compute the proposed rates at some later date. WPAG Br., WP-10-B-WG-01, at 5. WPAG states that this statutory provision requires that the proposed rates be made available for review and comment by the parties to the proceeding. WPAG claims that computing the rates after the testimonial stage of the case is concluded does not satisfy this statutory requirement. *Id*.; WPAG Br. Ex., WP-10-R-WG-01, at 6-7. Rather, WPAG states, it deprives the parties of any meaningful opportunity to participate. WPAG Br., WP-10-B-WG-01, at 5. WPAG adds that by proposing to conduct virtually all of the forecasts and studies, and the computation of the final proposed PF rate, after the testimonial stage is concluded, BPA will deprive the parties to this proceeding of any opportunity to critique the proposed rates. *Id.* at 6; WPAG Br. Ex., WP-10-R-WG-01, at 8. WPAG asserts that this approach is not consistent with the requirements of section 7(i). WPAG Br., WP-10-B-WG-01, at 6. NRU adds, citing the WPAG Initial Brief, WP-10-B-WG-01, at 3-6, that the fact that the material BPA presented at the June 29, 2009, workshop was not presented in the Draft ROD (published six days earlier) "illustrates the deficiency in this section 7(i) process." NRU Br. Ex., WP-10-R-NR-01, at 3, fn. 8.

BPA disagrees with WPAG's and NRU's selective characterization of the BPA-10 rate proceeding. WPAG and all other rate case parties were able to review and comment on the proposed rates, not only the policies, methodologies, and assumptions, included in the Initial Proposal. WPAG and all other rate case parties were able to propose alternative forecasts or methodologies that could be used in establishing final rates. WPAG elected not to provide any alternatives and now complains that it has somehow been deprived of the opportunity to review and comment on those used to establish final rates. It is also not clear why NRU deems the 7(i) process to be deficient due to the fact that information was presented in a noticed workshop rather than in the Draft ROD. BPA conducted the workshop just days after issuing the Draft ROD, in response to numerous requests by rate case parties to see the impact the decisions in the Draft ROD had on various BPA rates. Conducting this workshop was somewhat unprecedented in that BPA does not normally calculate rates with the Draft ROD. Normally rates are calculated at this stage of the proceeding only with the Final ROD. Nevertheless, BPA agreed to calculate preliminary rates and conducted the workshop. The workshop allowed attendees to comment and ask questions in real time to better understand what was behind the rate levels. This workshop did not substitute in any way for the comment allowed in the Briefs on Exceptions, as illustrated by NRU's criticism itself. NRU Br. Ex., WP-10-R-NR-01, at 3, fn. 8.

BPA views the rate proceeding as a presentation of a series of proposed policies, methodologies, and assumptions for performing rate computations. Lovell *et al.*, WP-10-E-BPA-48, at 4. Given the set of inputs in the Initial Proposal, these proposed policies, methodologies, and assumptions yielded the rates contained in the Initial Proposal. *Id.* Some inputs, by their nature *(e.g.*, gas prices), change over the course of time, and the best inputs available at the time will be incorporated into the computations to produce the final rates. *Id.* During the testimonial phase of this proceeding, parties to the rate proceeding had an opportunity to examine and offer refutation on these policies, methodologies, and assumptions, and to offer views on how BPA should compose the final set of inputs into the forecasts and computations. *Id.* These positions become part of the official record on which the Administrator bases his decisions used in setting the final rates. 74 Fed. Reg. 6609 (2009), at 6612; 16 U.S.C. § 839e(i)(5). Ultimately, BPA must finalize the rates using the best information available at that time coupled with the Administrator's decisions on issues raised by parties to and participants in the proceeding on the policies, methodologies, assumptions and legal issues used in the ratesetting process. Lovell *et al.*, WP-10-E-BPA-48, at 4.

WPAG responds to BPA's position by claiming that BPA is merely permitting the parties to discuss proposed policies, methodologies, and assumptions that BPA will use to calculate the final rates at some later date, without ever providing the customers the forecasts, studies, and PF rate. This is incorrect. WPAG recounts forecasts it claims were not provided: the forecasts of natural gas prices, power market prices, secondary revenues, BPA's financial reserves, augmentation amounts and costs, average system costs and Residential Exchange Program costs, financial reserves, and risk premiums such as planned net revenues for risk and cost recovery adjustment clause parameters. WPAG Br. Ex., WP-10-R-WG-01, at 5. The Initial Proposal contained exactly what WPAG accuses BPA of not providing—the forecasts, studies, and PF rate. The load and resource forecasts are published in the Initial Proposal in the Loads and Resources Study and its Documentation, WP-10-E-BPA-01 and -01A. The revenue requirements are published in the Initial Proposal in the Revenue Requirement Study and its Documentation, WP-10-E-BPA-02 and -02A. The natural gas price and power market price forecasts are published in the Initial Proposal in the Market Price Forecast Study and its Documentation, WP-10-E-BPA-03 and -03A. The secondary revenue forecast, BPA's financial reserves, risk premiums, planned net revenues for risk, and cost recovery adjustment clause parameters are published in the Initial Proposal in the Risk Analysis and Mitigation Study and its Documentation, WP-10-E-BPA-04 and -04A. A number of other forecasts, including miscellaneous revenues, augmentation amounts and costs, average system costs, and Residential Exchange Program costs, are published in the Initial Proposal in the Wholesale Power Rate Development Study and its Documentation, WP-10-E-BPA-05 and -05A. Revenues from the provision of generation inputs are published in the Initial Proposal in the Generation Inputs Study and its Documentation, WP-10-E-BPA-08 and -08A. All of these studies comprise the forecasts and studies that WPAG claims were never provided. The PF rate resulting from these forecasts and studies, as well as another showing of the cost recovery clause parameters, are published in the Initial Proposal in the Wholesale Power Rate Schedules, WP-10-E-BPA-07. The computations used to convert the forecasts and studies into the PF rate are explained in the WPRDS, WP-10-E-BPA-05, and documented in the WPRDS Documentation, WP-10-E-BPA-05A.

WPAG is, or should be, aware of all that. The unstated implication of its argument is that BPA had Staff present an Initial Proposal that had no basis in reality simply to satisfy the requirements of section 7(i) and hold in reserve the "real" numbers until after the evidentiary phase was complete. Nothing could be further from the truth. Staff presented the Initial Proposal in good faith, and BPA was prepared to rely on Staff's proposal with minor updates for known changes. As WPAG well knows, during the preparation of the Initial Proposal and in the following months, the U.S. and the worldwide economic landscape were quickly shifting and increasingly uncertain. Parties, in claiming hat BPA must reduce its proposed rate increase, point to this very deterioration as evidence that more must be done to reduce rates.

If WPAG believed that the Initial Proposal was "out of date," it had opportunity to raise such a belief in its direct case. WPAG had opportunity to propose better forecasts and alternatives, but did not do so.

When Staff was faced with the situation of needing to address the effects of the current economic situation on the rate proposal so as to ensure BPA cost recovery, rate case parties, including WPAG, wholeheartedly supported working together rather than having Staff retreat for a period to revise the Initial Proposal. On March 6, 2009, WPAG joined BPA and other rate case parties in filing a motion to amend the schedule to provide for an alternative mechanism for dealing with the concerns over the impact the economic crisis had on the rate proposal. WP-10-M-BPA-02.

The motion explained that during clarification, BPA and the parties discussed using a collaborative process to evaluate this uncertainty and explore the possibility of resolving certain issues. Subsequent to the discussions during clarification, settlement discussions were held on February 26 and 27, 2009. As a result of these settlement discussions, BPA, WPAG, and other rate case parties agreed that some mechanism was needed to allow BPA and the parties more time to work on certain issues prior to the parties filing testimony on these issues. At the same time, parties recognized that there was little or no flexibility in the procedural schedule for BPA to file a supplemental proposal. Rather than having BPA refile aspects of its case, and in order to accommodate the collaborative effort to resolve these specific issues, BPA, along with WPAG, filed a motion to allow parties and BPA to file direct testimony on certain specific issues with their rebuttal testimony. These issues included BPA's market price forecast (including BPA's gas price, non-firm and surplus revenue forecasts), revenue requirement, load forecasts (including need for and level of augmentation), and the use and combination of risk mitigation tools, which include the Flexible PF Program, use of agency reserves and Treasury credit facility, the balance between CRAC and PNRR, and the overall TPP level. The motion concluded with the following statement:

> Without the procedural modification, the Parties will be forced to file their direct cases on these issues without the advantage of working with BPA on alternative solutions that may be in the best interest of the Parties and the region as a whole.

Id. at 2-3. The response to this approach was nearly universal in its acclaim. *See* Issue 1 of section 2.3 above. Even WPAG commended this approach. WPAG stated that BPA management and Staff have dealt remarkably with a tough set of circumstances, finding itself with a rate proposal that was essentially outmoded by events that no one saw coming. Mundorf, Oral Tr. at 222-223. Now, WPAG complains about this procedure, seeking apparently to have it both ways. That is impermissible.

WPAG appears to believe it has the right to continually review not just the policies, methodologies, and assumptions, but every input as it might change through the course of a rate proceeding. Lovell *et al.*, WP-10-E-BPA-48, at 4. At some point, however, the forecasts upon which the rates are based need to be finalized in order to present rates in a timely fashion to the Commission so that the rates can go into effect as planned. *Id.* at 4-5. Parties do have opportunity throughout the rate proceeding to comment, in testimony and briefs, on the policies, methodologies, and assumptions. *Id.* at 5. Some inputs necessarily will change through time due to changing circumstances. *Id.* Allowing another round of review every time new information is discovered would not lead to the timely conclusion of the rate proceeding. *Id.* By the time the parties had opportunities to review and comment on the changes to inputs resulting from new circumstances, the circumstances undoubtedly would have again changed, leading to yet another new set of inputs. *Id.* Operating a rate proceeding in a manner that requires continual review of each set of new inputs is not required by either section 7(i) of the Northwest Power Act or by BPA's implementing procedures. *Id.* Nor is it practical. *Id.* As noted above, section 7(i)(5) of the Northwest Power Act describes the Administrator's "final decision establishing a rate or rates based on the record." 16 U.S.C. § 839e(i)(5). The Administrator develops the record as needed to support and justify his/her decisions and then establishes the rates based on those decisions.

WPAG notes that BPA's rate proceedings guarantee parties certain procedural rights under section 7(i) of the Northwest Power Act, which provides in part:

> One or more hearings shall be conducted as expeditiously as practicable by a hearing officer 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. In any such hearing –
>
> (A) any person shall be provided an adequate opportunity by the hearing officer to offer refutation or rebuttal of any material submitted by any other person or the Administrator[.]

Id., citing 16 U.S.C. § 839e(i)(2).

Consistent with case law, BPA does not apply section 7(i) in such a restrictive fashion that it would result in Staff's initial case being the only outcome that could be used in the final case if any party contests Staff's data or forecasts. Such a holding would conflict with section 7(i)(5), which states:

> The Administrator *shall make a final decision* establishing a rate or rates *based on the record* which shall include the hearing transcript, together with exhibits, and such other materials and information as may have been submitted to, or developed by, the Administrator. The decision shall include a full and complete justification of the final rates pursuant to this section.

16 U.S.C. § 839e(i)(5) (emphasis added). Section 7(i)(5) clearly states that the Administrator is to make his decision "based on the record" of the proceeding. Such record includes the positions of all parties and participants contesting a particular issue. The Administrator is to consider the positions of all parties and participants in reaching his decision. The Draft ROD considered the parties' and participants' positions and provided draft decisions; this Final ROD also provides the "full and complete justification" of the Administrator in reaching his decisions.

The legislative history of the Northwest Power Act, House Interior Committee Report, describes the procedural protections of section 7(i):

> Section 7(i) establishes rather detailed procedures for ratemaking. The Committee amendment clarifies the procedures adopted by the Senate to ensure adequate and effective review of BPA rates and revisions thereof. It is the clear intent of the Committee that no one may use these procedures to frustrate the Act or to delay rate revisions. The BPA must act fairly to ensure full public and customer input, but dilatory tactics must be avoided. Few relish rate changes that result in higher rates, but often they cannot be avoided. The burden is on BPA to justify increases. These procedures should ferret out unjustified or inadequately supported changes.

H.R. Rep. No. 96-976, Pt. I, 96th Cong., 2nd Sess. 69-70 (1980). Here, Congress described the balancing BPA must undertake. BPA must ensure an adequate and effective review while not allowing such review to delay rate revisions. If BPA were required to subject every data or forecast update, whether contested or not, to another round of party/participant review, BPA's rate proceedings could not conclude in a reasonable timeframe.

The fact that the Administrator's final case is different from Staff's initial case does not constitute a new rate proposal for which BPA must provide an opportunity for rebuttal. This principle has been recognized in the context of BPA's rate proceedings. In *Central Lincoln People's Util. Dist. v. Johnson*, 735 F.2d 1101 (9th Cir. 1984), the Court held that BPA's revision of its repayment study, after the original notice and comment, required no new notice and comment:

> PGP argues that section 7(i)(2)(A), which provides parties a right to rebut materials "submitted" to or by BPA, compelled BPA to allow parties the opportunity to rebut the revised repayment study. Section 7(i)(2)(A) ensures that BPA creates a complete administrative record, allowing interested parties to participate in a meaningful way. *This does not mean, however, that each time BPA adjusts the conclusions to be drawn from the record, new notice and comment must begin. Our holding is further supported by the language of section 7(i)(5), which provides no right of rebuttal for materials "developed" by the Administrator, presumably in response to received commentary*. The parties have not indicated the kind of rebuttal they would have made, nor suggested that the revisions were in fact based on any material not already contained in the record. No purpose would be served by requiring yet another round of notice and comment.

Central Lincoln, 735 F.2d at 1118-19 (emphasis added). WPAG's claim that Northwest Power Act section 7(i) requires that the proposed rates be made available for review and comment by the parties to the proceeding is inconsistent with *Central Lincoln*. WPAG's argument would require documentation of BPA's general estimate of the level of a draft rate increase in the evidentiary record, where parties would be afforded the opportunity to respond to it. This argument is not persuasive and is inconsistent with *Central Lincoln*. BPA's final power rate proposal will be based on the Administrator's decisions on the issues identified in the WP-10 proceeding. In developing final rates, the Administrator considers all evidence and arguments made. Any data or assumptions used by BPA in estimating BPA's rates are based on the Administrator's decisions in the Final ROD, which are based on the record. Parties may argue that BPA should use whatever data and assumptions they believe are appropriate in developing BPA's final proposed rates. These arguments are not dependent on knowing what data and assumptions were used in developing BPA's draft rates. The Administrator considers these arguments in developing final proposed rates.

WPAG argues that section 7(i) is violated if parties are precluded from reviewing the information on which the Administrator's decisions have been made and by not providing them adequate notice of the basis of the decision. WPAG states that the notion that providing the parties to a rate case their procedural rights under section 7(i) will result in a rate case without end is wrong and misses the point. WPAG Br. Ex., WP-10-R-WG-01, at 8. WPAG states that it is in the nature of rate cases that the rate proponent puts forth a proposal, the parties offer their analyses and observations, the proposal is altered, and a final round of comment on the revised proposal is provided. *Id*. This is in the nature of rate proceedings, and it is the process that has been followed in prior BPA rate cases. *Id*. That is what the WPAG utilities were expecting, and what section 7(i) requires. *Id*.

But WPAG's argument misses the mark, because parties have been provided the opportunity to address every issue in the rate case. Parties were provided opportunity to put forth a proposal. But nowhere in section 7(i) are parties guaranteed the right to a "final round of comment on the revised proposal" as WPAG claims. Section 7(i)(5) provides that after affording the parties their rights under sections 7(i)(2)-(3), "[t]he Administrator shall make a final decision establishing a rate or rates based on the record which shall include the hearing transcript, together with exhibits, and such other materials and information as may have been submitted to, or developed by, the Administrator." 16 U.S.C. § 839e(i)(5). The Administrator's decisions, as shown in this Final ROD, are based on the rate case record. BPA can adopt a position different from the Initial Proposal based on the record, which may have been provided by any party. As the Court noted in *Central Lincoln*:

> This court has stated that the APA "does not require an agency to publish in advance every precise proposal which it may ultimately adopt as a rule." *California Citizens Band Association v. United States*, 375 F.2d 43, 48 (9th Cir. 1967), *cert denied*, 389 U.S. 844 … (1967). The main concern is to ensure that the final rule is sufficiently related to the proposed rule that the challenging party had notice of the agency's contemplated action. [citations omitted].

Central Lincoln, 735 F.2d at 1118.

All parties have had notice of all studies, documentation, and testimony filed in this proceeding, including notice of what inputs may be updated. Adequate notice of the Administrator's decisions in the Final ROD has not been an issue. Section 7(i) requires that "any person shall be provided an adequate opportunity by the hearing officer to offer refutation or rebuttal of any material submitted by any other person or the Administrator." 16 U.S.C. § 839e(i)(2)(A). The Final ROD does not constitute material presented as evidence before the Hearing Officer. The Final ROD is a decision document, not a piece of testimony. Furthermore, the parties have had a full and complete opportunity to refute or rebut any and all material presented by BPA in the evidentiary hearing and have taken advantage of that opportunity. The Final ROD documents the record evidence upon which the Administrator's decisions are based. Parties had the opportunity to respond to the Administrator's draft decisions in their Briefs on Exceptions.

Section 7(i) also provides that "the Administrator shall make a final decision establishing a rate or rates based on the record…." 16 U.S.C. § 839e(i)(5). The Administrator's final decisions are based on the record.

WPAG argues that, by electing to wait until after the testimonial stage of this proceeding was concluded to perform revisions, BPA has deprived the parties to this case of any opportunity to review and respond to these revised forecasts and studies, and the resulting PF rate. WPAG Br. Ex., WP-10-R-WG-01, at 6. WPAG cites to the revised forecasts and studies, and a revised PF rate, performed by BPA to prepare the handout provided to parties at the June 29, 2009, rate case meeting as evidence of BPA's decision. *Id.*

WPAG ignores that the revised forecasts, studies, and PF rate were provided *as a courtesy* to parties on June 29, 2009 to help them prepare Briefs on Exceptions. Thdse were not provided as a matter of procedural right. Consequently, WPAG has no basis to argue procedural error, when BPA in fact provided more process than statutorily required.

PPC *et al.* state that a lack of clarity about the final rates in the latter stages of a BPA rate case should not become the norm for future cases. PPC *et al.* Br., WP-10-B-JP11-01, at 26. PPC *et al.* continue:

> … [I]t is problematic for BPA's rate proceedings to become a debate about a "construct," which, once decided, simply produces a rate at the time BPA inputs final numbers. Such a result appears to be far from the process described in the Northwest Power Act, which guarantees parties the right to comment on and rebut BPA's proposals on "rates"—not just "constructs." PPC of course understands that BPA is experiencing uncertainties, due to difficult and unpredictable economic circumstances, and PPC has no complaints about the level of cooperation by BPA staff in this case. However, PPC believes that more (or at least something different) should be done in future cases to give customers and rate case participants a clear understanding of the actual rates that are being proposed. This may involve a re-working of the rate case procedures, and PPC looks forward to working on that process, which has been discussed in past proceedings as well. Doing so may be especially important given that rate cases under the Tiered Rate Methodology may demand a different approach to rate setting than has been used in the past.

Id. PPC *et al.* raise no specific procedural concern with the current case.

The issues and concerns raised by PPC *et al.* give BPA pause whether it can improve its rate case and customers' satisfaction, so BPA will endeavor to work with rate case parties to explore and develop procedures for rates determined pursuant to the Tiered Rate Methodology. In their Brief on Exceptions, PPC *et al.* commend BPA for its willingness, as stated in the Draft ROD, to consider modifications to the rate case process that will give customers a better ability in the future to engage with Staff on the rates being proposed. PPC *et al.* Br. Ex., WP-10-R-JP12-01, at 11. PPC *et al.* admit that they have no "concrete fixes" at this point, but they state that they are confident that parties can develop improvements that will make the process better. *Id*. BPA looks forward to this collaborative process.

Decision

The record in this case does meet the standards of section 7(i). BPA is not required to allow parties to review, critique, or refute any of the forecasts or studies used to set the final rates.

Issue 5

Whether BPA should reconsider each issue reserved from the WP-07 Supplemental Proceeding and revise its determinations in this case consistent with the consolidated evidence and argument.

Parties' Positions

APAC argues that BPA should reconsider each of the reserved issues from the WP-07 Supplemental proceeding and revise its determinations consistent with the consolidated evidence and argument in this case. APAC Br. Ex., WP-10-R-AP-01, at 3.

BPA Staff's Position

This issue was raised for the first time in APAC's Brief on Exceptions. BPA Staff has no stated position on this issue.

Evaluation of Positions

APAC argues that BPA should reconsider each issue reserved from the WP-07 Supplemental Proceeding and revise its determinations consistent with the consolidated evidence and argument in this case. APAC Br. Ex., WP-10-R-AP-01, at 3 (footnotes omitted).

The Administrator has reviewed the existing record of the issues raised in the WP-07 Supplemental Proceeding and any additional evidence or argument presented in the WP-10 Rate Proceeding on such issues in making the determinations contained in this Final ROD. If review of the existing record in conjunction with any new evidence or argument has changed the Administrator's position on any issue, such is indicated in this ROD.

Decision

BPA reviewed and, if necessary, revised determinations in this case consistent with the consolidated evidence and argument.

Issue 6

Whether BPA should review the Citizens' Utility Board's (CUB) arguments that BPA rejected.

Parties' Positions

In its Brief on Exceptions, CUB renewed the arguments made in its Initial Brief that were rejected by BPA. CUB Br. Ex., WP-10-R-CU-01, at 1.

BPA Staff's Position

This issue was raised for the first time in CUB's Brief on Exceptions. BPA Staff has no stated position on this issue.

Evaluation of Positions

In CUB's Initial Brief, it raised a number of issues related to the Lookback payments that CUB had previously raised in the WP-07 Supplemental proceeding. BPA moved to strike the CUB Initial Brief based upon the fact that these issues from the WP-07 Supplemental Proceeding were preserved and need not be raised again in this case. WP-10-M-BPA-13. BPA's motion was granted for the most part, and a large portion of CUB's brief was stricken. WP-10-HOO-09.

(The only remaining portion was the introduction, which addressed some general concerns about rate levels. This issue is addressed in section 2.3 of the ROD.)

CUB's Brief on Exceptions consists of the following sentence only: "CUB renews the arguments made in its Initial Brief that were rejected by BPA." CUB Br. Ex., WP-10-R-CU-01, at 1.

Based on the statement in CUB's Brief on Exceptions, BPA is uncertain what arguments CUB would have BPA reconsider. It is not clear whether CUB's request is aimed at the single issue that remained after the motion to strike was granted or whether CUB's Brief on Exceptions is an attempt to reargue the stricken portions of its Initial Brief. The confusion arises from CUB's use of the phrase "rejected by BPA" to qualify the arguments it wishes to renew. It is not clear whether this phrase relates to the arguments addressed in the Draft ROD or those arguments stricken by the Hearing Officer (it was the Hearing Officer, not BPA, who granted the motion to strike.)

In the Draft ROD, BPA addresses CUB's concern that the current recession creates huge economic challenges for utility consumers. CUB Br., WP-10-B-CU-01, at 2. CUB hopes that BPA would find a way to moderate the increase in rates in light of the state of the economy. *Id.* at 3. BPA states in the Draft ROD that it would set rates to recover its cost, but notes that it would make every effort to keep the level of the rates down. Draft ROD at 6-7. To the extent CUB's Brief on Exceptions seeks to have BPA reevaluate the rate level, BPA stands by the determination in section 2.3 of this ROD. Rate levels must be set to recover costs. That said, BPA recognizes the impact its rates may have on the economy and has taken significant steps to keep rate levels as low as possible (*see* section 2.3).

To the extent that CUB is using its Brief on Exceptions to renew arguments previously stricken by the Hearing Officer, those stricken arguments are not currently before the Administrator for a decision. As explained in greater detail in section 1.1.5, for efficiency and economy for all concerned, parties do not have to reargue matters previously raised and addressed in the WP-07 Supplemental proceeding. Furthermore, given that CUB's arguments are preserved for appeal pursuant to WP-10-HOO-09, CUB is not prejudiced by the Hearing Officer's decision to strike those sections of its Initial Brief. From the record, it is clear that CUB merely copied the arguments from its WP-07 Supplemental brief, making minor changes to the various sections to account for the fact that these were different rate cases, and resubmitted the material in this proceeding. As noted, these issues were previously addressed in the Administrator's WP-07 Supplemental Final Record of Decision. This is precisely the type of action that BPA and the other rate case parties were attempting to avoid when the motion underlying the Hearing Officer's preservation order was made.

Decision

To the extent CUB is seeking to have BPA review its decision on the appropriate rate level, that matter is addressed in section 2 of this ROD, and BPA stands by its decision in the Draft ROD. To the extent CUB is seeking to have BPA review issues that were stricken from CUB's Initial Brief, BPA will not review those matters in this ROD. All of those issues were addressed in the Administrator's WP-07 Supplemental Final Record of Decision, and pursuant to the Hearing Officer's order, WP-10-HOO-09, are preserved to raise on appeal.

Issue 7

Whether excluding from the rate case issues related to program cost levels is inconsistent with section 7(i) of the Northwest Power Act and the Ninth Circuit decision in Golden Northwest Aluminum v. BPA.

Parties' Positions

WPAG raises for the first time in its Brief on Exceptions the contention that excluding from the rate case discussion of certain subjects related to the revenue requirement is inconsistent with the procedural rights granted under section 7(i) of the Northwest Power Act and is a position that has been rejected by the Ninth Circuit in *Golden Northwest Aluminum v. BPA*, 501 F.3d 1031, 1051, 1053 (9th Cir. 2007). WPAG Br. Ex., WP-10-R-WG-01, at 10.

BPA Staff's Position

This issue was raised for the first time on Brief on Exceptions. BPA Staff has no stated position on this issue.

Evaluation of Positions

The only issues related to the revenue requirement that were excluded from the rate case in the Federal Register Notice involved limited argument regarding program level expenses. 74 Fed. Reg. 6609 (2009), section V.A.1.

> BPA's spending levels for generation investments and power expenses are not determined or subject to review in rate proceedings. Pursuant to § 1010.3(f) of BPA's Procedures, the Administrator directs the Hearing Officer to exclude from the record all argument, testimony, or other evidence that challenges the appropriateness or reasonableness of the Administrator's decisions on power spending levels. If, and to the extent that, any re-examination of spending levels is necessary, that re-examination will occur outside the rate proceeding.

Id.

The issue regarding litigating program level costs in the rate case is one that was vigorously contested during the rate cases during the early to mid-1990s, and addressed thoroughly in the Administrator's Records of Decision. BPA incorporates that analysis herein as if fully set forth, but provides this summary response for purposes of briefly explaining BPA's position. Over the past few rate cases the issue has not been raised in briefs or addressed specifically in the various RODs. Nevertheless, WPAG in its Brief on Exceptions revives, although in a very conclusory fashion, arguments it made in rate cases during the 1990s that were rejected by the Administrator. *See* WP-93-A-02 at 319-340. In this latest version of the argument, WPAG adds a new element, contending that the exclusion of discussions over program level expenses is not only inconsistent with section 7(i), but is also contrary to the Ninth Circuit's decision in *Golden NW*.

With the passage of the Transmission System Act in 1974, BPA became self-financing and no longer subject to annual congressional appropriations. 16 U.S.C. § 838i(a). While the

Transmission System Act freed BPA from seeking annual appropriations, it expressly provided for congressional review of BPA's budgets. Pursuant to the Transmission System Act and Government Corporation Control Act, BPA prepares an annual budget for submission to the President. Each budget contains proposed expenditures for the upcoming budget year and the following four budget years. 31 U.S.C. § 1105(a)(5).

After the President submits the budget to Congress, Congress is authorized and required to adopt a budget that "set[s] forth appropriate levels for the fiscal year beginning on October 1." 2 U.S.C. § 632(a). Unless the President reduces BPA's proposed spending levels or Congress limits BPA's spending authority in an annual appropriations act, BPA is authorized to expend the money in the Bonneville fund. The Federal budget process, not the rate case, is the forum for determining BPA's spending levels. Any attempt to compel BPA to reduce its program levels through litigation is an attempt to usurp the authority granted to BPA by the Transmission System Act and intrudes on Congress's prerogative to determine BPA's spending levels. The parties would subject BPA's authority to the outcome of the rate case, adding a criterion not contemplated by the Transmission System Act or any other statute. BPA's spending levels are included in the Federal Budget, and litigation of these spending levels in the rate case would usurp the President's and Congress's role in overseeing BPA's budget.

If BPA's spending level decisions were subject to review in the rate case, it would also mean the budgets are subject to program-level judicial review at the Ninth Circuit, in contravention of the constitutional doctrine of separation of powers. The object of separation of powers is "to preclude a commingling of the essentially different powers of government in the same hands." *O'Donoghue v. U.S.*, 289 U.S. 516, 530 (1932). If BPA program-level expenses were subject to Ninth Circuit review, the Administrator would have to justify congressionally approved budgets in the rate case. This result is wholly inconsistent with the constitutional doctrine of separation of powers.

Section 7(i) of the Northwest Power Act governs the procedural aspects of BPA's rate cases. Nothing in the Northwest Power Act grants parties the right to challenge Federal budget decisions. WPAG's argument would seem to suggest that its right under section 7(i) to comment on issues in the case includes the right to contest program and spending levels and that the "full and complete" record of the hearing and justification of the final rates required by section 7(i) must also encompass spending levels. However, this argument would beg the question. Section 7(a) provides that the Administrator must set rates to recover BPA's costs, but it says nothing regarding how those costs are established. Furthermore, while section 7(i) establishes the procedural protections for a rate case, it does not establish the substantive legal basis for establishing BPA's budgets. Those, as previously noted, are established pursuant to the Transmission System Act and Government Corporation Act and not under section 7 of the Northwest Power Act.

WPAG's interpretation of *Golden NW* is inconsistent with the Court's opinion in that case. The Court did not, as WPAG suggests, reject the exclusion of program level costs from the rate case. Instead, *Golden NW* addressed the question of BPA's weighting of the 13 fish and wildlife alternatives.

In forums external to and in advance of the WP-02 rate proceeding, BPA had developed 13 alternatives (with associated estimated costs) for carrying out its fish and wildlife obligations. BPA did not alter the alternatives or the equal weighting of them in risk analyses in any significant way over the three years from the time of the development of those alternatives to publication of the Final Supplemental ROD in 2001. Tribal parties to that case asserted that additional information suggested that BPA was significantly underestimating its fish and wildlife costs. While the Court did express a belief that the fish and wildlife projections were too low, *Golden NW*, 501 F.3d at 1052, the Court's actual holding was that BPA's failure to reassess its fish and wildlife costs in light of the evidence meant the agency was arbitrary and capricious. It was not, as WPAG contends, a blanket determination that program level expenses are now part of the rate case. Instead, the Court focused on process concerns—that the adherence to outdated information, *id*. at 1051, and discounting or ignoring crucial facts presented to BPA, *id*. at 1053, were inappropriate. Contrary to the implications of WPAG's argument in the instant case, the Court specifically stated that "we understand that the WP-02 rate case is not the forum for making decisions regarding which fish and wildlife alternative to implement…." *Id*. In so stating, the Court recognized that these and other programmatic decisions would be made outside the rate case, but that BPA's adherence to those decisions made outside the rate case must consider the information available at the time the final decision is made.

In the present case, BPA re-reviewed its program-level assumptions in a public forum (IPR2) just weeks before the issuance of this ROD. As such, the assumptions in the rate case, unlike the circumstances giving rise to the matter in *Golden NW*, reflect the best available information at this time.

Decision

The decision to exclude from the rate case issues related to program cost levels is not inconsistent with section 7(i) of the Northwest Power Act or the Ninth Circuit decision in Golden Northwest Aluminum v. BPA.

17.0 POWER PARTICIPANT COMMENTS

17.1 Introduction

This chapter summarizes and evaluates the comments of participants in BPA's WP-10 rate proceeding. "Participants" are persons and organizations that comment on BPA's rate proposal but do not take part in the formal rate case hearings with the responsibilities of "parties." Parties to the proceeding cannot submit comments as participants; parties can use testimony and briefs to be heard in this proceeding. Comments of participants are part of the official record of the rate proceeding and are considered when the Administrator makes his decisions for the rate proceeding, as set forth in the Administrator's Final Record of Decision.

The participant comment period for this proceeding began when BPA published the Federal Register Notice. 74 Fed. Reg. 6609 (February 10, 2009). The February 10 Federal Register Notice may be viewed at
http://www.bpa.gov/corporate/ratecase/2008/2010_BPA_Rate_Case/docs/FY10-11_FRN.pdf.

BPA published a second Federal Register Notice related to the WP-10 proceeding, which clarified the definition of "participant" included in the notice published on February 10. 74 Fed. Reg. 9090 (March 2, 2009). Specifically, the following sentence was substituted for a sentence previously included: "Any entity that has intervened in this proceeding may not submit participant comments." The March 2 Federal Register Notice may be viewed at
http://www.bpa.gov/corporate/ratecase/2008/2010_BPA_Rate_Case/docs/FY10-11_FRN_Correction.pdf.

Three utilities that individually intervened in this proceeding as part of larger utility groups also submitted comments as participants: Skamania PUD (BRCO90001), represented by WPAG and NRU; Grays Harbor PUD (BRCO90263), represented by WPAG; and Oregon Trail Electric Consumers Cooperative (BRCO90291), represented by NRU. As stated in the Federal Register Notice (Correction), "Any entity that has intervened in this proceeding may not submit participant comments." 74 Fed. Reg. 9090 (March 2, 2009). Because the utilities listed above are parties to the rate case, they may not also be participants. The comments cited above will not be addressed in the Record of Decision. Skamania PUD raised questions about reliance on the Treasury note. This topic is generally addressed in Chapter 7 (Risk). Grays Harbor's comments are generally addressed in Chapters 2, 7, and 12 (Policy, Risk, and DSI). Oregon Trail's comments are generally addressed in Chapters 2, 7, 12, and 14 (Policy, Risk, DSI, and Rate Design).

Both of the Federal Register notices mentioned above set the close of participant comment date as April 24, 2009. At BPA's request, the Hearing Officer extended the period for participant comment to May 15, 2009. WP-10-HOO-28; TR-10-HOO-17. The participants' portion of the official record consists of 400 comments received by the close of comment date. Most of the comments were from retail consumers of publicly owned utilities in the Pacific Northwest (BPA customers). All of the comments may be viewed at
http://www.bpa.gov/applications/publiccomments/CommentList.aspx?ID=61.

At least two consumer-owned utilities notified their customers about BPA's proposed power rate increase and encouraged them to send comments to BPA. Thus, BPA received a large number of comments from ratepayers of those two utilities. Most referenced the information provided them by their utility. Many used the utility's words in their comments; others told of their own particular circumstances and asked BPA to consider their situations before raising rates. One enterprising ratepayer circulated petitions and submitted over 250 signatures, all in opposition to the Initial Proposal rate increase.

BPA has reviewed the participants' portion of the record and identified the concerns expressed by the participants to be addressed in this chapter of the Record of Decision. The tallies of the participants' comments that appear below combine similar concerns for ease of summarizing. Summaries of the concerns expressed by participants, and discussions of these concerns, are provided below.

17.2 Evaluation of Participant Comments

Topic: Managing the Rate Increase	Number of Comments
Eliminate the rate increase.	341
Minimize the rate increase.	18
Postpone the rate increase until the economy is better. The region cannot afford a rate increase. Higher rates would harm the economy further.	107
The rate increase is unjustified. Hydro and wind generation use cheap fuels. There is no reason to raise rates when BPA has monetary reserves.	38
Rates should be decreased, not increased.	4
No rate increase for public utility/preference customers.	4
Higher rates would harm small businesses and farms.	25
Higher rates would hurt people. People cannot afford a rate increase. The consumers have made BPA what it is. Do not harm them. Federal agencies should serve the people and stimulate the economy. BPA will lose revenue when people cannot afford to pay for power. BPA's mission is to provide power. Residential customers should be BPA's priority.	165
The rate increase is illegal, and you will regret it.	1
Can you use economic stimulus funds to reduce the rate increase?	1
Raising rates would reduce money available for renewable resources.	4

The overwhelming majority of participant comments opposed the level of rate increase in BPA's Initial Proposal. Most cited the economic recession gripping their locale, the Pacific Northwest region, the U.S., and the world and stated that this is an inappropriate time to raise rates at all, let alone by the amount BPA initially proposed. Many described their own financial circumstances as dire and in need of assistance and stated that a rate increase would harm them, their family, and others in their community, especially those on fixed incomes or who had lost jobs and had no income. Participants stated that a rate increase would be harmful to small businesses and rural areas, in particular. Several participants stated the belief that if BPA raises rates, consumers will cut back demand, resulting in less revenue for BPA.

Many participants pointed out that the Federal Government has been trying to stimulate the economy and stated that it is wrong for BPA, a Federal agency, to raise power rates because it could make the recession worse. Several participants stated that BPA should return to the role for which it was created, providing low-cost power to the region and thus serving the people of the Northwest. Several stated that publicly owned utilities (also called preference utilities) should receive no rate increase. Participants stated that the ratepayers had made BPA what it is and that BPA should consider them before raising rates.

Response: BPA understands that in these difficult economic times, any rate increase could be looked upon as a hardship by many people. That is why, as explained throughout this document, BPA has worked with its customers and the interested public before and during the formal rate proceeding to reduce the level of any needed power rate increase. At the same time, however, BPA has statutory requirements that must be met when setting its rates, as explained in Chapter 1 of this document. BPA receives no appropriations from Congress to pay its expenses. Rather, BPA is a self-financing agency and must establish its rates to recover its costs. In addition, BPA has a longstanding goal of making its debt payments to the U.S. Treasury on full and on time, which maintains BPA's good credit rating and keeps debt costs lower in the long run. BPA recovers its costs primarily through the wholesale power and transmission products it sells to utilities. In turn, the cost of purchasing BPA power and transmission services is a cost BPA's utility customers must recover from their retail consumers. The cost of BPA power makes up a significant part of the costs utilities recover from their retail consumers; how much of the BPA rate increase any particular utility passes along to its consumers ultimately depends on decisions made by the local utility's management.

BPA has multiple responsibilities, including, but not limited to, encouraging conservation and energy efficiency, developing renewable resources within the region, protecting fish and wildlife affected by the development of the Federal Columbia River Power System, and ensuring the region an adequate, efficient, economical, and reliable power supply. The Northwest Power Act encourages "participation and consultation" in developing plans and programs for resources and fish and wildlife, facilitating orderly planning of the region's power system, and providing environmental quality.

The Northwest Power Act confirms guidance from earlier statutes that "the customers of the Bonneville Power Administration and their consumers continue to pay all costs necessary to produce, transmit, and conserve resources … including the amortization on a current basis of the Federal investment in the Federal Columbia River Power System." BPA's challenge is to strike a balance between fulfilling its multiple responsibilities and keeping rates as low as possible consistent with sound business principles.

Regarding the use of economic stimulus funds, BPA already has received additional borrowing authority under the American Reinvestment and Recovery Act. Money received under the American Reinvestment and Recovery Act is for borrowing purposes, however, and will not help reduce rates. BPA has also expanded its access to short-term liquidity through an agreement with the Department of the Treasury. BPA's short-term liquidity is being relied upon in this rate case to provide risk mitigation, as discussed in Chapter 7. The availability of the additional liquidity has allowed BPA to lower the rate increase significantly.

Topic: Costs	Number of Comments
Cut BPA internal and operations costs (executive salaries were mentioned frequently). Find ways to be more efficient. Defer construction. Hold executives accountable. Accept lower profits. Look at all your options. Do top-down budgeting rather than bottom-up.	116
Don't make ratepayers pay for BPA's inefficiencies or mistakes. The rate increase is an example of corporate greed. We need good leaders who will protect citizens.	15
Don't integrate expensive power into the BPA system.	2
Reconsider CGS (Columbia Generation Station).	1
Install natural gas generation to reduce costs.	1
Use nuclear power to reduce costs.	3
Do not raise rates to support wind. Don't raise rates for so-called green power. If Oregon doesn't get the benefit of wind turbines in Oregon, remove them.	3
Focus on grid interconnections and reliability rather than lowest cost.	1
Support fish programs.	2
Don't subsidize private utilities (investor-owned utilities or IOUs) with money from public utilities. This is illegal.	286
Don't subsidize aluminum companies. This is illegal and wrong while individuals are struggling.	312
Don't support fish recovery projects more than the law requires. Don't raise rates to help salmon. Curb spending for environmental projects.	263

Some participants suggested that BPA's proposed rate increase is unjustified and based on corporate greed and that BPA should reduce its profit before hurting ratepayers. Many of the comments included suggestions for reducing the proposed rate increase, such as cutting BPA's internal costs and operating costs, finding efficiencies, improving processes, freezing BPA employees' salaries, laying off executives, and cutting BPA executives' salaries and bonuses. Some participants stated that because energy prices are down and demand must be down because of the recession, BPA's rates should be decreasing, not increasing. Participants stated that BPA should live within its means, as they do, and tighten its belt, as they have had to do.

Several participants suggested that BPA should lead the way with good management and wise decisions that would put the citizens of the region first. One comment stated that economic consultants and efficiency experts can help BPA cut costs.

Many participants addressed the legality of the rate increase, stating that BPA should not "subsidize" investor-owned utilities through the Residential Exchange Program or aluminum companies through special rates. Many also stated that BPA is supporting salmon recovery projects more than is required by law. One stated that BPA should put people ahead of fish. One comment stated that BPA should adopt the Alcoa rate proposal to retain family-wage jobs. Other participants argued against supporting Alcoa or, generally, aluminum companies.

Response: In general, the topic of costs is outside the scope of the rate case, because BPA sets costs in the Integrated Program Review (IPR) public process. The IPR process is designed to provide the public the opportunity to learn about and comment on what costs BPA's power rates will cover. IPR allows the public to provide input into program funding levels prior to the ratesetting process. The goal is to help ensure that BPA's expenses are set as low as possible while maintaining BPA's ability to carry out its mission. Because of the rate case participants' strong negative reaction to the level of the initially proposed rate increase, however, and the concurrent nature of the FY 2010 rate case and the IPR2 process, this chapter of the Record of Decision will address the participants' rate case comments on costs. For further information, refer to the IPR2 Final Report and Chapter 5.

As noted in other chapters of this Record of Decision, cost increases are the primary driver of the proposed rate increase for fiscal years 2010 and 2011. Many of BPA's costs arise from BPA being subject to provisions of law, in particular the Northwest Power Act of 1980. For example, section 5(c) of that law directs BPA to conduct the Residential Exchange Program (REP), which can reduce the retail rates of residential and small farm consumers served by IOUs. The Northwest Power Act also tells BPA how to allocate the costs of the REP among the wholesale power customers BPA serves. That law also allows BPA to sell power to aluminum companies and other direct-service industrial customers (DSIs). At the same time, however, the Northwest Power Act (section 5) is clear that "all power sales under this Act shall be subject at all times to the preference and priority provisions of the Bonneville Project Act of 1937 … ." The Northwest Power Act (section 7) also provides that BPA's rates shall be based on BPA's costs. BPA's ratesetting is a balancing act that must keep all those legal provisions in mind. Section 1.2 of this Record of Decision discusses the laws that govern how BPA sets its rates.

BPA is a Federal agency and as such is a not-for-profit entity. Participants who mentioned that BPA should reduce its profits to keep rates low may not realize that BPA is a not-for-profit entity. The major use of financial reserves is for risk mitigation, as discussed in the rate case (Chapter 7 of this Record of Decision). Just as a household is wise to have a savings account for emergencies, BPA keeps financial reserves "in the bank" to make sure BPA can pay its bills even if revenues are not enough to cover its costs. The different kinds of risk BPA faces, and the risk mitigation measures BPA uses, are described in BPA's direct testimony in this rate case, WP-10-E-BPA-14. One participant commented that BPA appears to be taking on a lot of risk, "leveraging" itself, and suggested that BPA define a trigger in terms of declines in financial reserves for initiating another 7(i) process to recalculate rates. BPA has a mechanism in place that responds to declines in financial reserves, the Cost Recovery Adjustment Clause. The Administrator retains the discretion to initiate another 7(i) process; no explicit trigger is needed for this authority. One participant suggested that BPA assume the Flexible Priority Firm Power rate is used as a liquidity tool. This issue is addressed in ROD Chapter 7, section 7.6. Some comments raised concerns regarding the pay level of BPA employees and whether reducing or freezing pay levels could help keep rates low. BPA's employees, including managers all the way up the pay scale to the Administrator, are Federal employees. Thus, BPA's pay for its employees is based on Federal government regulations, and the pay scale is established by Congress. As noted in the IPR2 process, though, which set the cost levels for the final rate proposal, BPA has the ability to reduce some of its internal costs, including employee bonuses. The IPR2 report states that BPA has reduced its internal operations costs for the rate period by $17.8 million since the initial rate proposal. As noted in the IPR2 Final Report, internal costs were reduced in that process specifically to minimize the needed increase in power rates.

Many participants stated that BPA should not be "subsidizing" investor-owned utilities. As noted above, BPA is required by the Northwest Power Act to conduct the Residential Exchange Program. As defined by law, however, the REP is not a subsidy for the IOUs and does not benefit the corporate utilities; instead, it reduces the retail rates of certain consumers of those IOUs that take part in the REP. By law, the investor-owned corporate entities cannot benefit from the REP. The rates of BPA's preference utility customers include part of the net cost (costs minus revenues) of the REP. (The costs of BPA power generally make up about half of a public utility's costs.) The end result is a sharing of BPA's lowest-cost resources between the consumers that buy power from preference utilities and the residential and small farm consumers of certain IOUs. Both should be viewed as ratepayers of BPA.

How BPA sets its rates for power it sells to direct-service industrial customers, such as aluminum smelters, also is based on the Northwest Power Act (section 7(c)). Section 7(c)(1)(B) states that the DSI rate must be based "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." Sections 7(c)(2) and 7(c)(3) describe the steps BPA must follow to ensure that the DSI rate is "equitable." BPA implements congressional direction in determining DSI rates. The direction under Federal law causes costs to be moved from the DSIs to the preference utility and exchanging customers; BPA has followed this method since the year 1985. This process is discussed in Chapter 12 of this Record of Decision. One participant asked how BPA is planning to mitigate the risk of losing litigation over possible service to DSIs if one or more of the DSIs is in bankruptcy at that time. BPA does not model legal risks; BPA plans to respond to the outcome of litigation with means available after the litigation is concluded.

Participants are concerned that they are paying a "subsidy" to the aluminum companies at all, and especially in a time of economic recession. We are sympathetic to the participants' concerns, as we are sympathetic to the concerns of employees of the two remaining aluminum companies in the region. BPA currently has no signed contract with either aluminum smelter and thus must set rates by assuming what will happen and what the risks are of those assumptions. BPA has not yet made a decision as to whether and how it will serve the DSIs in the upcoming rate period, though. That decision will be made after the FY 2010 rate proceeding, in a separate public process. See Chapter 12 of this Record of Decision for more information.

Many participants noted that one of the major drivers of BPA's initially proposed rate increase was the cost of fish programs due to new biological opinion requirements and implementation of the Columbia Basin Fish Accords. Those increased costs were subject to discussion in the IPR and IPR2 processes. The biological opinion was developed by NOAA Fisheries to address Endangered Species Act requirements for the Federal Columbia River Power System. The new biological opinion was ordered by a Federal court following the court's rejection and remand of the prior biological opinion in response to a lawsuit. The Fish Accords were negotiated by BPA, the U.S. Army Corps of Engineers, the U.S. Bureau of Reclamation, and state and tribal governments. Collectively, the goal of the new biological opinion and the Fish Accords was to identify and implement actions for helping threatened and endangered salmon and steelhead in the Columbia Basin. We recognize that BPA ratepayers will bear most of the costs of these actions for fish. By operation of a variety of Federal laws, those who purchase power from BPA have a responsibility to pay for protecting fish and wildlife in the Columbia River basin affected by the Federal Columbia River Power System. In the IPR2 process, spending for fish protection and recovery was decreased by $15 million for 2010 due to some projects having a slow start. That reduction in fiscal year 2010 will help reduce the proposed rate increase, although that spending is deferred to a future year, not eliminated.

A few participants had comments about specific cost items and resource types (see the Costs summary table above). One participant urged BPA to focus on grid interconnections and reliability rather than "lowest cost power." Another participant stated that BPA should install natural gas plants to take advantage of low natural gas prices, meet peak demands, and counter other rising costs. Several participants wondered why BPA would need to raise rates, since the dams are already installed and the fuel is free. Similarly, several participants stated that with the growth in the amount of wind generation in the Northwest, with its free fuel, BPA's costs should be decreasing. Several participants stated that BPA should avoid adding high-cost resources to the system to avoid their costs going into rates. Several participants stated that nuclear power should be used for efficiency, lower costs, and environmental benefit.

These individual cost and resource comments are outside the scope of the rate case. Costs are discussed and set in the Integrated Program Review. Long-term resource strategy is discussed and set in the Resource Program, which is currently underway. BPA does not own or construct generating resources. BPA decides whether to acquire the output of generating resources based on many factors, of which cost is an important one. Fuel is one cost of operating a resource, but there are many more, including permits, maintenance, repair, and transmission of the output.

Topic: Rate Design	**Number of Comments**
BPA should have more incentives for people to have their own power systems.	2
You may raise rates, but first increase minimum use by 50 percent for residential.	1
We have economized and conserved. Penalize those who waste energy.	3

Topic: Rate Design	Number of Comments
The Alcoa rate proposal should be adopted to keep family-wage jobs.	1
Opposes Alcoa variable rate.	1
Strengthen risk mitigation package; reconsider forward-looking Cost Recovery Adjustment Clause.	1

Several participants mentioned the level of reserves: one stated that there is no reason for BPA to raise rates while it holds such a high level of reserves; one stated that BPA should "liquidate reserves" rather than raise rates. A participant stated that BPA should reconsider a forward-looking Cost Recovery Adjustment Clause that would allow BPA to adjust its risk mitigation tools based on forecasts of its financial conditions and future costs. Several participants would like to see more incentives for people to install and use their own power systems.

Response: BPA's financial reserves are an important asset in keeping rates low. In the past, BPA's financial reserves were the first and most effective means to mitigate BPA's exposure to risks from water supply, market price, weather, and the economy. BPA has expanded its access to short-term liquidity through an agreement with the Department of the Treasury. This short-term liquidity reduces the need to hold cash in the BPA Fund, BPA's bank account. It also has removed BPA's need for Planned Net Revenues for Risk, the means for rebuilding its financial reserves, in the FY 2010-2011 rates. BPA's financial reserves and the short-term liquidity work together to reduce the large revenue and cost risks that BPA faces, keeping power rates lower. However, BPA is required by law to set its rates to recover its costs during the period in which the costs are incurred, and cannot use large reserves to justify setting its rates below its costs. The Cost Recovery Adjustment Clause is another important risk mitigation tool that BPA uses to keep rates lower. The Cost Recovery Adjustment Clause BPA currently uses, which looks "backward," meets BPA's need to ensure its payments to the U.S. Treasury. Therefore, BPA does not see a need for a "forward-looking" Cost Recovery Adjustment Clause as suggested by one participant. BPA will continue to manage all of these tools to provide the lowest rates possible consistent with sound business practices.

BPA received participant comments suggesting BPA provide more incentive for people to install and use their own power systems. Through the Conservation Rate Credit (CRC) program, BPA provides funding that can be used for direct application of renewables by individuals, such as solar water heating, photovoltaic systems, micro hydro, and small windmills. BPA provides CRC funding to utilities, and then CRC funds are made available to individuals through their utilities. The level of BPA funding for the CRC is addressed in BPA's Integrated Program Review, the public process that discusses costs just prior to each rate case. The public was invited to participate and provide input into the level of CRC funding as part of the IPR process.

Topic: Rate Case Process	Number of Comments
How can we fight the rate increase?	3
Distrust of local utility management; wants to hear directly from BPA about the proposed rate increase.	1
We hope you pay attention to the comments.	1
Would attend a hearing to provide comments.	1

The recession requires that BPA justify the rate increase to consumers directly, not through the local PUD or media.	1
Opposes BPA's "unilateral" decision to raise rates.	1

Several participants asked how they could stop the rate increase from happening. Another stated a lack of trust of local utility officials and wants to hear from BPA directly. Others wondered what would happen to their comments and if anyone would read them. One participant stated that BPA should justify the rate increase to consumers directly, not through the local utility or local media.

Response: BPA's process for setting rates is based on section 7(i) of the Northwest Power Act. BPA's own procedures added to the process described in the Act and describe the difference between parties and participants. Participants are allowed to submit comments any time within a comment period by U.S. Mail, by e-mail, and through a special Web page, and those comments are added to the official record of the rate case. The BPA Administrator bases his decisions on issues in the rate case on the entire record, including participant comments. In the past, one of the ways BPA told interested persons about the rate case and received comments was through field hearings. Very few people came to those field hearings. In recent years BPA has reduced the number of field hearings, and for this rate case held none at all, to save money. Based on the number of comments BPA received (400), we believe the comment period was long enough and user-friendly enough for people to participate. Near the start of the rate case, BPA sent out a press release, a letter to its customers, and a fact sheet. All these materials were posted to the rate case Web site for the public to view. BPA also briefed the region's congressional members, customer groups, and other stakeholders. BPA briefed its account executives, who communicate directly with customers. It would be too expensive for BPA to send a letter to all consumers in the region to inform them about the rate case or to meet with ratepayers across the region in person. To keep expenses down, BPA expects interested persons to access materials on its Web site or talk with their utility representative for information. We very much appreciate receiving comments from participants, who bring unique viewpoints to the official record of the rate proceeding.

PART III

TR-10 DOCKET

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18.0 PARTIAL SETTLEMENT AGREEMENT

Transmission Services (TS) proposed 2010 transmission rates and rates for the two required ancillary services (Scheduling, System Control, and Dispatch Service and Reactive Supply and Voltage Control from Generation Sources Service) that reflect the terms of the Partial Settlement Agreement that TS entered into with most of the rate case parties. Bermejo *et al.*, TR-10-E-BPA-06, at 2. As noted in section 1.1.2, no rate case party objected to any aspect of the TS proposal for partial settlement. Therefore, TS recommends that the Administrator establish rates consistent with the Partial Settlement Agreement.

The proposed FY 2010-2011 final transmission rates and the ancillary services rates that are included in the Partial Settlement Agreement are unchanged from existing rates. TS determined that existing rates are sufficient for TS to recover its costs during the rate period. *Id*. The rate levels for BPA's 2010 transmission rates and for the ancillary services rates subject to the settlement are provided in Attachment 1 to the Partial Settlement Agreement, Appendix A to this ROD.

Under the partial settlement agreement, the transmission and ancillary services rate schedules are revised as follows:

a) Failure to comply penalty charge:

- changing the rate to a flat 1,000 mills per kilowatthour plus the costs of alternate measures TS takes to manage reliability and monetary penalties imposed on BPA for violation of a reliability standard;
- including in the billing factor kilowatthours not shed, changed, or limited in response to a TS order within 10 minutes;
  adding dispatch orders to the orders that can lead to a failure to comply penalty; and
- clarifying that TS orders to change or limit generation levels will be issued in accordance with Good Utility Practice as defined in the OATT.

Id. at 3-4. TS also agreed to hold a public process to develop a business practice for implementing the revised failure to comply penalty charge, and agreed that it would not assess the charge until it had adopted a final business practice. *See* Partial Settlement Agreement, Appendix A.

b) Unauthorized increase charge:

- changing the rate from two times the applicable transmission rate to the lower of (i) 100 mills per kilowatthour plus the price cap established by FERC for spot market sales of energy in the WECC or (ii) 1,000 mills per kilowatthour;
- changing the billing factor for point-to-point customers to ensure that they are charged for each hour they exceed their reservation rather than only for the highest hour;
- changing the waiver language to make clear that, if TS reduces or waives the UIC, the customer must still pay the underlying transmission charge;
- adopting billing factors for the underlying charge; and

- clarifying the criteria under which TS will waive the UIC.

Id. at 4-5.

Finally, TS updated the Reactive Supply and Voltage Control from Generation Sources Service rate schedule so that the rate is based on current forecasts of billing determinants, added conditional firm service to the availability section of the Network Integration rate schedule, and revised Attachment M to BPA's transmission tariff, which establishes parameters and procedures for redispatch of the Federal hydro system. Attachment M will be submitted to the Commission for approval as an amendment to BPA's tariff. *Id*. at 5-6.

The Administrator agrees that the rates proposed in the Partial Settlement Agreement satisfy BPA's statutory ratemaking standards and will establish these rates in this Record of Decision.

19.0 TRANSMISSION REVENUE REQUIREMENT

19.1 Introduction

BPA is a self-financed power marketing agency within the Department of Energy (DOE). Sales of electric power and transmission services are BPA's primary sources of revenue. *See Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1116 (9th Cir. 1984). BPA's transmission and ancillary services rates are based on the agency's total system costs. Revenues generated from transmission, ancillary services, and power rates must be sufficient to ensure repayment of the Federal investment in the FCRPS over a reasonable number of years after first meeting the Administrator's other costs. 16 U.S.C. § 839e(a)(2)(A) and (B). BPA must also set transmission and ancillary services rates with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates in accordance with sound business principles. 16 U.S.C. § 825s, § 839g, and § 839(a)(l).

The transmission and ancillary services rates established herein are designed to recover BPA's costs as set forth in the transmission revenue requirement. BPA determines generation and transmission revenue requirements using separate repayment studies, consistent with the Commission's 1984 order. *See United States Dep't of Energy--Bonneville Power Admin.*, 26 FERC ¶ 61,096 (1984). Rates to recover the costs set forth in BPA's generation revenue requirement have been established in the WP-10 docket. The costs developed in that docket include charges for ancillary services inputs and other costs incurred by Power Services that are relevant to the transmission function, including, among other costs, charges paid to BPA's Power Services for the annual costs of the U.S. Army Corps of Engineers and U.S. Bureau of Reclamation transmission facilities that are included in the network and utility delivery segments. These costs are incorporated into the transmission revenue requirement and recovered by transmission and ancillary services rates.

Consistent with BPA's statutory obligations, the transmission revenue requirement establishes the level of revenue required to recover all of BPA's costs of transmitting electric power, which include the Federal investment in transmission and transmission-supporting facilities; operations and maintenance (O&M) expenses; transmission marketing and scheduling expenses; the cost of generation inputs for ancillary services and reliability; and all other transmission-related costs incurred by the Administrator. *See* Revenue Requirement Study, TR-10-FS-BPA-01, at 1.

19.2 Revenue Requirement Development

BPA develops its revenue requirement to recover its costs in conformance with its statutory obligations and the financial, accounting, and repayment requirements of the Department of Energy's Order No. RA 6120.2. Revenue Requirement Study, TR-10-FS-BPA-01, Chapter 5.

BPA calculated its transmission revenue requirement for the FY 2010-2011 rate period using a cost accounting analysis consisting of three components:

- Repayment studies are conducted for each year of the two-year rate period to determine the schedule of amortization payments and to project annual interest expense for bonds and appropriations that fund the Federal investment in transmission. Repayment studies include a 35-year repayment period.
- Operating expenses functionalized to transmission and minimum required net revenues (if needed) are projected for each year of the rate test period.
- Annual planned net revenues for risk (PNRR), if any, are determined based on the risks identified, BPA's cost recovery goals, and risk mitigation measures.

Id. at 2.

Based on these analyses, BPA sets the transmission revenue requirement at the revenue level necessary to fulfill BPA's cost recovery requirements. Department of Energy Order No. RA 6120.2 requires that BPA demonstrate the adequacy or inadequacy of its existing rates to recover its costs. BPA conducts a current revenue test to determine whether transmission revenues projected from current rates meet cost recovery requirements for the rate test and repayment periods. If the current revenue test indicates that cost recovery and risk mitigation requirements can be met, BPA can extend current rates. BPA determined that current rates were insufficient to demonstrate cost recovery because of costs associated with certain ancillary and control area services. *Id*. Accordingly, the current revenue test was not met.

BPA then conducts a revised revenue test to determine the adequacy of the proposed rates. The revised revenue test determines whether projected revenues from proposed rates will meet cost recovery requirements for the rate test and repayment periods. Because the results of the current revenue test demonstrated the sufficiency of the current rates for transmission and for certain ancillary services rates, those rates were continued at current levels for the revised revenue test. BPA has revised the remaining rates to ensure cost recovery. The revised revenue test demonstrates that the rates proposed are sufficient to meet cost recovery requirements for the rate test and repayment periods. *Id*.

19.3 Cost Obligations and Assumptions Used in Calculation of the Revenue Requirement

19.3.1 Use of Reserves to Finance Capital Projects

As in the previous three rate cases, BPA plans to use $15 million of designated Transmission Services cash reserves in each year of the FY 2010-2011 rate period (or a total of $30 million in the two-year rate period) as a funding source for transmission capital programs, rather than using Treasury borrowing authority. This reserve financing assumption is included in the rate period revenue requirements. Homenick *et al.*, TR-10-E-BPA-05, at 7.

19.3.2 Other Uses of Reserves

Over the last several years, revenues from transmission rates provided funds in excess of cash requirements, resulting in a buildup of cash reserves attributed to Transmission Services. To induce settlement and allow BPA to maintain transmission rates at current levels, the Administrator authorized the use of up to $40 million of cash reserves to fund a portion of the O&M expenses during the rate period. Accordingly, for this rate period, transmission rates will be based on TS net expenses, after application of cash reserves.

19.4 Repayment Studies

Repayment studies are the first step in determining revenue requirements. The studies establish the schedule of annual U.S. Treasury amortization for the rate test period and the resulting interest payments.

In this rate filing, as in the previous transmission rate filing, the repayment period is set at 35 years. This study horizon is consistent with the longest term bonds that BPA issues (BPA issues bonds of up to 35 years for transmission investments and up to 15 years for environmental investments for transmission maintenance). BPA fully repays all outstanding appropriations and bonds for the transmission system within a 35-year period under a schedule determined to result in the lowest levelized debt service stream necessary to repay all transmission obligations within the required repayment period. Revenue Requirement Study, TR-10-FS-BPA-01, at 13-14.

The Revenue Requirement Study includes the results of transmission repayment studies for each of the two years in the rate test period, fiscal years 2010 and 2011. In conducting the repayment studies, BPA includes outstanding and projected transmission repayment obligations on appropriations and on bonds issued to the U.S. Treasury. Funding for replacements projected during the repayment period also is included in the repayment study, consistent with the requirements of RA 6120.2. *Id.* at 14.

19.5 Planned Net Revenues for Risk

In the 1993 Final Rate Proposal BPA determined that, as a long-term policy, it would set its rates to maintain financial reserves sufficient to achieve a 95 percent probability of meeting Treasury payments in full and on time for each two-year rate period. 1993 Final Rate Proposal, Administrator's ROD, WP-93-A-02, at 72-73.

The probability of meeting its Treasury payment obligation is the primary measure of BPA's ability to recover its costs. BPA has applied the same risk analysis in the FY 2010-2011 rate period as in the past. Homenick *et al.*, TR-10-BPA-05, at 6. To achieve the above Treasury Payment Probability (TPP), BPA used the following risk mitigation tools:

1. *Starting reserves*: Starting financial reserves include cash and the deferred borrowing balance attributed to the transmission function. BPA projects

transmission reserves to total $157 million at the beginning of FY 2010. Revenue Requirement Study, TR-10-FS-BPA-01, at 7.

2. *Planned Net Revenues for Risk*: PNRR is a component of the revenue requirement that is added to annual expenses. PNRR adds to cash flows so that financial reserves are sufficient to mitigate short-run volatility in costs and revenues and achieve the TPP goal. No PNRR were required to meet the TPP standard in this rate filing. *Id*. at 8.

3. *Two-Year Rate Period*: The rates established in this record will be effective for a two-year rate period. The ability to revise rates after two years, or more frequently if necessary, serves as an important risk mitigation tool. A two-year rate period limits the effects of uncertainty. *Id*. Moreover, even though the Administrator is adopting the rate settlement, BPA retains the right to initiate a process to raise rates during the rate period if necessary.

19.6 Transmission Risk Analysis

To quantify risks, BPA used a Monte Carlo simulation method to analyze the effects of uncertainty in costs and revenues on transmission cash flows. The analysis estimated the probability of successful Treasury payment (on time and in full) for both years of the rate period. Successful Treasury payment is deemed to occur when the end-of-year transmission cash reserve, after Treasury payments are made, is sufficient to cover the transmission liquidity reserves requirement of $20 million. The liquidity reserves threshold is based on the monthly net cash flow patterns and requirements for the transmission function. *Id*.

The risk analysis covers the period FY 2009 through FY 2011. This timeframe is used to permit analysis of the change in revenues, costs, and accrual-to-cash adjustments that is expected to occur between the development of the final rate proposal and the end of the rate period. The advantage to this approach is that cash reserves at the start of the FY 2010-2011 rate period may be estimated, thus helping to define the starting conditions for the rate period. *Id*.

The foundation of the Monte Carlo simulation is a transmission financial spreadsheet model that estimates the effects of risk and risk mitigation on end-of-year cash reserves on the likelihood of successful Treasury payment during the rate period. Cash reserve levels at the end of the fiscal year determine whether BPA is able to meet its Treasury payment obligation. *Id*. If cash reserves are sufficient to cover working capital requirements at the end of the fiscal year, it can be assumed that the Treasury payment was made in full and on time that fiscal year. End-of-year cash reserves during the rate period are the main outcome of interest in the model. *Id*.

The transmission risk analysis simulation performed for this rate case demonstrated that BPA achieves the 95 percent Treasury Payment Probability standard for the FY 2010-2011 rate period. *Id*. at 3. The risk analysis simulation included the use of up to $70 million in transmission reserves to partially fund O&M expenses and capital projects.

20.0 ANCILLARY AND CONTROL AREA SERVICES RATE DESIGN

Ancillary services are needed with transmission service to maintain reliability within and among the Balancing Authority Areas affected by transmission service. Bermejo *et al.*, TR-10-E-BPA-07, at 2. BPA offers six ancillary services: 1) Scheduling, System Control, and Dispatch Service; 2) Reactive Supply and Voltage Control from Generation Sources; 3) Regulation and Frequency Response Service; 4) Energy Imbalance Service; 5) Operating Reserve – Spinning Reserve Service; and 6) Operating Reserve – Supplemental Reserve Service. *Id*.

BPA also offers control area services to meet the reliability obligations of generation or loads in the BPA Balancing Authority Area (formerly known as the BPA Control Area). Bermejo *et al.*, TR-10-E-BPA-07, at 2-3. BPA offers five control area services: 1) Regulation and Frequency Response Service; 2) Generation Imbalance Service; 3) Operating Reserve – Spinning Reserve Service; 4) Operating Reserve – Supplemental Reserve Service; and 5) Wind Balancing Service. *Id*.

In the Initial Proposal, Staff proposed rate provisions and rate levels for the Ancillary and Control Area Service rates that were not included in the Partial Settlement Agreement. This section of the Record of Decision addresses the remaining issues in the TR-10 sub-docket.

20.1 Wind Balancing Service

20.1.1 Introduction

BPA provides Wind Balancing Service as a Control Area Service to wind generators in the BPA Balancing Authority Area. Wind Balancing Service supports within-hour movement of wind generation and maintains the balance between loads and resources. Study and Documentation for 2010 Ancillary Service and Control Area Services, TR-10-E-BPA-03, at 16-17. As a Balancing Authority Area, BPA must continuously maintain this balance. Bermejo *et al.*, TR-10-E-BPA-07, at 17. Transmission Services relies on generation inputs supplied from Power Services to follow within-hour variations of wind resources to provide Wind Balancing Service. BPA must utilize balancing reserves to maintain compliance with NERC and WECC reliability standards. *Id*.

The Wind Balancing Service rate (WI-10 rate) establishes charges for each of the three components of Wind Balancing Service: regulating reserves (which compensate for moment-to-moment differences between generation and load), following reserve (which compensates for larger differences occurring over longer periods of time during the hour), and imbalance reserves (which compensate for differences between the generator's schedule and the generation during an hour). Wind generators within BPA's Balancing Authority Area must either purchase this service from BPA or make alternative comparable arrangements to satisfy their within-hour balancing service obligation. Study and Documentation for 2010 Ancillary Service and Control Area Services, TR-10-E-BPA-03, at 17.

20.1.2 Issues

Issue 1

Whether BPA should modify the WI-10 rate design to enable wind generators to self-supply one or more components of wind integration.

Parties' Positions

Iberdrola suggests that BPA separate out the components of its WI-10 rate to allow customers to self-supply components of wind integration service and receive either an exemption or a credit for those portions of the rate. Absent a mechanism to compensate for implementation of self-supply or other operational solutions that reduce one or more components of the reserve requirement, Iberdrola contends, wind generators would not realize any rate benefits from reducing Bonneville's need to hold reserves for these components. Iberdrola Br., TR-10-B-IR-01, at 17; Iberdrola Br. Ex., TR-10-R-IR-01, at 10.

NWG suggests that BPA also should separate out each of the different "per-integrated MW" Wind Integration Service rates into the constituent component rates. NWG says that this rate design would enable wind generators to self-supply one or more of the components and to pay only for the within-hour balancing components that BPA provides. NWG Br., TR-10-B-NG-01, at 40-41.

Both MSR and PPC *et al.* support unbundling of Wind Balancing Service into its constituent components. MSR Br. Ex., TR-10-R-MS-01, at 3-4; PPC *et al.* Br. Ex., TR-10-R-JP12-01, at 23-24.

BPA Staff's Position

The issue of breaking out the individual components to the WI-10 rate was first raised in party briefs, and Staff did not have an opportunity to respond.

Evaluation of Positions

Both Iberdrola and NWG suggest that BPA unbundle the individual components of Wind Balancing Service (*e.g.*, regulation, following, and imbalance) to facilitate self-supply of one or more of the components during the rate period. Iberdrola Br., TR-10-B-IR-01, at 16; Iberdrola Br. Ex., TR-10-R-IR-01, at 10; NWG Br., TR-10-B-NG-01, at 40.

This proposal has merit. BPA is working with its stakeholders to facilitate development of self-supply options and protocols to enable self-supply. To be successful in this endeavor, BPA's rate design should not impede the ability of wind developers to choose non-BPA sources of wind integration services.

Despite the challenges associated with self-supply and the transfer of wind balancing responsibilities to new and independent balancing authorities, BPA agrees with Iberdrola and NWG that an unbundled WI-10 rate would better serve the needs of the region. By unbundling the individual components of Wind Balancing Service (regulation, following, and imbalance), BPA will maintain flexibility to accommodate self-supply or the transfer of balancing responsibilities to independent Balancing Authority Areas if such options materialize over the rate period. *See also* section 13.4, Issue 10 (discussing the method used to unbundle the WI-10 rate). In Briefs on Exceptions, both MSR and PPC *et al.* indicate support for this proposal. MSR Br. Ex., TR-10-R-MS-01, at 3-4; PPC *et al.* Br. Ex., TR-10-R-JP12-01, at 23-24.

Iberdrola, NWG, and PPC *et al.* support a rate credit for each component that a wind generator self-supplies. Iberdrola Br. Ex., TR-10-R-IR-01, at 10; NWG Br., TR-10-B-NG-01, at 40-41; PPC *et al.* Br. Ex., TR-10-R-JP12-01, at 24. Specifically, PPC *et al.* recommend that BPA should base rate credits for self-supply of one or more individual components of Wind Balancing Service on an after-the-fact determination of the amount of balancing reserves that BPA did not have to set aside or deploy for the wind generator during the delivery hour. PPC *et al.* Br. Ex., TR-10-R-JP12-01, at 24.

BPA agrees with the rate case parties that a rate credit is appropriate for each component of Wind Balancing Service that a wind generator self-supplies. BPA disagrees with PPC *et al.*, however, that an after-the-fact calculation of the credit for self-supply is necessary. BPA will not set aside balancing reserve for any portion of Wind Balancing Service that is self-supplied. Thus, the credit can be calculated before the delivery hour. BPA notes that it is on track to establish a business practice for self-supply that will contain the criteria and protocols for self-supply of one or more components of Wind Balancing Service. BPA will address PPC *et al.*'s suggestions regarding implementation of self-supply in the business practice development process.

Decision

BPA will unbundle the WI-10 rate and post the rate associated with each component of Wind Balancing Service (regulation, following, and imbalance). A party that self-supplies one or more components of Wind Balancing Service consistent with BPA's business practices and reliability requirements will receive a credit for that component or components.

Issue 2

Whether BPA should adopt a mid-rate period adjustment mechanism in the WI-10 rate design to enable BPA to reduce the rate to reflect reductions in the amount of reserves that BPA is required to hold due to 1) wind generators electing to self-supply or 2) wind generators transferring balancing responsibilities to other balancing authorities.

Parties' Positions

NWG states that BPA should rerun the necessary studies to calculate the total Wind Balancing Service rate for different levels of wind self-supplying or leaving BPA's Balancing Authority Area. NWG states that "BPA should be prepared to adjust the FY 2010-11 Wind [Balancing] rate mid-rate period to account for any significant changes in the amount of wind BPA is actually integrating." NWG Br., TR-10-B-NG-01, at 41.

Iberdrola argues that, if BPA increases its wind rate by 50 percent or more over the current FY 2009 rate of $0.68/kW/mo., the rate should include a rate adjustment clause for self-supply. Iberdrola Br., TR-01-B-IR-01, at 6. Iberdrola also suggests that BPA should be prepared to conduct an expedited 7(i) rate proceeding within the rate period to deal with revenue variability issues if necessary. Skidmore, Oral Tr. at 68.

NWG and Iberdrola suggest that, if BPA adopts the WI-10 rate, wind developers may create independent balancing authorities to reduce costs. Iberdrola Br., TR-10-B-IR-01, at 4; NWG Br., TR-10-B-NG-01, at 3. Iberdrola asserts that BPA's proposed WI-10 rate has reached a level that is prohibitive and fosters disaggregation of balancing authority areas. Iberdrola Br., TR-10-B-IR-01, at 5. Thus, Iberdrola claims, BPA should provide an adjustment in its WI-10 rate to accommodate self-supply or the transfer of balancing responsibilities to other balancing authorities. *Id.*

BPA Staff's Position

The issue of a mid-period adjustment was first mentioned in party briefs, and Staff did not have an opportunity to respond. However, BPA Staff does not forecast significant amounts of self-supply over the rate period.

Evaluation of Positions

Both NWG and Iberdrola suggest that the WI-10 rate should include a rate adjustment clause that accounts for the reduction in BPA's reserve requirement during the rate period if wind generators self-supply. Iberdrola Br., TR-10-B-IR-01, at 6; NWG Br., TR-10-B-NG-01, at 6. Iberdrola and NWG suggest that self-supply of one or more of the components of the WI-10 rate would result in BPA having to set aside less balancing reserves over the rate period; therefore, the total costs associated with setting aside balancing reserves should decrease for the remaining WI-10 ratepayers. Iberdrola Br., TR-10-B-IR-01, at 16-17; NWG Br., TR-10-B-NG-01, at 42-43.

If the rate case parties' goal of a mid-period adjustment is to reduce the WI-10 rate, a rate adjustment clause in the WI-10 rate design is unnecessary. The WI-10 rate establishes a maximum charge and preserves the Administrator's discretion to offer a discount if appropriate. Therefore, it is unnecessary to include a rate adjustment clause in the rate schedule. A mid-rate period adjustment clause would be administratively cumbersome to implement, given the complexity of internal processes and procedures involved in recalculating power and transmission rates. Given the low likelihood that significant self supply will materialize over the rate period, BPA disagrees that it is necessary to adopt a mid-rate period adjustment clause.

As discussed above, BPA is actively engaged with its stakeholders in developing self-supply options and protocols. The concept of "self-supply" or self-provision of any of the components of Wind Balancing Service is highly technical and complex, however. To enable self-supply of one or more of the components of Wind Balancing Service, BPA needs lead time to develop new systems and processes. BPA will need to modify the automatic generation control (AGC) system, install new communications equipment, and establish a business practice to provide the eligibility criteria, notice provision, and term for self-supply of one or more components of the service. BPA must also obtain public review and comment of any new self-supply protocols.

BPA is making significant progress on this front. Through its joint efforts with the wind community, BPA expects the development of efficient and reliable methods that will be available to enable self-provision of any of the components of Wind Balancing Service during the rate period. Given the lead time and complexity involved with self supply, implementation will begin on October 1, 2010.

In its Brief on Exceptions, Iberdrola notes that it will seek to self-supply generation imbalance capacity for a substantial portion of its wind fleet. Iberdrola Br. Ex., TR-10-R-IR-01, at 11. Iberdrola states that BPA should preserve its discretion to make a mid-rate period adjustment and encourages BPA not to preclude such an adjustment in its final decision. *Id*. at 10-11. As noted above, BPA has the discretion to downwardly adjust the WI-10 rate if appropriate. While BPA acknowledges the potential for Iberdrola to seek self-supply options, BPA does not expect that the amount of self supply over the rate period will materially impact the rate level.

BPA also does not find it necessary to include an adjustment clause in its WI-10 rate design to address the possibility of customers creating an independent balancing authority. As discussed in section 13.2.2, Issue 1, a wind developer must weigh many variables before adopting an alternative to BPA's Wind Balancing Service. Hall, Oral Tr. at 40; Skidmore, Oral Tr. at 76. Although the formation of an independent balancing authority area could be an alternative to BPA's Wind Balancing Service, many regulatory and infrastructure requirements are likely to affect the cost-effectiveness of that alternative. It also requires considerable time to finalize the requisite reliability certification process and infrastructure improvements to create a new and independent balancing authority. Thus, BPA does not forecast any significant impact from the formation of independent balancing authorities for the rate period.

NWG and Iberdrola appear to assume that self-supply of one or more components of the WI-10 rate will result in a reduction to the WI-10 rate because BPA can reduce the amount of balancing reserves it sets aside. NWG Br., TR-10-B-NG-01, at 40-41; Iberdrola Br. Ex., TR-10-R-IR-01, at 11. Self-supply of one or more components of the WI-10 rate will not automatically result in a linear reduction (or necessarily any reduction) to the WI-10 rate. Ancillary and control area service rates rely on generation input costs that are allocated for the rate period in the power rate proceeding. Absent a change in the power revenue requirement, a reduction in the capacity system uses (*e.g.*, through self-supply of Wind Balancing Service) would increase the wind balancing rate, because fewer megawatts of installed wind capacity would be available over which to allocate the revenue requirement. *See* Generation Inputs Study and Study Documentation, WP-10-E-BPA-08. Notably, no party to the rate case proposed a viable formula rate alternative for the WI-10 rate.

If BPA observes a significant amount of self-supply during the rate period, however, and if such self-supply would result in a lower overall WI-10 rate, BPA is prepared to consider discounting the WI-10 rate. As noted, the proposed WI-10 rate schedule preserves the Administrator's existing ability to apply a discount.

At oral argument, Iberdrola suggested that BPA should be prepared to conduct an expedited 7(i) proceeding within the rate period to deal with revenue variability issues if necessary. Skidmore, Oral Tr. at 68. While BPA agrees that it has the statutory authority to conduct such a proceeding, as explained above, self-supply may have a minimal effect on the rate, and BPA does not expect a time-consuming and costly rate proceeding to be necessary or feasible during the rate period.

Finally, in response to NWG's suggestion that BPA rerun its studies to calculate any change in the reserve requirement that may result if large amounts of wind generation elect to self-supply during the rate period, BPA does not find it necessary to conduct hypothetical studies at this time. As noted above, BPA does not anticipate a significant difference in the rate.

Decision

BPA will not adopt a mid-rate period adjustment mechanism to account for self-supply of Wind Balancing Service. If BPA observes significant amounts of self supply during the rate period, BPA will evaluate the appropriateness of a discount to the WI-10 rate.

Issue 3

Whether BPA should adopt two Wind Balancing Service rates based on different persistence scheduling accuracy levels.

Parties' Positions

OPUC recommends that the Administrator adopt two different Wind Balancing Service rates: one based on 30-minute persistence scheduling accuracy, and one based on 45-minute persistence scheduling accuracy. OPUC Br., WP-10-B-PU-01, at 13. OPUC explains that basing the rate on a forecast accuracy level less than what can be achieved by wind generators will not provide incentives to improve forecasting accuracy. OPUC argues that adopting dual rates based on 30- and 45-minute persistence accuracy levels would appropriately incentivize Northwest wind generators to improve and maintain their scheduling accuracy and would fairly price Wind Balancing Service. *Id.*

PPC *et al.* also argue for a dual rate option, but in connection with a proposed ratchet charge. PPC *et al.* Br., WP-10-B-JP11-01, at 40-41; *see* section 20.1.2, Issue 4, below for more discussion of the proposed ratchet charge. According to PPC *et al.*, if BPA adopts a WI-10 rate based on 45-minute persistence scheduling accuracy, BPA should also adopt a backstop wind rate based on 60-minute persistence scheduling accuracy. The backstop wind rate would apply to wind generators unable to meet 45-minute persistence scheduling accuracy during the rate period, or to all wind generators if BPA is unable to enforce DSO 216. Baker *et al.*, WP-10-E-JP6-1, at 20; PPC *et al.* Br., TR-10-B-JP11-01, at 40-41.

BPA Staff's Position

A dual rate design would increase complications with BPA's Generation Reserve Forecast and billing systems. A dual rate design also would require BPA to speculate regarding the costs to allocate among the two WI-10 rates, depending on the rate that applies to each wind generator, resulting in significant risk to the ratesetting process. Mainzer *et al.*, WP-10-E-BPA-41, at 38.

Evaluation of Positions

Both OPUC and PPC *et al.* suggest that, because of the different levels of scheduling accuracy among wind generators, BPA should set two separate rates to enable BPA to charge each wind generator the rate that best reflects that wind generator's level of scheduling accuracy. OPUC Br., WP-10-B-PU-01, at 13; PPC *et al.* Br., TR-10-B-JP11-01, at 40-41. According to OPUC, the evidence in the record demonstrates that some wind generators are able to meet 30-minute persistence, while others are able to meet 45-minute persistence. OPUC Br., WP-10-B-PU-01, at 13; *see also* section 13.3.2.3 for discussion of the issues related to assumptions about persistence scheduling accuracy.

In contrast, PPC *et al.* argue that the demonstrated scheduling accuracy of wind is now at 60-minute persistence. PPC *et al.* Br., TR-10-B-JP11-01, at 33-34. PPC *et al.* suggest that if the Administrator decides to adopt a WI-10 rate based on 45-minute persistence scheduling accuracy, BPA also should set a backstop rate based on a 60-minute persistence level of accuracy. *Id*. at 40. PPC *et al.* suggest that, if a wind generator is unable to achieve 45-minute persistence scheduling accuracy, BPA should charge the generator a rate based on 60-minute persistence. *Id*. at 40-41.

Although these suggestions have merit, they add unwarranted complexity given other changes BPA is making. As Staff testified, BPA is faced with a considerable implementation effort to manage balancing reserves based on a single persistence scheduling accuracy over the rate period:

> A two-rate alternative to the Initial Proposal has certain appeal, but adds significant complexity to an already complex set of assumptions, methodologies, and rate design for wind. BPA is faced with a considerable implementation effort to manage balancing reserves based on a single-persistence scheduling accuracy over the rate period. Adopting multiple forecast levels over the rate period would further complicate that task and introduce more risks.

Bermejo *et al.*, TR-10-E-BPA-10, at 19 (internal citations omitted). Accordingly, the added complexity under either OPUC's or PPC *et al.*'s proposal makes a dual rate unfeasible for this rate period. For example, a dual rate design would require BPA to adjust its billing protocols to allow for two different charges to wind generators within BPA's Balancing Authority Area. In contrast, a single WI-10 rate design would avoid these complications.

BPA agrees that under OPUC's suggestion, a dual rate design is likely to incentivize wind generators that are unable to meet 30-minute persistence scheduling accuracy to improve their scheduling accuracy. However, BPA does not find it necessary to adopt a dual rate design for the rate period. Improving scheduling accuracy is an important goal for BPA and its customers, and the WI-10 rate plays an important role in that effort. In combination with the WI-10 rate, BPA's Wind Integration Team initiatives and the scheduling incentives provided by BPA's Generation Imbalance Service and Persistent Deviation Penalty charge should be sufficient to motivate wind generators to improve scheduling accuracy. Mainzer *et al.*, WP-10-E-BPA-41, at 34.

Finally, BPA notes, OPUC states in its Brief on Exceptions that an adjustable rate will also incentivize forecasting accuracy while maintaining system reliability. OPUC Br. Ex., WP-10-R-PU-02, at 2. BPA discusses its adoption of an adjustable rate design in Issue 5 below.

<u>Decision</u>

BPA will retain a single WI-10 rate for Wind Balancing Service. However, BPA will adopt an adjustable rate design, as discussed in Issue 5.

<u>Issue 4</u>

Whether to adopt a ratchet charge if BPA adopts a WI-10 rate based on a 45-minute persistence scheduling accuracy.

<u>Parties' Positions</u>

PPC *et al.* recommend that BPA should adopt a ratchet charge in addition to the WI-10 rate. PPC *et al.* Br., TR-10-B-JP11-01, at 40-41; *see also* Issue 3 above. The ratchet charge would be added to the base WI-10 rate for all interconnected plants if at any time BPA's proposed DSO 216 or successor DSO is set aside or cannot be enforced, or if BPA's proposed reliability requirement updates in interconnection agreements cannot be enforced. Baker *et al.*, TR-10-E-JP6-1, at 20.

In the alternative, PPC *et al.* suggest that the ratchet charge could apply in FY 2011 to those wind plants that do not meet or exceed the 45-minute persistence scheduling accuracy level during FY 2010 and to new wind plants that do not meet or exceed the 45-minute persistence scheduling accuracy level within three months of their full service date in FY 2011. *Id*. BPA would credit any monies BPA collects from the ratchet charge to Power Services. *Id*. PPC *et al.* state that this alternative rate design would reward those wind generators that improve forecasting accuracy beyond the 60-minute level and would not harm other customers in the event DSO 216 is not successfully implemented or individual wind generators fail to meet the 60-minute persistence accuracy level. *Id*.

Cowlitz argues that BPA should reject the PPC *et al.* proposal because it will either result in an overcharge for Wind Balancing Service or create a discriminatory ratchet targeted at wind generators. According to Cowlitz, the structure of the charge is flawed because it is triggered if the DSO or successor DSO is set aside. Cowlitz Br., TR-10-B-CO-01, at 18-19. If the DSO is set aside or if it cannot be enforced as written, the solution would be to revise the DSO to correct any flaws. *Id*. at 19. Cowlitz urges the Administrator to reject the ratchet or, if the Administrator adopts a ratchet, credit monies to the better wind forecasters rather than to power customers. *Id*. at 19-20.

NWG contends that the PPC *et al.* proposal to adopt an additional "wind only" scheduling accuracy penalty of $1/kW/mo is erroneous and should be rejected. According to NWG, such a penalty does not appear to be cost-based, seems difficult to administer, and is excessive and unnecessary. NWG Br., TR-10-B-NG-01, at 14.

Iberdrola states that a ratchet charge for wind lacks any cost basis, is unnecessary to incentivize accurate scheduling behavior, and would be inappropriate and unduly punitive. Iberdrola Br. Ex., TR-10-R-IR-01, at 11.

BPA Staff's Position

Staff does not agree with the PPC *et al.* ratchet proposal. Mainzer *et al.*, WP-10-E-BPA-41, at 44. Staff notes that there does not appear to be a cost basis to support a ratchet penalty. *Id.* There are also significant implementation challenges associated with a dual rate design. *See also* Issue 3 above for discussion on the dual rate design alternative.

Evaluation of Positions

PPC *et al.* argue that the ratchet charge is necessary because BPA cannot enforce better scheduling accuracy by the wind fleet unless BPA has the operational means to control wind ramps or can control the amount of balancing reserves it supplies. Baker *et al.*, TR-10-E-JP6-1, at 21.

BPA agrees with PPC *et al.* that if BPA is unable to enforce its proposed DSO, BPA's ability to reliably integrate and manage variable wind power in the BPA Balancing Authority Area would be stressed. As Staff testified, without the reliability and operational requirements of the proposed DSO, BPA would not be able to integrate wind generation and maintain system reliability:

> The purpose of the DSO is to establish the necessary reliability protocols and mechanisms to protect and responsibly manage system reliability. The DSO is a critical and necessary component of BPA's ability to reliably integrate large amounts of variable wind generation into the BPA Balancing Authority.

Mainzer *et al.*, WP-10-E-BPA-41, at 39. Therefore, as discussed further in Issue 5 below, as an alternative to the ratchet charge BPA is preserving its discretion to increase the WI-10 rate and the amount of balancing reserves set aside to provide Wind Balancing Service if BPA is prevented by a legal challenge from implementing DSO 216 or if participants in the Pacific Northwest utility industry request an increase in the amount of balancing reserves.

PPC *et al.* argue that a ratchet charge is necessary to curb the use of balancing reserves in excess of BPA's forecast. PPC *et al.* Br., TR-10-B-JP11-01, at 40. PPC *et al.* state that the ratchet charge would reward those wind generators that improve forecasting accuracy beyond the 60-minute level and hold requirements customers harmless if BPA could not successfully implement its DSO or individual wind generators fail to meet the 60-minute persistence scheduling accuracy. PPC *et al.* Br., TR-10-B-JP11-01, at 40-41.

The adjustable rate mechanism BPA is adopting should satisfy PPC *et al.*'s concern. In any case, BPA expects the combination of the Wind Integration Team initiatives, Generation Imbalance Service, and Persistent Deviation Penalty charge offer an appropriate set of incentives to improve and maintain wind generation scheduling accuracy over the rate period. Mainzer *et al.*, WP-10-E-BPA-41 at 34; *see also* section 13.3.2.3, Issue 3.

In contrast to PPC *et al.*, Cowlitz, NWG, and Iberdrola state that a ratchet charge is unnecessary. BPA agrees with Cowlitz that, if DSO 216 cannot be enforced as written, the ideal solution is to revise it to correct any flaws. That argument assumes, however, that, after a challenge, BPA is able to revise the DSO in a way that still maintains system reliability, and to do so in a timely fashion. BPA is adopting an adjustable rate mechanism in case this scenario becomes unfeasible.

Decision

BPA will not adopt a ratchet charge.

Issue 5

Whether the Administrator should preserve the flexibility to increase the WI-10 rate level with a commensurate increase in the amount of balancing reserves set aside for Wind Balancing Service in response to a request by the industry, or if DSO 216 becomes unenforceable because of a legal challenge.

Parties' Positions

Cowlitz PUD opposes any BPA proposal to retain discretion to revise the WI-10 rate mid-rate period if BPA adopts a 30-minute persistence assumption. Cowlitz Br. Ex., TR-10-R-CO-01-CC01, at 3.

NWG does not object to a mid-rate period adjustment if BPA also considers the possibility of a downward adjustment in the amount of reserves and corresponding rate level if the scheduling accuracy of wind generators and other factors cause BPA to use less reserves than forecasted. NWG Br. Ex., TR-10-R-NG-01, at 9-10.

Snohomish states that the Administrator should reserve discretion to adjust the balancing reserve levels downward from a level based on 45-minute persistence scheduling accuracy instead of an upward adjustment from 30-minute persistence scheduling accuracy. Snohomish Br. Ex., TR-10-R-SN-01, at 9.

OPUC supports the adoption of an adjustable Wind Balancing Service rate that is based initially on a 45-minute persistence assumption for the reserve forecast but can be downwardly adjusted to a rate level associated with 30-minute persistence scheduling accuracy. OPUC Br. Ex., WP-10-R-PU-02, at 1-2.

BPA Staff's Position

This proposal was first raised in response to rate case party briefs, and Staff has not had an opportunity to respond.

Evaluation of Positions

BPA has emphasized that there is a tradeoff between the quality of Wind Balancing Service and the level of the lower WI-10 rate. After issuing the Draft Record of Decision, BPA asked the parties to state whether they preferred a rate based on 30-minute persistence scheduling accuracy and greater use of DSO 216, or a rate based on 45-minute scheduling accuracy. The wind generators have expressed their preference for a lower WI-10 rate, agreeing to accept the risk of increased use of DSO 216.

The preferences of these parties are only one element in BPA's decision regarding the WI-10 rate. As discussed in section 13.3.2.3, however, BPA believes that the combination of DSO 216 and its other incentives for accurate scheduling allow it to reliably adopt a rate based on 30-minute persistence scheduling. BPA does recognize that it cannot predict with certainty the degree to which it will have to implement DSO 216. Although the wind parties have acknowledged this risk, either they or others in the region may believe that it is preferable to implement DSO 216 less often. In addition, it is possible that BPA will be prevented from fully implementing DSO 216.

Therefore, under these circumstances BPA is retaining discretion to increase the amount of balancing reserves it sets aside for within-hour wind balancing and to increase the WI-10 rate accordingly. In addition, BPA's decision to retain this discretion makes the adoption of a rate based on 30-minute persistence accuracy even more viable.

Cowlitz PUD argues that if BPA increases the WI-10 rate within the rate period, BPA would collect from both power and transmission customers for the same reserve costs. Cowlitz Br. Ex., TR-10-B-CO-01, at 3. According to Cowlitz, if BPA is concerned that the 30-minute persistence scheduling accuracy assumption may produce unacceptable operational limitations under DSO 216, BPA should wait until the next rate case before deciding whether actual experience and a reasonable projection warrant moving away from the 45-minute persistence assumption. *Id*.

BPA does not expect to have to exercise its discretion to increase the rate. Therefore, BPA does not expect to over-recover costs. Given the complexity of adjusting the PF rate to account for an overrecovery and the unlikelihood that the rate will increase, BPA is not adjusting the PF rate or including an adjustment mechanism in the PF rate at this time. If BPA does increase the WI-10 rate during the rate period, BPA will address any over-recovery issues in the next rate proceeding to ensure that BPA does not over-recover costs from PF customers.

NWG states that it supports a mid-period rate adjustment clause, but only if the clause allows for a downward adjustment in the rate as well, if, because of improved wind scheduling accuracy and other factors, BPA needs less reserves than forecast. NWG Br. Ex., TR-10-R-NG-01, at 9-10. Nothing in the rate case record suggests, however, that the wind fleet will achieve better than 30-minute scheduling accuracy during the rate period. Since BPA is adopting a WI-10 rate based on 30-minute persistence scheduling accuracy, BPA finds no reason to adopt a downward adjustment clause for the rate.

Finally, both Snohomish and OPUC suggest that BPA should reserve discretion to downwardly adjust the WI-10 rate and corresponding balancing reserve levels from a WI-10 rate based on 45-minute persistence scheduling accuracy. For the reasons discussed in section 13.3.2.3, BPA is adopting a WI-10 rate based on 30-minute persistence scheduling accuracy. Thus, BPA disagrees with Snohomish and OPUC's suggestion.

Decision

BPA will preserve its discretion to increase the WI-10 rate and commensurate level of balancing reserves to a level based on 45-minute persistence scheduling accuracy if the industry asks the Administrator to increase the level of balancing reserves to provide Wind Balancing Service and the Administrator believes the increase is warranted, or if material elements of DSO 216 become unenforceable because of a legal challenge. BPA will conduct a public process before making such a decision.

Issue 6

Whether BPA should replace the Wind Balancing Service rate with a Generation Imbalance Service rate that incorporates a capacity-based charge.

Parties' Positions

NWG proposes that BPA should replace the Wind Balancing Service rate with a Generation Imbalance Service rate that incorporates a capacity-based charge. NWG Br., TR-10-B-NG-01, at 43.

BPA Staff's Position

Because the WI-10 rate recovers costs for regulation and following in addition to the costs of capacity for generation imbalance, eliminating the WI-10 rate would result in under-recovery of BPA's costs.

Evaluation of Positions

NWG suggests that BPA replace its WI-10 rate with a capacity charge under the Generation Imbalance Service rate. NWG Br., TR-10-B-NG-01, at 43. In rebuttal testimony, Staff disagreed with NWG's proposal and explained that the WI-10 rate recovers more than the costs for imbalance capacity:

> The WI rate recovers more than the capacity costs for generation imbalance service. The WI rate recovers the within-hour capacity costs of following, regulation, and imbalance of wind generation. Mainzer *et al*., WP-10-E-BPA-22. BPA sets aside capacity (*i.e.*, reserves) before the hour to handle all within-hour differences between the submitted schedule and actual wind generation…. We note that NWG does not propose an alternative rate design, but only speculates that alternatives are available to the Initial Proposal.

Bermejo *et al.*, TR-10-E-BPA-10, at 20. As Staff explained, replacing the WI-10 rate with a capacity charge under generation imbalance service would not recover BPA's costs for following and regulation capacity.

NWG also argues that from an operational perspective, there is no distinction among the within-hour reserves used for wind balancing, generation imbalance, and energy imbalance. NWG Br., TR-10-B-NG-01, at 30; NWG Br. Ex., TR-10-R-NG-01, at 14. NWG states that the lack of operational distinction between the types of reserves used for the different services indicates that there is no adequate justification for applying a capacity charge only to wind generators in the provision of imbalance services. *Id*.

NWG's argument is based on a misunderstanding of the differences between BPA's ancillary and control area services. Generation and Energy Imbalance Services are energy-only services that are designed to compensate BPA for the energy it must supply to account for the difference between average hourly energy supplied versus that scheduled. BPA does not set aside reserves to provide this service.

In contrast, the within-hour variability of wind generation has driven the need to set aside significant amounts of balancing reserve to adequately plan, manage, and preserve reliable operation of the BPA system. Mainzer *et al.*, WP-10-E-BPA-22, at 14-15. Consistent with ratemaking principles of cost causation, the significant use of balancing reserve to provide within-hour balancing of wind generation dictates the need to recover the costs associated with that use from the users of that service.

NWG does not deny that wind generators should pay for imbalance capacity. Rather, NWG argues that BPA should charge thermal and wind resources for imbalance capacity under a generally applicable imbalance capacity charge. NWG Br. Ex., TR-10-R-NG-01, at 14. As discussed in section 13.3.2.6, however, the within-hour balancing needs of thermal generators are insignificant, making a generally applicable capacity-based charge unnecessary. Mainzer *et al.*, WP-10-E-BPA-41, at 27 ("We have not separately identified a capacity charge for generation imbalance for generators other than wind, because we have not identified significant amounts of within-hour reserves that must be set aside to meet such uses of the system."). As Staff explained in direct testimony, "[o]bservations of actual operations indicated that generators other than wind are dispatchable and do not contribute to the overall reserve requirements calculated for wind and load. BPA staff will do additional analysis in the future to test this conclusion …." McManus *et al.*, WP-10-E-BPA-23, at 6-7. Thus, NWG's proposed charge does not appear to be cost-based.

NWG also argues that BPA's native load customers are not required to pay a capacity charge for within-hour reserves used to provide Energy Imbalance Service. NWG Br., TR-10-B-NG-01, at 30; NWG Br. Ex., TR-10-R-NG-01, at 15. Thus, only wind generators are required to pay an additional charge for the capacity needed to provide generation imbalance.

In fact, however, load customers do pay balancing capacity charges. Load customers must purchase Regulation and Frequency Response Service, which is based on the cost of capacity to follow load. Study and Documentation for 2010 Ancillary Service and Control Area Services, TR-10-E-BPA-03, at 7. In addition, as discussed in section 13.4.2, Issue 4, BPA's power customers pay for balancing capacity through power rates. *See also* Mainzer *et al.*, WP-10-E-BPA-41, at 27.

Accordingly, BPA finds no basis for a capacity-based charge under Generation Imbalance Service in lieu of BPA's proposed WI-10 rate. Wind generators are not similarly situated to thermal generators with regard to balancing capacity needs. Therefore, it would be inappropriate to add a capacity charge to Generation Imbalance Service.

Decision

BPA will not add a capacity charge to Generation Imbalance Service.

Issue 7

Whether BPA should retain the WI-09 Settlement rate of $0.68/kW/month for Wind Balancing Service in the FY 2010-2011 rate period or adopt a non-precedential rate of $0.75/kW/month for the FY 2010-2011 rate period.

Parties' Positions

NWG states that BPA should either 1) hold the WI-10 rate flat for the FY 2010-2011 rate period or 2) adopt a non-precedential rate of $0.75/kW/mo. for the rate period, which would represent a 10 percent increase over the WI-09 rate. NWG Br., TR-10-B-NG-01, at 42; NWG Br. Ex., TR-10-R-NG-01, at 12.

BPA Staff's Position

Staff argues that the proposed WI-10 rate is consistent with ratemaking principles and is supported by the rate proceeding record.

Evaluation of Positions

NWG urges the Administrator to either 1) hold the Wind Balancing Service rate flat for the FY 2010-2011 rate period or 2) adopt a non-precedential rate of $0.75/kW/mo. for the rate period, which would represent a 10 percent increase over the WI-09 rate. NWG Br., TR-10-B-NG-01, at 42. According to NWG, a 10 percent increase in the WI-10 rate would be consistent with the rate increase proposed for BPA's preference customers. *Id*. at 4. In its Brief on Exceptions, NWG states that its alternative WI-10 rate proposal is based on its conclusion that BPA has inflated the costs of balancing wind generation, resulting in a higher WI-10 rate. NWG Br. Ex., TR-10-R-NG-01, at 12. NWG asserts that it has provided support for its proposed WI-10 rates in the rate case record, citing its arguments regarding BPA's generation reserve forecast and pricing methodologies. *Id*. BPA addresses these arguments in ROD Chapter 13.

For several reasons, BPA disagrees with NWG's proposal. First, the adoption of either rate proposal would require BPA to ignore cost-causation ratemaking principles. BPA's proposed power rates and its Wind Balancing Service rate are based on the costs of providing the particular service. A decision simply to increase them by the same amount would be arbitrary. *See also* sections 13.3-13.4 (discussing NWG's arguments regarding BPA's generation reserve forecast and pricing methodology). NWG has not demonstrated a nexus between Wind Balancing Service and the proposed rates of either $0.68/kW/mo. or $0.75/kW/mo. As a result, NWG's proposal asks BPA to ignore cost-causation. Indeed, the fact that NWG proposes two different rates, without support based on cost causation for either one, highlights the arbitrary and uncertain nature of its proposal.

Second, an artificially lower rate would mask the true costs of wind generation. *See*, *e.g.*, Baker *et al.*, TR-10-E-JP6-1, at 8-9 ("If, in violation of cost causation, these balancing reserves costs are borne in whole or in part by other purchasers of the output of the FCRPS, the true costs of wind energy would be masked and the apparent delivered cost of wind energy would be artificially low from the perspective of the purchaser."). By adopting NWG's proposal, BPA would need to forgo its generation reserve forecast and pricing methodologies in lieu of a rate that is not cost-based. As a result, rather than allowing BPA to recover the legitimate costs associated with integrating wind generation, NWG's proposal would result in an inequitable shift of costs to the users of the Federal system that did not create those costs. *See also* section 20.1.3.1, Issue 1.

Finally, NWG's proposal would not send an appropriate cost-based price signal for use of balancing reserves, leading to overuse of such reserves. That would risk reliability problems and the potential for more curtailments under DSO 216, and push BPA closer to needing to acquire resources to provide balancing services. Such a result would lead to substantially higher rates in the future.

Decision

BPA will not adopt NWG's proposal to establish the WI-10 rate through an arbitrary 10 percent increase of the WI-09 rate and instead will establish the WI-10 rate in accordance with established ratemaking principles.

20.1.3 Legal Arguments

Parties raised various legal arguments regarding discrimination and the application of Commission policy to BPA rates. This section responds to those legal arguments.

20.1.3.1 Undue Discrimination Arguments

Issue 1

Whether BPA's proposed Wind Balancing Service rate is unduly discriminatory.

Parties' Positions

PPC *et al.* assert that BPA has taken appropriate steps in this rate case to identify and recover the costs of balancing wind generation. PPC *et al.* state that BPA has correctly applied cost-causation principles to development of the cost components and design of the rate. PPC *et al.* Br., TR-B-JP11-01, at 28-29.

In contrast, NWG argues that BPA's proposed Wind Balancing Service rate is discriminatory because it requires wind generators to pay for imbalance capacity but does not require either generators taking Generation Imbalance Service or native load customers taking Energy Imbalance Service to pay for imbalance capacity. NWG Br., TR-10-B-NG-01, at 28.

NWG also argues that BPA's proposed wind integration rate is inconsistent with section 212(i) of the Federal Power Act (FPA) and that the Commission has the discretion to make such a finding. NWG Br., TR-10-B-NG-01, at 27.

BPA Staff's Position

This is a legal issue.

Evaluation of Positions

Before BPA addresses the factual premises of the legal arguments, it is important to set forth the legal standards that apply to the review of BPA's rates.

As explained in ROD section 1.2, the legal standards that govern BPA ratemaking derive from the Flood Control Act and from BPA's organic statutes. Furthermore, Commission review of BPA's rates is limited to the three criteria specified in section 7(a)(2) of the Northwest Power Act. 16 U.S.C. § 839e(a)(2); *see* section 1.3. BPA has voluntarily filed a reciprocity tariff with the Commission and adheres to open access principles in its sale of transmission. However, Order No. 890 and related open access principles are not legally binding on BPA and do not form part of either Commission or Ninth Circuit review of BPA's rates. In addition, BPA's adherence to reciprocity principles is not an issue in this proceeding and is not relevant to the approval of BPA's rates. Finally, the statutes that govern BPA ratemaking do not include an undue discrimination standard (as discussed below, section 212(i) of the Federal Power Act, which does include such a standard, is irrelevant to this proceeding). Nevertheless, BPA will address the parties' factual contentions.

As discussed throughout this Record of Decision, the proposed rate for Wind Balancing Service is designed to capture the costs and manage the risks that are imposed on the BPA Balancing Authority Area by the variable and uncertain nature of wind energy. *See* ROD Chapter 13; Mainzer *et al.*, WP-10-E-BPA-41, at 12. BPA forecasts the amount of balancing reserve that is necessary to balance the within-hour variations of wind generation and maintain load-resource balance in BPA's Balancing Authority Area. *See* Generation Inputs Study and Study Documentation, WP-10-E-BPA-08; McManus *et al.*, WP-10-E-BPA-23, at 5; Mainzer *et al.*, WP-10-E-BPA-41, at 10 (stating that the "Generation Reserve Forecast … is robust. It has been critiqued by a broad array of internal and external stakeholders…"). As wind generation increases in BPA's Balancing Authority Area, so do the costs associated with managing the within-hour variations inherent to wind generation. Mainzer *et al.*, WP-10-E-BPA-41; Klippstein *et al.*, WP-10-E-BPA-24; Bermejo and Beale, WP-10-E-BPA-25. The rate case record contains substantial evidence in support of BPA's determination and allocation of costs.

NWG argues that BPA's WI-10 rate is discriminatory because it requires wind generators to pay for imbalance capacity, but does not require thermal generators taking Generation Imbalance Service or native load customers taking Energy Imbalance Service to pay for capacity.

PPC *et al.* point out that customers purchasing transmission to deliver power within the BPA Balancing Authority Area must purchase Regulation and Frequency Response Service from BPA; requirements customers purchasing power from BPA for their load service purchase load-following service as a component of their power service; and wind generation pays for the capacity reserves set aside for Wind Balancing Service under the WI-10 rate. PPC *et al.* Br., TR-10-B-JP11-01, at 28.

In addition, PPC *et al.* state that "BPA has correctly applied cost-causation principles to development of the cost components and design of the [WI-10] rate." PPC *et al.* Br., TR-10-B-JP11-01, at 28-29.

NWG is incorrect that the Wind Balancing Service rate is discriminatory because BPA does not charge thermal generators for imbalance capacity. In contrast to intermittent resources such as wind, thermal resources are dispatchable and do not require significant amounts of balancing reserves to balance within-hour variability. *See* section 13.4.2, Issue 4; Bermejo *et al.*, TR-10-E-BPA-10, at 21; Mainzer *et al.*, WP-10-E-BPA-41, at 27; McManus *et al.*, WP-10-E-BPA-23, at 6. As Staff testified, wind generators, because of their variability, are not similarly situated to thermal generators:

> The magnitude of wind generation has led to increasing commitments of the operational flexibility of the FCRPS to address uncertainty associated with wind generation variability and scheduling accuracy. Because the output of wind generation is subject to the variable and uncertain nature of wind speed, wind generators have difficulty predicting how much power they will generate at any given time. Wind speed can change greatly within minutes. Because most of the wind generation in BPA's [Balancing Authority Area] is located within a geographically confined area, BPA can experience swings in generation of hundreds of megawatts within a single hour. To manage these tremendous swings in wind generation (and accompanying increased variability and uncertainty) and to maintain load and resource balance, BPA must carry an increasing amount of reserve generation.

Mainzer *et al.*, WP-10-E-BPA-22, at 14.

Staff explained in rebuttal testimony: "We have not separately identified a capacity charge for generation imbalance for generators other than wind, because we have not identified significant amounts of within-hour reserves that must be set aside to meet such uses of the system." Mainzer *et al.*, WP-10-E-BPA-41, at 27; *see also* Bermejo *et al.*, TR-10-E-BPA-10, at 20-21 (explaining that the WI-10 rate is not unduly discriminatory, but is designed to capture the costs and manage risks that are being imposed on the BPA Balancing Authority by the variable and uncertain nature of wind energy).

Unlike thermal generators, load requires balancing capacity. As demonstrated in section 13.4.2., Issue 4, BPA allocates the costs of imbalance capacity to load through its power rates. The Generation Inputs Study and Study Documentation identifies the power system's reserve needs and allocates the costs of the reserves to their various uses. That study identified a significant amount of reserves that are allocated to load. *Id.*, Generation Inputs Study and Study

Documentation, WP-10-E-BPA-08, at 65, Table 3.7, lines 2 and 4. Ultimately, BPA appropriately allocates the costs to the users that create those costs based on principles of cost causation.

The bedrock principle of cost causation has long been recognized as a general ratemaking principle. *Alcoa Inc. v. FERC*, 564 F.3d 1342, 1346 (D.C. Cir. 2009) (*citing K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992)) (stating that "cost causation" traditionally requires that rates "reflect to some degree the costs actually caused by the customer who must pay them"). BPA has demonstrated that there are legitimate costs attributed to the balancing reserve requirements to manage the within-hour variability of wind. *See* section 13.4 (discussing BPA's Wind Balancing Service pricing methodology); Generation Inputs Study and Study Documentation, WP-10-E-BPA-08; McManus *et al.*, WP-10-E-BPA-23; McManus *et al.*, WP-10-E-BPA-42; Klippstein *et al.*, WP-10-E-BPA-24; Klippstein *et al.*, WP-10-E-BPA-43; Bermejo and Beale, WP-10-E-BPA-25; Bermejo and Beale, WP-10-E-BPA-44. If BPA did not allocate these costs to wind generators, the result would be an inequitable cost shift to BPA's power customers for the cost of balancing reserves used to balance wind within the hour. *See* section 13.4; *see also* Mainzer *et al.*, WP-10-E-BPA-41, at 41 ("If the reserve requirements are understated, we would allocate fewer embedded costs to generation inputs and more of the embedded costs to BPA's power customers. These costs will be recovered in the energy charges paid by power customers."); Baker *et al.*, TR-10-E-JP6-1, at 8-9 ("If, in violation of cost causation, these balancing costs are borne in whole or in part by other purchasers of the output of the FCRPS, the true costs of wind energy would be masked and the apparent delivered cost of wind energy would be artificially low from the perspective of the purchaser."). NWG has not refuted the substantial evidence in the record supporting BPA's generation reserve forecast and cost pricing methodology. *See* sections 13.3-13.4.

Finally, NWG incorrectly asserts that BPA's wind balancing rate is inconsistent with section 212(i) of the Federal Power Act and that the Commission has the discretion to make such a finding. Section 212(i) provides that under sections 210 through 213 of the Federal Power Act, the Commission has the authority to order BPA to provide transmission service, and that "[i]n applying such sections" to BPA the Commission shall ensure that

> the rates for the transmission of electric power on the [FCRTS] are governed only by … otherwise applicable provisions of law … except that no rate for the transmission of power on the [FCRTS] shall be unjust, unreasonable, or unduly discriminatory or preferential, as determined by the Commission.

16 U.S.C. § 824k(i)(B)(ii).

As the statute makes clear, the rate standard in section 212(i) applies only when the Commission is applying to BPA sections 210 through 213 of the Federal Power Act; that is, when the Commission orders BPA to provide transmission service. It does not apply to the Commission's review of BPA's rate filings under the Northwest Power Act. NWG's reliance on the Commission's review of BPA's 2002 rates for a contrary conclusion mischaracterizes the Commission's holding.

When BPA filed its 2002 rates, in addition to seeking approval of the rates under the Northwest Power Act, BPA asked the Commission to find that the rates were consistent with section 212(i). At times BPA has requested such a finding for assurance that the rates it has established for general applicability also satisfy the standard for Commission-ordered transmission. In response to BPA's request, the Commission stated that, although the Federal Power Act does not require it to make such a finding, the act also does not deny the Commission the discretion to do so. *United States Dep't of Energy--Bonneville Power Admin.*, 95 FERC ¶ 62,094, 64,135 (2001). The Commission found that the rates were consistent with the standards of section 212(i).

The Commission did not say that it had the discretion to condition approval of BPA's transmission rates under the Northwest Power Act on their consistency with section 212(i) of the Federal Power Act. Instead, it asserted the authority to make a finding not relevant to the case before it, at least when so requested.

In its Brief on Exceptions, NWG states that BPA does not deny that the Commission has the discretion to find that BPA's rates are inconsistent with section 212(i). NWG Br. Ex., TR-10-R-NG-01, at 16-17. NWG misreads both BPA's position and the statute. The Commission may make such a finding in reviewing BPA's rate filing, but may not apply that finding in this proceeding. That is, the Commission does not have the discretion to deny approval of BPA's rates because they are inconsistent with section 212(i). If the Commission found that BPA's rates were unduly discriminatory under the standards of section 212(i), that finding would apply only if a party applied to the Commission under section 211 for an order directed at BPA and the Commission issued such an order.

The Commission recognized the limited reach of section 212(i) in its review of BPA's 1993 rate filing. *United States Dep't of Energy--Bonneville Power Administration* , 67 FERC ¶ 61,351, 62,218 (1994); *order on reh'g, United States Dep't of Energy--Bonneville Power Administration*, 68 FERC ¶ 61,344, 62,389 (1994). Powerex argued that the Commission must review BPA's Northern Intertie rate under section 212(i). BPA and several other parties replied that, because the Commission had not ordered BPA to provide transmission service under section 211, section 212(i) did not apply. The Commission agreed, noting that "since [BPA's] application does not involve transmission services ordered by the Commission under section 211, the review standards under section 211 are totally inapplicable." *Id*.

Therefore, section 212(i) of the Federal Power Act is irrelevant to the decision in this rate proceeding. Even if it were relevant, the rate is not unduly discriminatory.

<u>Decision</u>

BPA's WI-10 rate is based on cost causation and is not unduly discriminatory.

20.1.3.2 <u>Consistency with Commission Policy and Precedent</u>

<u>Issue 1</u>

Whether BPA's proposed WI-10 rate is consistent with Commission policy.

Parties' Positions

MSR asserts that transmission providers must file for specific authority from the Commission if they want to supplement existing Generation Imbalance services or price existing services differently. MSR Br., TR-10-B-MS-01, at 5. According to MSR, if BPA wants to adopt the WI rate, it should be seeking authority from the Commission to vary from the standardized approach that the Commission adopted in Order 890. *Id*. at 8.

MSR also argues that the descriptions for the "within hour" wind integration rate and the generation imbalance rate seem the same. *Id*. Therefore, MSR states, BPA is charging wind generators twice for the same service. *Id*.

NWG argues that BPA's proposed WI-10 rate is inconsistent with Commission policy because BPA's rate recovers more than the costs of correcting imbalances and creates higher prices than under the Commission's *pro forma* OATT. NWG Br., TR-10-B-NG-01, at 29-30.

BPA Staff's Position

This is a legal issue.

Evaluation of Positions

Because BPA is not subject to the Commission's jurisdiction under Federal Power Act section 205, BPA has not made a section 205 filing. MSR's assertion that BPA must seek such Commission approval before proposing the WI-10 rate is incorrect. BPA also is not bound by Commission policy, though it does take it into account where appropriate.

In any case, MSR misinterprets both BPA's WI-10 rate and the Commission's *pro forma* generation imbalance service rate. As discussed in section 13.4.2, the WI-10 rate recovers BPA's capacity costs for within-hour balancing of wind generators, while the generation imbalance rate recovers BPA's energy costs for balancing of wind generators. The WI-10 rate and generation imbalance rate are not duplicative. Mainzer *et al.*, WP-10-E-BPA-41, at 19 (explaining that the Generation Imbalance charge compensates BPA only for the energy associated with imbalance and does not compensate BPA for making capacity available or any embedded costs of the system).

NWG argues that Staff's proposed rate for wind balancing is inconsistent with Commission policy because it would recover far more than actual costs. NWG Br., TR-10-B-NG-01, at 30. In addition, NWG argues that Staff's proposal is at odds with the Commission's stated policy of promoting non-discrimination in the provision of transmission service because non-wind generators as well as native load customers are not required to pay a capacity charge for within-hour reserves used to provide Generation Imbalance Service and Energy Imbalance Service, respectively. *Id*. NWG contends that there is no distinction between the within-hour reserves used for Wind Balancing, Generation Imbalance, or Energy Imbalance; therefore, there is no adequate justification for discriminating against wind generators in the provision of imbalance services. *Id*. NWG asserts that Staff's proposal to charge wind generators a capacity charge for imbalance is unjust, unreasonable, and unduly discriminatory. *Id*.

BPA's rate is cost-based. BPA charges wind generators for within-hour balancing reserve because wind generators utilize those reserves. As discussed above, BPA's power customers pay for balancing capacity through power rates. *See* section 13.4.2, Issue 4. Thus, Staff's proposal is consistent with Commission policy, because BPA allocates costs according to principles of cost causation. As the Commission recognized, some transmission providers "may need to have separate demand charges assigned to customers for the purpose of recovering the cost of holding additional reserves for meeting imbalances." Order No. 890, at 690. For public utilities, the Commission noted that "[t]o the extent a transmission provider wishes to recover costs of additional regulation reserves associated with providing imbalance service, it must do so via a separate FPA section 205 filing demonstrating that these costs were incurred correcting or accommodating a particular entity's imbalances." Order No. 890, at 690, n. 401.

NWG also states that under Order 890, imbalance charges must be consistent with three principles: 1) the charges must be based on incremental cost or some multiple thereof, 2) the charges must provide an incentive for accurate scheduling, and 3) the provisions must account for the "special circumstances presented by intermittent generators and their limited ability to precisely forecast or control generation levels, such as by waiving the more punitive charges associated with higher deviations. NWG Br., TR-10-B-NG-01, at 28-29. NWG cites the Commission's holding in *Entergy Serv., Inc.* in support of its argument that BPA has not met the Commission's test for imbalance charges. Entergy Serv., Inc, 120 FERC ¶ 61,042 (2007).

In *Entergy*, the Commission rejected Entergy's imbalance energy rate because its Deficient Energy charge was based on two tiers rather than three, and its Excess Energy charge exceeded the levels the Commission had approved in Order 890. *Id*. at 33-34. In contrast to the proposal in *Entergy*, however, BPA is not changing its energy or generation imbalance rate schedules. Wind Balancing Service is a separate service, and BPA's rate is based on the cost of providing that service. The three-factor test NWG cites above applies to generator and energy imbalance charges, and does not apply to BPA's WI-10 proposal. Therefore, even if the Commission's decision in *Entergy* were binding on BPA, it would not apply.

<u>Decision</u>

Although Commission policy does not apply to BPA rates, BPA's WI-10 rate is based on cost causation and is consistent with Commission policy.

<u>Issue 2</u>

Whether Staff's proposed Wind Balancing Service rate violates the equitable allocation standard under section 7(a)(2)(C) of the Northwest Power Act.

<u>Parties' Positions</u>

NWG argues that, because the amounts charged under the Wind Balancing Service rate serve as a credit to reduce the power rates of BPA's preference customers, the Wind Balancing Service rate disrupts the equitable allocation of the costs of BPA's transmission system between Federal and non-Federal users of the transmission system. NWG Br., TR-10-B-NG-01, at 31.

NWG also argues that the revised load assumption BPA used in the Generation Reserve Forecast violates the equitable allocation standard, because wind generators are treated differently from load. NWG Br., TR-10-B-NG-01, at 17-18.

BPA Staff's Position

This is a legal issue.

Evaluation of Positions

As discussed in ROD Chapter 13, BPA has demonstrated that its inter-business line cost allocation policy, generation reserve forecast, and pricing methodology are sound. Accordingly, BPA's WI-10 rate is based on cost causation ratemaking principles and is consistent with the Northwest Power Act's equitable allocation standard. Under that act, the Commission reviews BPA's rates to determine whether they:

(1) 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) are based on BPA's total system costs; and

(3) *as to 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) (emphasis added); *see also United States Dep't of Energy--Bonneville Power Admin.*, 39 FERC ¶ 61,078, at 61,206 (1987).

In addition to the equitable allocation standard of the Northwest Power Act, section 10 of the Transmission System Act allows uniform rates and specifies that the costs of the Federal transmission system shall be equitably allocated between Federal and non-Federal power utilizing the system. 16 U.S.C. § 838(h).

The Commission has repeatedly defined "Federal users" as "Bonneville's power customers" and "non-Federal users" as "transmission customers." *See, e.g., United States Dep't of Energy--Bonneville Power Admin.*, 122 FERC ¶ 61,143 (2008); *United States Dep't of Energy--Bonneville Power Admin.*, 112 FERC ¶ 62,258 (2005); *United States Dep't of Energy--Bonneville Power Admin.*, 95 FERC ¶ 62,094 (2001). In determining whether costs are equitably allocated between Federal and non-Federal power users, the Commission generally utilizes a reasonableness standard. The Commission has specified that BPA's rates are equitably allocated if the ratesetting "methodology follows common utility practices and reaches *reasonable results*." *United States Dep't of Energy--Bonneville Power Admin.*, 39 FERC ¶ 61,078 (1987) (emphasis added). The Commission has approved transmission rates under the Northwest Power Act's equitable allocation standard when "costs have been reasonably allocated to the two classes [Federal and non-Federal users]." *United States Dep't of Energy--Bonneville Power Admin.*, 54 FERC ¶ 61,235 (1991).

In setting transmission rates, BPA calculates the total costs of the transmission system and allocates costs to Federal power customers based on their use and to non-Federal power customers based on their use. BPA set the WI-10 rate to recover the costs associated with balancing wind generation. *See* section 13.4 (discussing BPA's pricing methodology); Bermejo *et al.*, TR-10-E-BPA-10, at 19; Study and Documentation for 2010 Ancillary Service and Control Area Services, TR-10-E-BPA-03, at 20-21. By recovering the cost of this service from the customers that use it, the WI-10 rate satisfies the Northwest Power Act's equitable allocation standard.

NWG's challenge to the "credit" to power rates misconstrues BPA's ratesetting process. Notably, NWG cites testimony filed by Cowlitz PUD, rather than testimony or a study filed by Staff, for its contention that BPA's power services receive a credit to their power rates for the cost of generation inputs. NWG Br., TR-10-B-NG-01, at 31, n.133. However, one can view the allocation of generation input costs as a credit, in that initially BPA's power customers assume responsibility for all generation costs. BPA then projects the revenue Power Services expects to receive for providing generation inputs to Transmission Services, and reduces power rates by that amount. *See* section 13.4; *see also* Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, at 1-3 and Table 1.1. Therefore, one can view the process either as allocating power costs to power customers and transmission costs to transmission customers, or as allocating all costs to power customers and then crediting these customers for costs related to transmission service.

Viewed either way, the result is the same: power costs are assigned to power customers, and transmission costs are assigned to transmission customers. Unless BPA reduced power rates by the projected revenue Power Services receives for providing generation inputs, BPA's power customers would be paying for the costs of ancillary and control area services, a transmission service, and BPA would recover those costs twice.

In its Brief on Exceptions, NWG argues that BPA ignores the crux of its argument—that to the extent that the Wind Balancing Service rate is inflated, amounts above BPA's actual costs act as a credit to BPA's Federal users of the transmission system. NWG Br. Ex., TR-10-R-NG-01, at 17. This argument is simply a repetition of NWG's argument regarding the costs BPA allocated to the Wind Balancing Service rate. BPA has amply justified its allocation of these costs. *See generally* Chapter 13.

NWG also challenges the change in Staff's revised load forecast assumptions. NWG Br., TR-10-B-NG-01, at 17. After issuing the Initial Proposal, Staff changed its load forecast assumptions, resulting in a decrease in the amount of reserves allocated to load and an increase in the amount of reserves allocated to wind. NWG argues that this change violates the equitable allocation standard, because Staff did not change its assumptions regarding wind, yet increased the reserves allocated to wind. *Id.* at 17-18.

BPA increased the reserves allocated to wind because the load and wind assumptions are not independent variables, and the change in the load assumption increased the amount of reserves BPA expects to need to support wind. Staff testified in its direct case that it would be refining its load forecast methodology to be more accurate, and that the result would be a decrease in the reserve requirement for load and an increase in the reserve requirement for wind. McManus *et al.*, WP-10-E-BPA-23, at 24-25. Although, as NWG notes, the increase in wind reserves was greater than expected, the increase itself was no surprise.

The increase occurred because of the interrelationship between load variability and wind variability. In any given hour, the variability of load can offset the variability of wind, reducing the need for reserves. The decrease in reserves needed for load reflects a decrease in the expected variability of load. Less load variability in an hour means less offset to the variability in wind, and an increased need for reserves to balance wind. To account for this relationship correctly, Staff calculates the amount of balancing reserves needed at given points in time. McManus *et al.*, WP-10-E-BPA-42, at 17. Load and wind variability are not considered in isolation. *Id.* at 20.

Consequently, the revised load assumption more accurately reflects BPA's operational practices and produces a more accurate generation reserve forecast. McManus *et al.*, WP-10-E-BPA-47, at 2-3. NWG mistakenly assumes that the revised load forecast does not affect Staff's forecast need for reserves for wind generation, and therefore reaches the mistaken conclusion that the new load forecast results in an unjustified cost shift. Since the more accurate load assumption demonstrates that BPA needs more reserves for wind generation than originally projected, the increase in the reserve needs for wind is justified. Therefore, the load assumption does not result in an inequitable allocation of costs.

Decision

BPA's proposed WI-10 rate is consistent with the equitable allocation standard of the Northwest Power Act.

20.2 Persistent Deviation for Imbalance Services

20.2.1 Introduction

BPA adopted its Intentional Deviation penalty charge for Generation and Energy Imbalance Services in 2002. In the past year, BPA observed an increasing amount of excessive and persistent schedule deviations. These deviations affect BPA's ability to maintain load and resource balance within its balancing authority area. In the Initial Proposal, Staff proposed revisions to the Intentional Deviation penalty charge provisions to clarify the penalty charge criteria that apply to intentional deviations.

In rebuttal testimony, Staff revised its proposal based on proposals made in rate case parties' direct testimony. Staff renamed the Intentional Deviation penalty charge "Persistent Deviation penalty charge" to better reflect the type of harm the penalty is designed to prevent. This section responds to the remaining issues related to Staff's proposed Persistent Deviation penalty charge for Generation and Energy Imbalance Services.

20.2.2 Issues

Issue 1

Whether the Persistent Deviation penalty charge will discourage wind development in the Northwest.

Parties' Positions

LADWP argues that imposing Persistent Deviation penalties on wind generators would chill renewable generation development, which would be in direct contradiction of the region's and the country's renewable energy goals. LADWP Br., TR-10-B-LA-01, at 16.

NWG argues that from a policy standpoint, the proposed Persistent Deviation penalty reflects an overreaction by BPA to the challenge of integrating wind. NWG Br., TR-10-B-NG-01, at 37. NWG states that BPA's unorthodox approach will discourage renewable energy development in the Pacific Northwest at a time when our country needs both clean energy and economic growth. NWG Br., TR-10-B-NG-01, at 38.

BPA Staff's Position

The proposed Persistent Deviation penalty charge, which replaces the current Intentional Deviation penalty charge, will incentivize accurate scheduling behavior. Bermejo *et al.*, TR-10-E-BPA-10, at 10. A reasonable operator can avoid the Persistent Deviation penalty charge. *Id*.

Evaluation of Positions

The evidence does not support LADWP's and NWG's broad contentions that the Persistent Deviation penalty charge will deter renewable energy development in the Northwest. BPA adopted the Intentional Deviation penalty charge in 2002, and wind generation in the Pacific Northwest has boomed. As explained in section 13.2.2, Issue 1, BPA alone has integrated approximately 2,100 MW of wind to date and expects to integrate 3,843 MW of wind into the BPA Balancing Authority Area by the end of the rate period. McManus *et al.*, WP-10-E-BPA-42, at 2 (explaining that BPA based its forecast in part on information that BPA received directly from wind developers). Even with the recent economic downturn, BPA has not seen a noticeable decrease in the amount of wind development in the Northwest. *Id*. BPA now has approximately 14,000 MW of pending wind generator interconnection requests in its Generator Interconnection Queue, and continues to receive new wind generator interconnection requests each month. McManus *et al.*, WP-10-E-BPA-42, at 3.

This dramatic growth of wind energy in the Northwest is largely attributable to Federal, state, and local renewable energy policies that have incentivized renewable energy development, such as renewable energy portfolio standards and production and investment tax credit incentives. As a result of these policies, the vast majority of wind generation currently in BPA's Balancing Authority Area is exported to satisfy the renewable energy needs of other Balancing Authority Areas. Mainzer *et al.*, WP-10-E-BPA-22, at 14. BPA expects load growth in the Pacific Northwest to further strengthen the demand for new renewable sources of generation in the region. The Persistent Deviation penalty charge is unlikely to affect this dramatic growth of renewable energy resources in the Northwest.

NWG asserts that by imposing an overly burdensome, discriminatory penalty on wind generators, Staff's unorthodox Persistent Deviation proposal would serve to discourage renewable energy development in the Pacific Northwest.

The Persistent Deviation penalty charge is avoidable, however, if the customer abides by good scheduling practices. BPA does not expect to assess this penalty often, and forecasts zero revenue from the penalty charge for the rate period. Bermejo *et al.*, TR-10-E-BPA-10, at 13. In direct testimony, Staff explained that a reasonable operator will identify and correct its schedules after observing two hours of large deviations:

> Under current scheduling practices, a customer may adjust its generation schedule (i.e., generation estimate) up to 30 minutes before the start of the next hour. This time period is known as the scheduling window. If a customer observes a large positive or negative deviation during the scheduling window, the customer has the ability to adjust its generation estimate to reduce the imbalance before the scheduling window closes for the next hour. During the second hour, if the customer is monitoring its schedules, the customer can modify its transmission schedule before the scheduling window closes for the third hour to avoid the large positive or negative deviation.

Bermejo *et al.*, TR-10-E-BPA-07, at 7. In addition, BPA is paying for installing anemometers to provide five-minute wind speed data to wind operators to make it easier for them to schedule accurately. With the availability of better wind speed data, wind generators that abide by good scheduling practices will have the ability to identify and correct large and persistent schedule deviations before the close of the scheduling window.

Indeed, Iberdrola notes that "[w]ind generators have forecasting tools available that will enable them to improve scheduling accuracy before and during the rate period." Iberdrola Br., TR-10-B-IR-01, at 12. Since wind generators, like BPA's load and thermal generator customers, have access to state-of-the-art scheduling tools, wind generators have the ability to avoid Persistent Deviation penalty charges simply by following best scheduling practices. NWG and LADWP provide no basis to support their assertion that an avoidable scheduling penalty will deter the growth of renewable resources in the Northwest.

Furthermore, BPA is including a waiver provision that will provide additional rate relief if a customer demonstrates mitigating actions taken to reduce the Persistent Deviation or extraordinary circumstances. *See* section 20.2.2, Issue 7. With the availability of a waiver, the Persistent Deviation penalty charge is unlikely to have a significant impact on customers that adopt best scheduling practices. *See also* section 20.2.3, Issue 1 (discussing the rate case parties' discrimination arguments).

Given the generators' ability to monitor and correct persistent schedule deviations, and the limited circumstances in which the Persistent Deviation penalty charge will apply, BPA is not persuaded by NWG's and LADWP's arguments that BPA's proposed penalty charge for excessive and persistent schedule deviations will have an adverse impact on the renewable energy industry. The penalty charge does not penalize customers for infrequent or insignificant schedule deviations. Further, the incentives created by Federal and state policies combined with the demand for renewable resources to serve load growth indicate that renewable energy development will continue.

Decision

Given the substantial incentives for renewable energy development, the fact that a reasonable operator can avoid the Persistent Deviation penalty charge through appropriate vigilance, and the additional data BPA is making available to wind operators, the Persistent Deviation penalty charge is unlikely to deter renewable energy development in the Northwest.

Issue 2

Whether four consecutive hours of persistent deviation is the appropriate timeframe to measure a Persistent Deviation.

Parties' Positions

Power Services and LADWP recommend that BPA should consider a four-hour standard for determining whether an Intentional Deviation (now referred to as Persistent Deviation) has occurred. Power Services Br., TR-10-B-BPS-02, at 13; LADWP Br., TR-10-B-LA-01, at 16. Both parties state, however, that, to qualify for a fourth hour, a customer must make real-time schedule changes by the third hour that addresses both the direction and trend in error.

Iberdrola and PPC *et al.* generally support a four-hour timeframe to measure a Persistent Deviation. Iberdrola Br. Ex., TR-10-R-IR-01, at 11; PPC *et al.* Br. Ex., TR-10-R-JP12-01, at 23.

BPA Staff's Position

Staff recommends that the Persistent Deviation penalty charge apply if a deviation exceeds both 15 percent of the schedule for the hour and 20 MW for four consecutive hours. Bermejo *et al.*, TR-10-E-BPA-10, at 7.

Evaluation of Positions

BPA agrees that four consecutive hours is an appropriate timeframe for the Persistent Deviation penalty. As Staff explained in direct testimony, a customer should be able to modify its schedules after observing two hours of large deviations. The customer has the opportunity to modify its schedules before the scheduling window closes for the third hour. Bermejo *et al.*, TR-10-E-BPA-07, at 7. Thus, as LADWP and Power Services suggest, the customer should be able to adjust its schedule before the start of the fourth hour.

Moreover, since customers have access to their load or generation activity data on at least a 5-minute basis, the addition of a fourth hour gives customers more than adequate time to identify and correct large and persistent deviations before the close of the scheduling window. In rebuttal testimony, Staff explained:

> Imbalance services customers receive data within each hour, at least on a 5-minute basis, reporting out load or generation activity. Specifically, PNGC receives real-time load information at the PNGC scheduling desk every 5 minutes. *See* Exhibit 1, Data Response BPA-PN-1. The access to 5-minute data allows PNGC to take significant scheduling actions before the scheduling window closes to reduce the deviation by the fourth hour. Similarly, generators have access to data continuously and can take significant scheduling action before the scheduling window closes for the fourth hour to reduce a large and persistent deviation.

Bermejo *et al.*, TR-10-E-BPA-10, at 7.

After gaining experience over this rate period, BPA will re-evaluate the appropriate minimum time to measure Persistent Deviations. *Id*. at 7.

Decision

BPA will adopt a Persistent Deviation penalty that applies after four consecutive hours of schedule deviations that exceed 15 percent of the schedule for the hour and 20 MW.

Issue 3

Whether imbalance energy errors must be in the "same direction" to constitute a Persistent Deviation.

Parties' Positions

LADWP suggests that BPA adopt Power Services recommendation that the Intentional Deviation penalty charge (now known as "Persistent Deviation") should be applied only to errors in the same direction. LADWP Br., TR-10-B-LA-01, at 16, *citing* Kitchen *et al.*, TR-10-E-BPS-02, at 7.

BPA Staff's Position

Staff states that the Persistent Deviation penalty charge should apply only if all deviations are in the same direction (*e.g.*, either four or more consecutive hours of positive deviations, or four or more consecutive hours of negative deviations, but not a mixture of positive and negative deviations). Bermejo *et al.*, TR-10-E-BPA-10, at 8.

Evaluation of Positions

BPA agrees with LADWP that in determining whether to apply a Persistent Deviation penalty charge, the schedule deviations should be in the same direction (*i.e.*, either four consecutive hours of positive deviations or four consecutive hours of negative deviations, but not a mixture of both positive and negative). *See* Bermejo *et al.*, TR-10-E-BPA-10, at 8. BPA notes that in Briefs on Exceptions, both Iberdrola and PPC *et al.* support this modification to Persistent Deviation. Iberdrola Br. Ex., TR-10-R-IR-01, at 11; PPC *et al.* Br. Ex., TR-10-R-JP12-01, at 23.

Decision

BPA will clarify that the Persistent Deviation penalty will apply only to schedule deviations of four or more consecutive hours in the same direction.

Issue 4

Whether BPA should retain the current penalty charge of 125 percent for Persistent Deviation.

Parties' Positions

Iberdrola and LADWP assert that BPA has not demonstrated that the current charge of 125 percent of BPA's highest incremental cost that occurs during the day is ineffective, or that the current charge is insufficient to deter either excessive or persistent deviations. LADWP Br., TR-10-B-LA-01, at 10; Iberdrola Br., TR-10-B-IR-01, at 19.

In its Brief on Exceptions, Iberdrola supports retention of the current penalty charge level of 125 percent. Iberdrola Br. Ex., TR-10-R-IR-01, at 11.

LADWP states that BPA's failure to impose the current penalty of 125 percent is the major if not the only reason the Intentional Deviation penalty has not provided an incentive for good scheduling behavior. LADWP Br., TR-10-B-LA-01, at 11. LADWP argues that Commission precedent makes clear that Staff's proposed 150 percent penalty charge is excessive and that it departs from the spirit of the *pro forma* OATT. *Id.* at 13.

NWG argues that BPA should not amend its existing Intentional Deviation penalty rate. NWG Br., TR-10-B-NG-01, at 43.

PNGC supports Staff's revised proposal for Persistent Deviation. According to PNGC, BPA's inclusion of the waiver provisions and retention of the penalty rate of 150 percent of BPA's highest incremental cost on that day strikes a fair balance on this issue. PNGC Br., TR-10-B-PN-01, at 2.

PPC *et al.* support a 125 percent penalty charge for Persistent Deviation. PPC *et al.* Br. Ex., TR-10-R-JP12-01, at 23.

Power Services states that the Final Proposal should remain at 125 percent and that moving to 150 percent is not warranted at this point. Miller, Oral Tr. at 8.

BPA Staff's Position

BPA's proposed increase from 125 percent of BPA's highest incremental cost of the day to 150 percent is necessary to deter large and persistent deviations. Bermejo *et al.*, TR-10-E-BPA-10, at 8-10. The 125 percent rate already applies to generation or energy imbalances within Deviation Band 3. *Id*. Reducing the charge to 125 percent would effectively eliminate the penalty. The existence of a 125 percent penalty charge did not appear sufficient to deter several excessive and persistent deviations that BPA observed in FY 2008. *Id*. *See also* Exhibit 3, Response to Data Request No. IR-BPA-1; Exhibit 4, Response to Data Request No. PN-BPA-1.

Evaluation of Positions

Staff argues that since a reasonable operator can avoid incurring the penalty charge through appropriate vigilance, a 150 percent penalty charge is reasonable under the circumstances. Given the adverse impact Persistent Deviations have on system planning, scheduling, operations, and reliability of the BPA system, Staff states that the penalty rate of 150 percent is necessary to protect against the risk of exposure to adverse reliability impacts. Bermejo *et al.*, TR-10-E-BPA-10, at 8-10.

Power Services, in contrast, asserts that a penalty charge of 125 percent is appropriate and that a 150 percent penalty does not appear to be necessary at this time. Miller, Oral Tr. at 8.

Iberdrola stated that BPA has not supported the need for a higher penalty except to explain that the standards are "fairly vague." Iberdrola Br., TR-10-B-IR-01, 19. Iberdrola stated that a penalty level of 150 percent of market should be reserved for the most egregious behaviors, but that BPA cannot show that the existing penalty level has failed to deter either egregious or intentional deviations. Iberdrola Br., TR-10-B-IR-01, at 20. At oral argument, Iberdrola explained that the penalty level is Iberdrola's primary concern with the Persistent Deviation penalty charge and encouraged BPA to set the Persistent Deviation penalty at 125 percent. Skidmore, Oral Tr. at 70. In its Brief on Exceptions, Iberdrola supports BPA's decision to retain the current penalty charge of 125 percent for Persistent Deviations. Iberdrola Br. Ex., TR-10-R-IR-01, at 11.

Similarly, PPC *et al.* support a 125 percent penalty charge for Persistent Deviations. PPC *et al.* Br. Ex., TR-10-R-JP12-01, at 23.

LADWP argues that BPA has no basis to impose a higher penalty charge, because BPA has no indication that a penalty charge of 125 percent would not provide an incentive for scheduling accuracy. LADWP Br., TR-10-B-LA-01, at 11.

BPA is persuaded by the parties' arguments that it is unnecessary at this time to increase the penalty charge for persistent deviations. Although BPA established the Intentional Deviation penalty charge of 125 percent of BPA's highest incremental cost in 2002, BPA has had difficulty applying the penalty charge because the standards are vague and could be interpreted to require a finding of intent. Miller, Oral Tr. at 7. Therefore it is correct that BPA does not have the data to determine that the current penalty rate is inadequate.

Although the proposed Persistent Deviation penalty charge serves an important function—to incentivize accurate scheduling behavior and deter persistent deviations that compromise reliable operation of the BPA system—BPA agrees with Iberdrola and LADWP that an increase in the penalty charge would be imprudent given the fact that BPA and its customers have not gained sufficient experience with the current penalty charge. Therefore, BPA will retain the current penalty charge of 125 percent of BPA's highest incremental cost that occurs during the day.

NWG recommends that BPA should not make any modifications to its existing Intentional Deviation (now called Persistent Deviation) penalty. NWG Br., TR-10-B-NG-01, at 43. BPA disagrees. The Persistent Deviation penalty charge is necessary to protect against a legitimate reliability concern. BPA is concerned about large and persistent scheduling deviations that can adversely impact planning, scheduling, operations, and ultimately the reliability of the Federal system. *See* Bermejo *et al.*, TR-10-E-BPA-10, at 14 (explaining the adverse impact of excessive and persistent schedule deviations on the BPA system). Accordingly, the rate is a necessary preventive tool against excessive and persistent schedule deviations.

Decision

BPA will retain the current penalty charge of 125 percent of BPA's highest incremental cost that occurs during that day for Persistent Deviation.

Issue 5

Whether Persistent Deviation penalties should apply in addition to Generation Imbalance Service penalties.

Parties' Positions

LADWP argues that imbalance energy penalties should not apply if BPA applies an Intentional Deviation penalty charge (now known as the "Persistent Deviation" penalty charge). LADWP Br., TR-10-B-LA-01, at 17.

BPA Staff Position

Generation Imbalance Penalties should not apply in the hours in which BPA applies a Persistent Deviation penalty charge. Bermejo *et al.*, TR-10-E-BPA-10, at 13.

Evaluation of Positions

It would be improper to charge both Persistent Deviation and Imbalance Service charges for the same hourly schedule deviation. As Staff explained in rebuttal testimony, "[a]pplying both charges would in effect penalize the customer twice for the same deviation." *Id*. Therefore, BPA agrees that Persistent Deviation penalty charges should not apply concurrently with Generation Imbalance Service charges.

However, if BPA grants a waiver of all or part of a Persistent Deviation penalty charge in any hour, the customer will remain responsible for the Generation or Energy Imbalance Service charges that BPA would have otherwise applied in those hours. In other words, a Persistent Deviation penalty charge waiver will not also act as a waiver of applicable Generation or Energy Imbalance Service charges. In their Briefs on Exceptions, both Iberdrola and PPC *et al.* support this approach. Iberdrola Br. Ex., TR-10-R-IR-01, at 12; PPC *et al*. Br. Ex., TR-10-R-JP12-01, at 23.

Decision

Generation Imbalance Service and Energy Imbalance Service charges will not apply in any hour in which BPA assesses a Persistent Deviation penalty charge.

Issue 6

Whether BPA's proposed Persistent Deviation penalty charge operates as a Deviation Band 3 penalty.

Parties' Positions

NWG argues that Staff's Persistent Deviation proposal restores the third penalty band for Generation Imbalance Service. NWG Br., TR-10-B-NG-01, at 32. According to NWG, BPA's proposed Persistent Deviation Penalty punishes wind for its natural variability. *Id*. at 33.

LADWP also argues that the Persistent Deviation charge is a Deviation Band 3 penalty in disguise. LADWP Br., TR-10-B-LA-01, at 14. LADWP argues that the charge is inconsistent with the *pro forma* OATT, since the Commission exempted intermittent resources from Deviation Band 3 penalty charges.

Iberdrola argues that BPA has failed to explain how application of the Persistent Deviation penalty to wind generators can be reconciled with Order No. 890's rejection of extreme deviation penalties for intermittent resources under Generation Imbalance Band 3. Iberdrola Br., TR-10-B-IR-01, at 23.

Power Services argues that Band 3 imbalance penalties are different from Persistent Deviation penalty charges, because Persistent Deviation penalty charges apply only after excessive and persistent deviations occur (*e.g.*, for four or more consecutive hours). Miller, Oral Tr. at 11-12.

BPA Staff's Position

The Persistent Deviation penalty charge does not reinstate Generation Imbalance Service Deviation Band 3 penalties for wind generators. Bermejo *et al.*, TR-10-E-BPA-10, at 10. Unlike Band 3, Persistent Deviation penalties apply to only a limited set of circumstances in which a reasonable operator would not allow excessive and persistent deviations to continue. *Id*. at 10.

Evaluation of Positions

BPA was first in the nation to propose and implement an exemption to Deviation Band 3 generation imbalance penalties for wind. BPA did so to promote new wind development, recognizing that there is natural variability to wind. *United States Dep't of Energy--Bonneville Power Administration*, 100 FERC ¶ 62,213 (2002). Now that BPA has tremendous growth and maturity of wind resources on its system, BPA is finding that some wind operators are taking advantage of this exemption unnecessarily to lean on the Federal hydro system. Bermejo *et al.*, TR-10-E-BPA-10, Exhibit 3. By establishing a penalty charge for extended scheduling inaccuracy, BPA hopes to retain the benefits of the original exemption while encouraging reasonable scheduling practices necessary for participants in bulk power supply markets.

NWG states that, in effect, Staff's Persistent Deviation proposal restores the third penalty band for Generation Imbalance Service, which BPA had previously removed. NWG Br., TR-10-B-NG-01, at 32-33; NWG Br. Ex., TR-10-R-NG-01, at 18. NWG argues that although BPA's Persistent Deviation penalty charge appears to apply to all customers, in reality the penalty will affect only wind generators. NWG Br., TR-10-B-NG-01, at 32-33. Thus, according to NWG, by imposing penalties that exceed the level of penalties in Deviation Band 2, BPA's proposed Persistent Deviation penalty charge acts as a Deviation Band 3 penalty. NWG Br., TR-10-B-NG-01, at 32-33; NWG Br. Ex., TR-10-R-NG-01, at 18.

BPA disagrees that the proposed Persistent Deviation penalty reinstates the Deviation Band 3 penalty under Generation Imbalance Service. Unlike Generation Imbalance Service charges, Persistent Deviation penalty charge are not incurred because of a schedule deviation for a single hour. At oral argument, BPA Power Services explained this important distinction:

> Band 3 applies to the first hour of imbalance where the natural variability of the wind can result in a schedule more or less than 7.5 percent of actual generation. And the rationale for that is still true, that variable generators shouldn't be exposed to this because they don't have enough control to meet schedules the way a thermal generator does. On the other hand, the persistent deviation will not be applied to any schedules that are off significantly in the first hour, nor will it apply if the schedule is significantly off for two hours or even three hours. But if the schedule is still significantly off in the same direction four hours after a major ramp event, that's when persistent deviation needs to apply. And it needs to apply to send a signal that this kind of behavior is unacceptable for a customer that's interconnected to the system and has an obligation to help Bonneville maintain their reliability of that system.

Miller, Oral Tr. at 11; *see also* Bermejo *et al.*, TR-10-E-BPA-10, at 11 (explaining the history of the Deviation Band 3 exemption for wind generators). The intent of the Persistent Deviation penalty is to incentivize better scheduling behavior from all customers. It is not designed to penalize the natural variability of wind generators. In addition, the trigger for the Persistent Deviation penalty charge is significantly different from the trigger for Deviation Band 3 penalties. Since the Persistent Deviation penalty does not apply unless a schedule is off in the same direction for four hours, it is not equivalent to Deviation Band 3 penalties.

LADWP states that BPA's Persistent Deviation penalty charge appears to be an end-run around the Commission's exemption for intermittent generators from Deviation Band 3 penalties in Order No. 890. LADWP Br., TR-10-B-LA-01, at 15. According to LADWP, the Commission explained that exempting intermittent resources from deviation band penalties "is consistent with the fact that intermittent generators cannot always accurately follow their schedules and that high penalties will not lessen the incentive to deviate from their schedules." *Id*. at 14-15. LADWP states that BPA's proposed Persistent Deviation penalty is inconsistent with the *pro forma* OATT; that rather than waiving the higher end of the deviation penalties for intermittent generators, it moves in the opposite direction by imposing an unduly discriminatory and excessive penalty on wind generators. Therefore, according to LADWP, any modification to the Deviation Band 3 exemption for intermittent resources must 1) be related to the cost of correcting the imbalance, 2) be tailored to encourage accurate scheduling behavior, such as by increasing the percentage of the adder as the deviations become larger, and 3) account for the special circumstances presented by intermittent generators, such as by waiving the higher ends of the deviation penalties. *Id*. at 15. LADWP asserts that BPA has not met this test for its Persistent Deviation penalty charge.

NWG states that the Commission concluded that penalties under Deviation Band 2 of the Generation Imbalance charge struck the right balance of incentives and penalties for variable resources, such as wind. NWG suggests that by imposing penalties that exceed the level of the penalties in Deviation Band 2, BPA's proposed Persistent Deviation penalty charge acts as a Deviation Band 3 penalty, which punishes wind for its natural variability. NWG Br., TR-10-B-NG-01, at 33.

Although Commission policy may inform the Administrator's decisions in this proceeding, it is not binding. As discussed in section 20.1.3.1 above, BPA has voluntarily filed a reciprocity tariff with the Commission and adheres to open access principles in its sale of transmission. However, Order No. 890 and related open access principles are not legally binding on BPA and do not form part of either Commission or Ninth Circuit review of BPA's rates. In addition, BPA's adherence to reciprocity principles is not an issue in this proceeding and is not relevant to the approval of BPA's rates.

Nevertheless, BPA does not agree that Staff's proposal is inconsistent with Commission policy. As noted above, the Persistent Deviation penalty applies only after four consecutive hours of deviations in the same direction. Therefore, Band 3 penalties will apply in many cases in which Persistent Deviation penalties do not.

In addition, unlike the case with Band 3 penalties, wind generators can avoid the Persistent Deviation penalty charge simply by monitoring and adjusting their schedules to avoid persistent and excessive schedule deviations. Wind generators in particular already have access to forecasting tools to enable improvements in scheduling accuracy to avoid persistent deviations. According to Iberdrola:

> Human input into the scheduling forecast is key in order to accurately anticipate weather behavior and its resultant impact on wind generation. Use of real-time forecasters can and will quickly close the gap between the best scheduling possible with today's technology and current scheduling techniques. Real-time forecasters will assimilate all of the meteorological observations and model outputs that are available from government, operator and vendor sources, as well as plant status data, and apply their knowledge and experience related to weather behavior and terrain to that information in order to provide the most accurate schedules possible…. The real-time forecasters provide an energy forecast to the real-time traders for each wind farm by five minutes past the tope of the scheduling hour. The real-time trader takes the forecast and schedules the project to the customer by the scheduling deadline. Once the forecasters get access to the intra-hour meteorological information from the Bonneville network … the forecasters will be able to provide forecasts at regular intervals prior to the start of the scheduling hour…. Further, it is not necessary for each wind generator to hire

> its own team of meteorologists to perform these duties – instead they can contract with other entities for these scheduling forecasting services. Accordingly, there is no reason other wind generators cannot achieve the same level of scheduling accuracy as Iberdrola Renewables.

Iberdrola Br., TR-10-B-IR-01, at 13-14. In addition, as discussed above, imbalance services customers receive load and generation data within each hour, on at least a five-minute basis. Bermejo *et al.*, TR-10-E-BPA-10, at 7. Thus, all customers can detect a persistent deviation trend before that deviation persists for four or more consecutive hours. *Id.* Notably, NWG and Iberdrola both indicate in their testimony that they believe wind generators can achieve significantly greater scheduling accuracy than they have achieved to date. *See* Dragoon, TR-10-E-NG-01, at 13-15; Froese *et al.*, TR-10-E-IR-01-CC01, at 26-30.

Power Services states the issue succinctly:

> Persistent deviations are the result of human failings, where humans managing the generators failed to respond to the natural variability by the third hour. We see that as very distinct from the Band 3 of generation imbalance.

Miller, Oral Tr. at 11. As indicated by Iberdrola, today's wind fleet has better forecasting tools at its disposal, enabling it to avoid incurring the Persistent Deviation penalty. Except for extraordinary circumstances, wind generators, like thermal generators and load, should be able to identify and correct excessive and persistent scheduling deviations. Bermejo *et al.*, TR-10-E-BPA-10, at 12.

LADWP, NWG, and Iberdrola also argue that BPA's proposed Persistent Deviation penalty charge is unduly discriminatory against wind generators. This argument is addressed in section 20.2.3 below.

<u>Decision</u>

BPA's Persistent Deviation penalty charge does not operate as a Deviation Band 3 penalty.

<u>Issue 7</u>

Whether BPA should include a waiver provision in the Persistent Deviation penalty charge that applies if the customer demonstrates mitigating actions or extraordinary circumstances.

<u>Parties' Positions</u>

Power Services asserts that the Persistent Deviation rate schedule should include a provision for waivers but that waivers should be granted only if the generator has invested in forecasting tools, demonstrates a track record of accurately forecasting ramp events, and incurs a penalty because of a "particularly unique" event or because of legitimate efforts to forecast such an event that resulted in a "false positive." Power Services Br., TR-10-B-BPS-01, at 12.

PPC *et al.* ask that BPA clarify that, if a customer requests a waiver of a Persistent Deviation penalty charge, the customer has the right to communicate with BPA, and BPA will consider evidence of the customer's attempts to mitigate the persistent deviation or evidence that demonstrates that the persistent deviation resulted from extraordinary circumstances. PPC *et al.* Br., WP-10-B-JP11-01, at 41.

BPA Staff's Position

Staff recommends that the Persistent Deviation rate include a waiver clause under which BPA will consider waiving all or part of the penalty if the customer took mitigating actions or in extraordinary circumstances. Bermejo *et al.*, TR-10-E-BPA-10, at 5.

Evaluation of Positions

BPA agrees that a waiver of all or part of a Persistent Deviation penalty charge is appropriate to provide rate relief when a customer can demonstrate mitigating actions taken to reduce the persistent deviation or extraordinary circumstances. Given the serious reliability implications of persistent deviations, however, BPA will expect the customer requesting a waiver to offer substantial evidence justifying the waiver. BPA will determine whether to grant a waiver on a non-discriminatory basis.

BPA also expects customers to make the necessary investments and improvements to avoid excessive and persistent schedule deviations. In deciding whether to grant a waiver, BPA will consider whether a customer has made significant, best efforts to improve its scheduling accuracy. For example, if a customer incurs Persistent Deviation penalties during the first year of the rate period, and does not make any quantifiable, serious investments and improvements to mitigate as best as possible persistent deviations by the second year of the rate period, BPA will be less likely to grant a waiver to that customer during the second year of the rate period.

BPA also will consider mitigating actions such as significant schedule adjustments taken during the second or third hour in an effort to prevent the deviation from continuing. These actions are quantifiable and can be verified using load or generation data. In addition, BPA will consider extraordinary circumstances, such as communications outages, as a valid reason to grant a waiver.

To address PPC *et al.*'s request, if a customer requests a waiver of all or part of any Persistent Deviation penalty charge, BPA will review the customer's request for waiver along with all evidence the customer presents. In their Briefs on Exceptions, PPC *et al.* and Iberdrola both agree with this approach. PPC *et al.* Br. Ex., TR-10-R-JP12-01, at 23; Iberdrola Br. Ex., TR-10-R-IR-01, at 12.

Finally, BPA intends to provide additional guidance for waivers in a business practice. BPA will develop the business practice protocols through its business practice notice and comment procedures.

Decision

BPA will include a waiver provision in the Persistent Deviation rate schedule.

Issue 8

Whether BPA should exempt new generation resources from the proposed Persistent Deviation penalty charge for up to 90 days while they are undergoing testing before commercial operation.

Parties' Positions

Power Services states that it is concerned about the operational impacts of a testing exemption from Persistent Deviation penalty charges. According to Power Services, exempting parties from Persistent Deviation penalties effectively gives generators in test status a free option to put unscheduled energy on the BPA system and consume the balancing reserves in a manner that has not been accounted for in the BPA-10 rate design. Power Services Br., TR-10-B-BPS-01, at 6-7.

Both PPC *et al.* and Iberdrola support Staff's proposal. PPC *et al.* Br. Ex., TR-10-R-JP12-01, at 23; Iberdrola Br. Ex., TR-10-R-IR-01, at 12.

BPA Staff's Position

An exemption from Deviation Band 3 of generation imbalance service already applies for up to 90 days for new generation resources undergoing testing before commercial operation. Staff recommends the same exemption for Persistent Deviation penalty charges. Bermejo *et al.*, TR-10-E-BPA-10, at 6.

Evaluation of Positions

Power Services states that if either a large generator or several smaller generators are testing at the same time, it could result in hundreds of megawatthours of unscheduled or inaccurately scheduled generation. Power Services Br., TR-10-B-BPS-01, at 6-7. Power Services states that this would have the same detrimental impacts on reliability and potential cost shifts as Persistent Deviations by any other loads or generation. *Id*. Power Services notes that a substantial quantity of new generation interconnections is expected in the FY 2010-2011 rate period and therefore, the potential volume of unscheduled or erroneously scheduled energy that may result from this exemption is significant. *Id*.

At oral argument, Power Services' counsel acknowledged that Transmission Services has implemented business practices that likely address Power Services' concerns, but because of *ex parte* rules, Power Services has not had an opportunity to discuss those business practices with Transmission Services. Miller, Oral Tr. at 15-16.

While acknowledging Power Services' concerns, BPA disagrees that an exemption from persistent deviation penalties for new generation resources before commercial operation during reasonable testing periods will result in a free option for injecting unscheduled energy onto the BPA system. During testing periods, BPA closely monitors the output of new generation resources, and requires testing plans and schedules of test energy. BPA currently has business practices describing the procedures that apply to BPA's current Deviation Band 3 testing period exemption under generation imbalance service. BPA intends to modify this Transmission

Services business practice to clarify the protocols that apply under the Persistent Deviation penalty charge exemption.

Moreover, since most generators prefer to begin commercial operation to sell energy in the market rather than remain in testing periods, it is unlikely that a generator will abuse or unreasonably rely upon the 90-day testing period. BPA has exempted Deviation Band 3 generation imbalance service penalties for new generation resources and has not seen any abuse of the current exemption.

Power Services recommends that the testing exemption be conditioned on the customer taking specific actions, rather than a blanket exemption. BPA agrees that a testing exemption should not be unfettered, and as described above, BPA intends to clarify in the applicable Transmission Services business practice the scheduling protocols that will apply during test energy periods.

Finally, BPA notes that both PPC *et al.* and Iberdrola support Staff's proposal. PPC *et al.* Br. Ex., TR-10-R-JP12-01, at 23; Iberdrola Br. Ex., TR-10-R-IR-01, at 12.

Decision

BPA will exempt from Persistent Deviation penalty charges new generation resources that are undergoing testing before commercial operation during reasonable test periods for up to 90 days. BPA will clarify in a business practice the protocols and requirements that apply during such test periods.

Issue 9

Whether the proposed Persistent Deviation penalty charge is overly broad and unnecessary to incentivize accurate scheduling.

Parties' Positions

Cowlitz argued that BPA's proposed new language regarding Intentional Deviation is too broad. Cowlitz Br., TR-10-B-CO-01, at 20. According to Cowlitz, the Persistent Deviation penalty language could be applied in circumstances where the deviation is not intentional, which would be inappropriate. *Id*. Cowlitz supported the alternative Persistent and Intentional Deviation approach proposed by PNGC and Iberdrola, which requires BPA to have discussions with the customer to determine if a persistent deviation is intentional before assessing a Persistent Deviation penalty charge. *Id*., *citing* Baker *et al.*, TR-10-E-PN-01, and Froese *et al.*, TR-10-E-IR-01. In its Brief on Exceptions, however, Cowlitz states that BPA's proposed modifications to the Persistent Deviation penalty charge in the Draft Record of Decision are responsive to customers' legitimate concerns. Cowlitz Br. Ex., TR-10-R-CO-01, at 3.

LADWP argues that the goal of incentivizing accurate scheduling behavior is already accomplished through BPA's charges and incentives, such as the WI-10 rate and the feathering and curtailment protocols contained in DSO 216. LADWP Br., TR-10-B-LA-01, at 8.

Similarly, NWG states that BPA has failed to demonstrate how Persistent Deviation is necessary to encourage accurate scheduling (NWG Br., TR-10-B-NG-01, at 36) and notes that wind generators are already incentivized to schedule accurately and that wind scheduling has improved without the penalty. NWG Br. Ex., TR-10-R-NG-01, at 19.

Power Services states that the Persistent Deviation charge is designed as a penalty to deter inaccurate scheduling practices and that this incentive is needed because BPA has been experiencing large and persistent deviations. Power Services Br., TR-10-B-BPS-01, at 5.

BPA Staff's Position

The Persistent Deviation penalty charge is necessary to incentivize accurate scheduling behavior in all hours and to prevent adverse reliability impacts on the Federal system. Bermejo *et al.*, TR-10-E-BPA-10, at 10.

Staff disagrees that BPA should have discussions with the customer before determining whether a persistent deviation penalty should apply. *Id*. at 5. Staff also disagrees that BPA should undertake an investigation to identify a customer's mitigating actions or extenuating circumstances before assessing a penalty charge. Staff agrees, however, that a customer may present evidence that BPA should consider when determining if a Persistent Deviation penalty charge should be waived.

Evaluation of Positions

Staff's position is that it would be administratively difficult to conduct an investigation whenever a persistent deviation occurred before applying a persistent deviation penalty charge. As Staff stated in its testimony:

> We do not agree that BPA-TS should have discussions with the customer before determining that a penalty should apply to a Persistent Deviation that meets BPA-TS's proposed criteria. Such a practice would effectively put BPA-TS in the position of the fact-finder to determine whether a Persistent Deviation is excusable in every instance, rather than put the customer in the position of justifying its persistent and excessive deviation for four consecutive hours.

Bermejo *et al.*, TR-10-E-BPA-10, at 4-5.

In its Initial Brief, Cowlitz recommended that, before assessing a Persistent Deviation penalty, BPA should have discussions with the customer to determine whether the deviation was intentional. In making this determination, BPA should be required to consider what steps the customer took to minimize deviations or to mitigate the magnitude and duration of the deviation. Cowlitz Br., TR-10-B-CO-01, at 20-21. Cowlitz stated that this two-step approach avoids mislabeling unintentional deviations as intentional deviations and minimizes the likelihood that BPA will impose above-cost penalty charges for unintentional behavior. Thus, the process of investigating and evaluating the customer's behavior will encourage customers to adopt better practices.

BPA disagrees with Cowlitz's proposal. Persistent Deviations can impair reliability regardless of intent, such as through inattention, lack of adequate investment, or other acts of negligence. Moreover, it is notoriously difficult to determine a party's intent. One of the most significant changes to the existing rate schedule that BPA has proposed is the removal of any suggestion that the penalty is based on intentional behavior. Because the penalty is no longer based on a finding of intent, discussions with customers to determine intent are unnecessary.

BPA is prepared to have discussions with the customer to determine whether a waiver should be granted. Under Cowlitz's proposal, however, BPA would need to have discussions before imposing the charge even when the facts were clear and there were no grounds for a waiver. This would result in a considerable and laborious undertaking to impose even uncontroversial penalties.

Moreover, as Staff explained, requiring discussions before assessing a Persistent Deviation penalty charge would effectively put BPA in the position of the fact-finder to determine whether a Persistent Deviation is excusable in every instance, rather than put the customer in the position of justifying its persistent and excessive deviation for four consecutive hours. Bermejo *et al.*, TR-10-E-BPA-10, at 4-5. This result would be inefficient for both BPA and its customers.

Notably, in its Brief on Exceptions Cowlitz appears to agree with BPA's rationale. Cowlitz states that BPA's proposed modifications to its Persistent Deviation penalty charge are responsive to customers' legitimate concerns.

LADWP argues that the goal of the penalty—to incentivize good scheduling behavior—is already accomplished through other charges, such as the WI-10 rate and the feathering and curtailment protocols contained in DSO 216. LADWP Br., TR-10-B-LA-01, at 8. LADWP contends that even though BPA may have charges or protocols that are not labeled as penalties, such charges and penalties are enough to incentivize the behavior sought by BPA. *Id.* at 9.

NWG also argues that wind generators are already motivated to improve scheduling to avoid Generation Imbalance charges, as well as curtailment of their output or reduction in their delivery schedules under BPA's WIT protocols. NWG Br., TR-10-B-NG-01, at 36. NWG states that BPA has failed to demonstrate that the Persistent Deviation penalty is necessary to "encourage accurate scheduling" (NWG Br., TR-10-B-NG-01, at 36) and notes that wind scheduling has improved without the penalty. In its Brief on Exceptions, NWG adds that the Persistent Deviation penalty charge is unnecessary because "wind generators will be working continually to increase scheduling accuracy to avoid feathering or curtailment orders under DSO 216." NWG Br. Ex., TR-10-R-NG-01, at 18.

In contrast, Power Services asserts that the proposed Persistent Deviation penalty is necessary to motivate parties to schedule accurately. Power Services states that the Persistent Deviation penalty is not designed to recover costs incurred because of persistent deviations, but is instead designed to prevent large deviations and consequent adverse reliability impacts to BPA's system. Power Services Br., TR-10-B-BPS-01, at 5.

In rebuttal testimony, PPC *et al.* state that "[w]ind plants have been subject to the Generation Imbalance service rate for some years, including the recent year for which BPA has quantified poor scheduling accuracy. The Generation Imbalance Service rate has not to date provided sufficient incentive to the wind plants to improve their scheduling accuracy beyond the documented level." Baker *et al.*, TR-10-E-JP6-03, at 19 (internal citation omitted). PPC *et al.* also note that

> [u]nlike thermal generation, wind generation typically receives a subsidy from the federal government in the form of a Production Tax Credit (PTC) or Investment Tax Credit (ITC). The PTC in particular is substantial, providing payment of approximately \$20/MWh of generation. Given the additional incentive to generate, it is unclear whether the potential for imposition of the Intentional Deviation penalty will be a sufficient incentive to avoid over-generation.

Baker *et al.*, TR-10-E-JP6-03, at 19.

BPA disagrees with LADWP and NWG that the WI-10 rate, Generation Imbalance service, and WIT protocols are sufficient to incentivize accurate scheduling behavior. The penalty charge for persistent deviations is necessary to deter persistent and excessive schedule deviations. The WI-10 rate is primarily designed to recover the costs associated with balancing wind rather than to incentivize good scheduling behavior. Bermejo *et al.*, TR-10-E-BPA-10, at 14. Furthermore, BPA agrees with PPC *et al.* that generation imbalance service penalties alone have been insufficient to incentivize accurate scheduling behavior. BPA had Energy and Generation Imbalance Service incentives in FY 2008; yet, BPA continued to observe large and persistent deviations. Bermejo *et al.*, TR-10-E-BPA-10, at 9. Indeed, Generation Imbalance Service charges are inherently distinct from Persistent Deviation charges. In rebuttal testimony, Staff explains:

> Generation Imbalance Service is meant to deal with differences between output and schedules that normally occur on an hour to hour basis. In contrast, Persistent Deviation is meant to deal with large and persistent deviations that a reasonable operator would not allow to continue. Since persistent and large deviations can result in reliability impacts to the BPA system, such deviations require stiffer penalties. In addition, … despite the application of Generation Imbalance Service penalties, BPA-TS continued to observe large and persistent deviations in FY 2008. *See* Exhibit 3, Data Request IR-BPA-1 and Exhibit 4, Data Response PN-BPA-1. Generation Imbalance Service alone does not appear to deter persistent and large deviations.

Bermejo *et al.*, TR-10-E-BPA-10, at 15-16; *see also* Baker *et al.*, TR-10-E-JP6-03, at 19-20 (explaining that Generation Imbalance Service charges are not solely penalties, but are intended to be energy neutral and to ensure recovery of BPA's costs of providing service given the uncertainty of the actual price of energy at the time of the imbalance).

In addition, the DSO 216 protocols apply only when BPA has exhausted 90 percent of the total balancing reserves in the BPA Balancing Authority Area and therefore are insufficient to incentivize accurate scheduling behavior in all hours. In rebuttal testimony, Staff explained the difference between the WIT protocols and BPA's proposed Persistent Deviation penalty charge:

> In contrast to the BPA Wind Integration Team ("WIT") protocols, the Persistent Deviation penalty would apply for all hours and would provide an incentive for each generator to follow good scheduling practices at all times. On the other hand, the WIT protocols apply only in extreme conditions in which 90% of BPA's balancing reserves have been exhausted. *See* Mainzer *et al.*, WP-10-E-BPA-22, at 20. The primary purpose of the WIT protocols is to preserve reliability of the BPA system under extreme conditions. If several wind generators continue to have persistent and excessive scheduling deviations, even if BPA has not exhausted 90% of its balancing reserves, the behavior of those wind generators can compromise reliability. We acknowledge that such protocols may have an effect of encouraging better scheduling; however, Persistent Deviation for Imbalance Services is still necessary to improve forecasting ad scheduling in all hours.

Bermejo *et al.*, TR-10-E-BPA-10, at 12.

NWG also states that the Persistent Deviation penalty charge is unnecessary because BPA has implied that persistent deviations are "intentional deviations." NWG argues that if some wind generators are intentionally leaning on the BPA system, BPA should enforce its existing Intentional Deviation penalty charge. NWG Br. Ex., TR-10-R-NG-01, at 19.

NWG mischaracterizes BPA's position regarding persistent deviations. As explained above, BPA does not consider persistent deviations to be intentional deviations, and has changed the name of the penalty to remove the implication that it would be imposed based on intent. Persistent deviations are likely to occur if a customer was not following best scheduling practices. This does not necessarily mean that the persistent deviation was intentional. It could be due to a lack of care. Accordingly, NWG's assertion that BPA "seeks to lower its burden of proof in order to be able to more easily assess this additional penalty on wind generators" is without merit. NWG Br. Ex., TR-10-R-NG-01, at 19.

Therefore, BPA agrees with Power Services that the persistent deviation penalty is necessary to incentivize accurate scheduling behavior. Given the real impacts that persistent deviations have on BPA's system, BPA disagrees with LADWP and NWG that BPA's current charges and incentives are sufficient to incentivize accurate scheduling behavior and prevent persistent deviations. Despite existing incentives for accurate scheduling, BPA has observed large and persistent deviations. Bermejo *et al.*, TR-10-E-BPA-10, Exhibit 3. When combined, however, the incentives produced from Generation Imbalance Service, Persistent Deviation, and BPA's proposed WIT protocols work together to incentivize better scheduling accuracy at all times under all conditions.

<u>Decision</u>

BPA will retain the Persistent Deviation penalty charge. BPA will not have discussions with customers before applying a Persistent Deviation penalty charge; however, BPA will consider a customer's request for waiver of a Persistent Deviation penalty charge.

20.3 Legal Arguments

Several rate case parties argue that BPA's Persistent Deviation penalty charge is unduly discriminatory and inconsistent with Commission policy. As stated in section 20.1.3.1 above, BPA's rates are not subject to an undue discrimination standard, and arguments regarding BPA's adherence to Commission policy that applies to public utilities are irrelevant to the adoption or approval of BPA's rates. Nevertheless, BPA will address the parties' contentions.

20.3.1.1 Undue Discrimination Arguments

Issue 1

Whether BPA's proposed Persistent Deviation penalty charge is unduly discriminatory.

Parties' Positions

LADWP argues that the Persistent Deviation penalty is intended to target wind generators and therefore imposes an unduly discriminatory penalty against them, as they unavoidably are distant from load centers and have little choice but to purchase transmission rights from BPA. LADWP Br., TR-10-B-LA-01, at 6.

Iberdrola states that the combination of rates, penalties, and reliability and operational requirements results in a structure that is unduly discriminatory toward wind generation and is in direct conflict with BPA's legal obligation under the Northwest Power Act to encourage renewable energy within the Pacific Northwest. Iberdrola Br., TR-10-B-IR-01, at 23.

NWG also argues that the Persistent Deviation penalty is discriminatory, because it would apply only to wind. NWG Br., TR-10-B-NG-01, at 32.

Evaluation of Positions

LADWP, Iberdrola, and NWG assert that the proposed Persistent Deviation penalty charge is intended to target wind generators and therefore is discriminatory. LADWP Br., TR-10-B-LA-01, at 6; Iberdrola Br., TR-10-B-IR-01, at 23; NWG Br., TR-10-B-NG-01, at 32.

Specifically, LADWP cites Power Services testimony for its contention that the Persistent Deviation penalty is intended to target wind and therefore is unduly discriminatory. LADWP Br., TR-10-B-LA-01, at 6. LADWP states that BPA's use of the Persistent Deviation penalty to motivate parties to invest in necessary scheduling and forecasting indicates BPA's intent to target wind generators. *Id.* at 8, *citing* Froese *et al.*, TR-10-E-IR-02, at 8.

BPA disagrees that the proposed Persistent Deviation penalty charge is unduly discriminatory. First, the penalty charge applies to all customers and is intended to incentivize good scheduling practices and preserve the reliability of BPA's system. Bermejo *et al.*, TR-10-E-BPA-10, at 10; *see also* Proposed 2010 Transmission and Ancillary Service Rate Schedules at 89. Far from an effort to penalize wind generators, it is a critical reliability tool.

The Power Services testimony on which LADWP relies actually supports BPA. As quoted by LADWP, Power Services testified that "[Persistent] Deviation is a critical tool that BPA must implement to encourage accurate scheduling." LADWP Br., TR-10-B-LA-01, at 6 (*quoting* Kitchen *et al.*, TR-10-E-BPS-01, at 5). LADWP's assumption that this statement refers to wind generators (which the statement does not mention) reflects LADWP's understanding that only wind generators suffer from significant scheduling inaccuracies. Hence the flaw in LADWP's argument: LADWP assumes that distinctions between customer classes are unduly discriminatory even when they are based on relevant differences between the customer classes. As the wind scheduling data indicates, wind generators experience scheduling inaccuracies that other generators do not. *See* Bermejo *et al.*, TR-10-E-BPA-10, Exhibit 3. Therefore, distinctions between the two classes of generator are reasonable and not unduly discriminatory.

In addition, LADWP omitted the rest of Power Services' statement, in which Power Services testified that the Persistent Deviation charge was also critical to "avoid operational conflicts and cost shifts in the implementation of energy imbalance and generation imbalance services." Kitchen *et al.*, TR-10-E-BPS-01, at 5. That is, unless BPA appropriately charged wind generators for the costs their scheduling deviations impose on the system, other customers would inappropriately bear these costs. Thus, far from supporting LADWP's position, Power Services testimony contradicts it.

In arguing that the Persistent Deviation charge penalizes them for wind's "natural variability," the wind generators themselves recognize that wind generation is much more variable than other generation. *See* NWG Br., TR-10-B-NG-01, at 33; Iberdrola Br., TR-10-IR-01, at 22-23. Wind generation places stresses on the transmission system that thermal generation and load do not, and the wind charges are directly related to cost causation and impacts on reliability. In rebuttal testimony, Staff explains the adverse impact of large deviations on the BPA system:

> The Persistent Deviation penalty rate is necessary to preserve system reliability and is designed to deter persistent and large scheduling deviations, which contribute to inefficient use of system resources. Based on historical data, BPA-TS has experienced persistent and large deviations. *See* Exhibit 3, Data Response IR-BPA-1 and Exhibit 4, Data Response PN-BPA-1. The larger the deviation, the more balancing reserves BPA must deploy to correct it and the larger the impact to BPA's hydro operations. Penalties for persistent and large deviations are necessary because such deviations may reduce BPA's ability to provide balancing reserves to maintain load and resource balance.
>
> Keeping the system in balance is the responsibility of BPA-TS, and BPA-TS depends on the federal hydro system to provide balancing reserves. Even if BPA does not exhaust its total reserves during an hour, a generator that produces large and persistent deviations will contribute to the operational changes the Federal hydro system must make to maintain the necessary level of reserves.

Bermejo *et al.*, TR-10-E-BPA-10, at 14.

LADWP continues, however, that BPA's analysis of customer schedules demonstrates that BPA's Persistent Deviation penalty will "very likely not apply to any generation resource other than wind." LADWP Br., TR-10-B-LA-01, at 8. The data BPA provided in Response to Data

Request No. IR-BPA-1 includes an analysis of load schedules and of wind and thermal generation schedules for October 2008 through January 2009. Bermejo *et al.*, TR-10-E-BPA-10, Exhibits 3 and 4. Because BPA initially proposed to apply the Persistent Deviation charge after three consecutive hours of schedule deviations that exceeded 15 percent of schedule and 20 MW, BPA first analyzed the penalties that would have applied under this standard. Under Staff's Initial Proposal, load, thermal generation, and wind generation customers all had persistent deviations. *Id.*, Exhibit 3.

Under Staff's revised proposal, the penalty applies only to deviations of four or more consecutive hours. As LADWP notes, at least for the four-month period BPA analyzed, under a four-hour standard only wind generators would have experienced persistent deviations. Hence, according to LADWP, the penalty is discriminatory.

The irony of this argument is that BPA relaxed the standard in response to parties' testimony (both wind generators' and others'). Iberdrola asked that the standard be five consecutive hours, Froese *et al.*, TR-10-E-IR-01, at 43, and BPA adopted a compromise position. BPA could have rejected the parties' testimony and retained the three-hour standard. In doing so BPA would have increased the likelihood that load and thermal generators would be penalized, hence removing the discrimination argument, and also ensuring that wind generators would be penalized with much greater frequency. Because BPA relaxed the standards to help wind generators, LADWP argues that the penalty discriminates against them.

Moreover, under Staff's revised proposal, not all wind generators would have had persistent deviations. Bermejo *et al.*, TR-10-E-BPA-10, Exhibit 3. Some generators are already scheduling accurately enough to avoid the penalty. Iberdrola states: "Wind generators have forecasting tools available that will enable them to improve scheduling accuracy before and during the rate period." Iberdrola Br., TR-10-B-IR-01, at 12. *See also* Dragoon, TR-10-E-NG-01, at 14 ("[T]he [wind] industry has moved swiftly to improve its scheduling accuracy…"). It is likely that those wind generators that would have been subject to the penalty in the period BPA analyzed are not following best scheduling practices. Thus, the wind generators have demanded that BPA lower its proposed wind balancing rate because scheduling accuracy has improved, while arguing that penalties for inaccurate scheduling discriminate against wind because only wind schedules attain that degree of inaccuracy. They cannot have it both ways.

In fact, all wind generators can avoid the Persistent Deviation penalty charge by monitoring their schedules and investing in the necessary scheduling tools, processes, and staff. Miller, Oral Tr. at 12-13; *see also* Iberdrola Br., TR-10-B-IR-01, at 13 ("Human input into the scheduling forecast is key in order to accurately anticipate weather behavior and its resultant impact on wind generation. Use of real-time forecasts can and will quickly close the gap between the best scheduling possible with today's technology and current scheduling techniques.")

Finally, the wind generators themselves recognize that BPA must adopt financial incentives for accurate wind scheduling. In its Initial Brief Iberdrola argued that the combination of charges and protocols that applies to wind makes BPA's wind policy discriminatory. Iberdrola Br., TR-10-B-IR-01, at 23, n. 54. In its testimony, however, Iberdrola said that scheduling accuracy was low in the past in part because "prior to the quantification of the impact of scheduling accuracy on the wind integration rate, the generation imbalance rate and penalty was the only incentive wind generators had by which to evaluate or improve scheduling accuracy." Froese *et al.*, TR-10-E-IR-01-CC01, at 27. In contradiction of its argument, therefore, in its evidentiary case Iberdrola recognized that a combination of incentives is essential.

Because the Persistent Deviation charge applies to all generators and load and is based on cost causation and impacts on reliability, it is not unduly discriminatory.

Decision

BPA's rates are not subject to an undue discrimination standard. However, BPA's proposed Persistent Deviation penalty charge is not unduly discriminatory.

20.3.1.2 Consistency with Commission Policy and Precedent

Issue 1

Whether BPA's proposed Persistent Deviation penalty charge is consistent with Commission policy and precedent.

Parties' Positions

LADWP, Iberdrola, and NWG argue that the Commission has rejected intentional deviation penalties with characteristics similar to those proposed by BPA. LADWP Br., TR-10-B-LA-01, at 12; Iberdrola Br., TR-10-B-IR-01, at 20; NWG Br., TR-10-B-NG-01, at 34-35. According to these parties, a penalty of 150 percent of the highest incremental cost that occurs during the day exceeds the penalty rates the Commission has accepted. LADWP Br., TR-10-B-LA-01, at 13; NWG Br., TR-10-B-NG-01, at 34-35; Iberdrola Br., TR-10-B-IR-01, at 22-23.

LADWP argues that the Commission rejected Entergy's proposed two-tiered approach for Deficient Energy Imbalances, finding that it would provide customers with less flexibility than required by the *pro forma* OATT, by subjecting them to the highest imbalance charge of 125 percent. LADWP Br., TR-10-B-LA-01, at 12. LADWP states that the Commission also rejected Entergy's Tier 2 and 3 imbalance charges for excess energy, ruling that both charges were higher than the charges the Commission adopted in Order No. 890. *Id.* LADWP contends that the Commission also rejected proposed penalties for deficient energy. In addition, the Commission rejected similar proposals by PJM and Avista. *Id.* Thus, LADWP asserts, Staff's proposal is inconsistent with Commission precedent, and since BPA has voluntarily filed its OATT with the Commission, BPA must demonstrate that any proposal that deviates from the *pro forma* OATT is consistent with or superior to the *pro forma* OATT provisions. LADWP Br., TR-10-B-LA-01, at 13.

Iberdrola and NWG argue that Staff's proposal is analogous to a similar proposal by PacifiCorp that the Commission rejected. Iberdrola Br., TR-10-B-IR-01, at 22; NWG Br., TR-10-B-NG-01, at 34-35. Several parties state that the Commission rejected PacifiCorp's proposal because PacifiCorp already had a three-tier imbalance band approach in place and it had not demonstrated a need for an additional penalty charge. Iberdrola Br., TR-10-B-IR-01, at 22;

NWG Br., TR-10-B-NG-01, at 35; LADWP Br., TR-10-B-LA-01, at 11-12. These parties argue that Staff's proposal is also inconsistent with the Commission's three-tier imbalance band approach.

According to Iberdrola, the Commission considers penalties for intentional deviations on a case-by-case basis, subject to a showing that they are necessary under the circumstances. Iberdrola Br., TR-10-B-IR-01, at 22. Iberdrola argues that BPA has not shown that its rate is necessary.

Iberdrola, NWG, and LADWP assert that BPA also has a three-tier imbalance charge and has not demonstrated why the increase in penalty level is necessary. Iberdrola Br., TR-10-B-IR-01, at 23; NWG Br., TR-10-B-NG-01, at 34-35; LADWP Br., TR-10-B-LA-01, at 13-14. Iberdrola asserts that, because BPA has never enforced the current penalty, it has not shown that the penalty is ineffective. Iberdrola Br., TR-10-B-IR-01, at 22.

Both LADWP and Iberdrola contend that BPA has not shown that the Persistent Deviation penalty is consistent with or superior to the OATT, and that deviations from the *pro forma* OATT must be accepted by the Commission in order for BPA to maintain reciprocity status. LADWP Br., TR-10-B-LA-01, at 13; Iberdrola Br., TR-10-B-IR-01, at 21. These parties argue that BPA's proposed Persistent Deviation penalty fails to meet the Commission's requirements for tariff deviations. *Id*.

BPA Staff's Position

This is a legal issue.

Evaluation of Positions

As a threshold matter, it should be noted that BPA's reciprocity status is not at issue in this proceeding. Even assuming that the "consistent with or superior to" standard applies to rates, BPA need not demonstrate in this case that its rate satisfies this criterion, and the Commission does not review BPA's rate filings under this standard.

Nevertheless, BPA believes that its rate does satisfy this test. First, the argument that BPA's proposed penalty of 150 percent of incremental cost violates Commission policy has been rendered moot, since BPA is now proposing a penalty rate of 125 percent.

Second, the Commission cases on which the parties rely (*PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,145 (2008), *Midwest ISO, Entergy Services., Inc.*, 120 FERC ¶ 61,042 (2007) and *Avista Corp.*, 120 FERC ¶ 61,046 (2007)) do not apply. All concern proposed Open Access Transmission Tariff deviations from the Commission's three-tiered deviation band structure for Generation and Energy Imbalance Service. BPA is not proposing a change to this structure.

For example, PJM proposed not to adopt the deviation band structure at all, a radically different issue from Staff's Persistent Deviation proposal. *PJM*, 123 FERC at 61,943. Entergy proposed a two-tier structure. *Entergy*, 120 FERC at 61,184. By contrast, BPA is proposing a separate rate, which the Commission has already approved in similar form. *United States Dep't of Energy--Bonneville Power Administration,* 95 FERC ¶ 62,094 (2001) (confirming and approving

BPA's proposed 2002 Transmission and Ancillary Services Rate Schedules, which included an Intentional Deviation penalty charge for "persistent over-generation or under-use during Light Load Hours, particularly when the customer does respond by adjusting schedules for future days to correct these patterns," among other criteria); *United States Dep't of Energy--Bonneville Power Administration*, 100 FERC ¶ 62,213 (2002); *United States Dep't of Energy--Bonneville Power Administration*, 104 FERC ¶ 62,207 (2003); *United States Dep't of Energy--Bonneville Power Administration*, 112 FERC ¶ 62,258 (2005); *United States Dep't of Energy--Bonneville Power Administration*, 122 FERC ¶ 61,143 (2008).

LADWP and Iberdrola cite *PacifiCorp*, 121 FERC ¶ 61,223, to argue that BPA has failed to demonstrate the necessity of its Persistent Deviation penalty. Staff's proposal, however, is significantly different from the proposal the Commission rejected in *PacifiCorp*.

In its Open Access Transmission Tariff filing, PacifiCorp proposed a penalty rate of 175 percent of the hourly pricing proxy as "an Intentional Imbalance penalty when a Transmission Customer deviates by 20 percent or more (or 10 MW or more) greater than its schedule for three continuous hours, or 20 percent or more (or 10 MW or more) less than its schedule for three continuous hours." *Id*. at 62,062. Staff's proposal is distinguishable in at least three crucial ways.

First, at 125 percent of incremental cost, BPA's penalty charge is significantly less than PacifiCorp's proposed charge. The Commission has already approved BPA's Tier 3 charges at this rate.

Second, BPA's Persistent Deviation penalty charge provides more time for customers to identify and correct schedule deviations. PacifiCorp's penalty applied after only three hours, if the customer's schedule was off by 20 percent *or* 10 MW. BPA's proposed charge applies after four hours, and only when the schedule is off by both 15 percent *and* 20 MW. Although BPA is proposing a standard of 15 percent instead of 20 percent, the requirement of a deviation of 20 MW for four hours makes BPA's charges less likely to apply.

Third, BPA's Persistent Deviation penalty charge is necessary to preserve reliable operation of the BPA system. Although PacifiCorp argued that its charge was necessary for system reliability, the Commission replied that "PacifiCorp has not demonstrated why the three-tier imbalance band approach … is inadequate in its circumstances to mitigate the kinds of harms PacifiCorp seeks to eliminate with its intentional imbalance penalties." *Id*. BPA has made this demonstration. As Staff and others have testified, the significant penetration of wind generation on BPA's system creates reliability issues that other systems do not experience. In addition, unlike PacifiCorp's largely thermal system, BPA's hydro system has limited flexibility because of non-power constraints (*e.g.*, Clean Water Act requirements to maintain certain levels of dissolved gas in the river, Endangered Species Act requirements) and water (*i.e.*, fuel) availability. Therefore, BPA's system requires an additional mechanism to curb excessive schedule deviations. *See* Bermejo *et al.*, TR-10-E-BPA-10, at 10 (explaining that Persistent Deviations impact BPA's ability to efficiently manage the hydro system in future hours); Kitchen *et al.*, TR-10-E-BPS-01, at 7 (explaining that non-power constraints on the FCRPS require predictability that is jeopardized by persistent deviations).

LADWP argues that the Commission declined to generically impose additional penalties such as BPA's Persistent Deviation penalty charge, and that BPA must demonstrate that its proposal for Persistent Deviation penalty charges is consistent with or superior to the Commission's *pro forma* OATT.

As noted above, BPA need not make this showing. Moreover, although the Commission declined to generically impose penalties for intentional deviations, the Commission did not preclude such penalties, instead allowing public utilities to file proposals to be considered "on a case-by-case basis, subject to a showing that they are necessary under the circumstances." *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007); FERC Stats & Regs. ¶ 31,241 at 676. The Commission has approved BPA's Intentional Deviation penalty charge in every rate case since it was established in FY 2002. *United States Dep't of Energy--Bonneville Power Administration*, 95 FERC ¶ 62,094 (2001). In this rate proceeding, BPA is simply clarifying the criteria in an existing rate schedule and has demonstrated that the charge is necessary and appropriate under the circumstances it covers. BPA has no reason to believe that this clarification does not satisfy Commission policy. It is necessary to address scheduling discrepancies in a growing wind fleet that increasingly has the capability to schedule more accurately.

Decision

BPA will retain its proposed Persistent Deviation penalty charge.

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21.0 TRANSMISSION PARTICIPANT COMMENTS

The 11 participant comments that relate to the TR-10 sub-docket all asked that small wind generators be exempted from the wind integration within-hour balancing rate. Several commenters said that they have developed or invested in small community wind projects and sell their output under the Public Utility Regulatory Policies Act of 1978 (PURPA) at avoided cost rates. They assert that under PURPA, they cannot pass on the costs of the increased wind integration rate to their customers, and that a four-fold increase in the rate—the rate proposed in BPA's Initial Proposal—would make their projects uneconomic. Several commenters state that small projects will not be developed in the region if they must absorb this increased cost.

Several participants asked that the exemption apply to wind generation projects of 10 MW or less. Others asked that the exemption apply to projects of up to 20 MW, consistent with the Commission's definition of a small generator in the Small Generator Interconnection Procedures.

21.1 Evaluation of Participant Comments

BPA recognizes that small generators often are not parties to its rate cases and that the small wind generators may not have had sufficient time to evaluate and adjust to BPA's wind integration rate proposal. As noted elsewhere in this Record of Decision, BPA also recognizes that these are difficult economic times for all parties.

On the other hand, small wind generators also contribute to the reserve needs of the balancing authority and receive wind integration service. In addition, the rate likely to result from the decisions proposed in this ROD is substantially less than the rate to which the participants were reacting when they submitted their comments. See Chapter 20 for further discussion of the rate level.

Given all these considerations, a compromise may be the best result. BPA proposes to exempt small wind generators from the wind integration rate through September 30, 2010, the first year of the rate period. This exemption gives those small wind generators that are selling their output to purchasers in other balancing authorities time to arrange telemetering of their projects to the other balancing authority. This partial exemption draws an appropriate balance between recognizing the unique needs of small projects and ensuring that all generators are allocated their appropriate share of the costs of balancing service.

The exemption will apply to wind projects of 20 MW or less. These are the projects that the Federal Energy Regulatory Commission recognizes as small generators for purposes of the Small Generator Interconnection Procedures. *See Standardization of Small Generator Interconnection Agreements and Procedures*, 111 FERC ¶ 61, 220 (2005).

In its Brief on Exceptions, WPAG argues that, by first proposing the exemption in the Draft Record of Decision, BPA short-circuited the process by which parties are normally advised of proposals and given an opportunity to respond. WPAG Br. Ex., WP-10-R-WG-01, at 23. To the contrary, BPA has followed its ratemaking procedures. Under those procedures, any person who is not a party may become a participant by submitting written recommendations for the record. *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7611 (1986), § 1010.5. In the Federal Register notice announcing the 2010-2011 rate proceeding, BPA noted that participants may submit comments "without being subject to the duties of, or having the privileges of, parties." 74 Fed. Reg. 6609, 6611 (Feb. 10, 2009). BPA added that "[p]articipants' written comments will be made part of the official record and considered by the Administrator," and established a deadline of April 24, 2009, for submission of comments. *Id*. The Hearing Officer extended the deadline to May 15, 2009. TR-10-HOO-17.

The Draft Record of Decision is BPA's first opportunity to make a proposal based on participant comments, and therefore is the method contemplated by the ratemaking procedures and the Federal Register notice. BPA followed the normal and established process for responding to participant comments, which are an established element of the rate proceeding. As WPAG has demonstrated by filing its Brief on Exceptions, it has had an opportunity to respond to the comments and to BPA's draft decision regarding what they proposed.

In the Draft Record of Decision, BPA proposed to terminate the exemption for small wind generators as of September 30, 2010. In its Brief on Exceptions, WPAG expresses skepticism that the exemption actually will terminate as of that date. WPAG Br. Ex., WP-10-R-WG-01, at 24. Similarly, PPC *et al*. and Snohomish seek assurances that the exemption is a one-time exemption that will not extend beyond FY 2010. PPC *et al*. Br. Ex., TR-10-R-JP12-01, at 25; Snohomish Br. Ex., TR-10-R-SN-01, at 8.

BPA reiterates that the exemption for small wind generators is a one-time exemption that will extend only through September 30, 2010. As to WPAG's skepticism that BPA will adhere to this decision, BPA has included in the Wind Balancing Service rate schedule both the exemption and its expiration date. Therefore, the rate that BPA is establishing pursuant to this Record of Decision already includes the automatic expiration of the exemption.

Finally, WPAG argues in its Brief on Exceptions that the exemption violates section 7(g) of the Northwest Power Act, which requires BPA to allocate costs in accordance with specific statutory provisions or equitably in accordance with generally accepted ratemaking principles. WPAG Br. Ex., WP-10-R-WG-01, at 25. This section is not as limiting as WPAG believes. The courts have repeatedly made clear that the Administrator has broad discretion in applying statutory ratemaking standards. *See* section 1.2.2. Given the unique needs of small wind generators that must compete with projects as much as 50 times their size or more, it is equitable to temporarily exempt them from the Wind Balancing Service rate to help them survive until they can make alternative arrangements. A crucial ratemaking principle is that BPA's rates are to be established to encourage the most widespread use of power at the lowest possible rates to consumers consistent with sound business principles. 16 U.S.C. § 825s. Temporarily exempting small wind generators from the Wind Balancing Service rate helps fulfill this objective while ensuring that other parties bear few if any additional costs.

PART IV

CONCLUSION

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22.0 CONCLUSION

As required by law, the rates established and adopted in this Final Record of Decision have been set to recover the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the FCRPS (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator in carrying out the requirements of the Northwest Power Act and other provisions of law. In addition, these rates have been designed to be as low as possible consistent with sound business principles, to encourage the widest possible use of BPA's power, and to satisfy BPA's other ratemaking obligations. The transmission and ancillary services rates have been designed to equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system. Finally, the Hearing Officer has assured me that all interested parties and participants were afforded the opportunity for a full and fair evidentiary hearing, as required by law.

BPA must establish its rates pursuant to section 7(i) of the Northwest Power Act. BPA must also evaluate the potential environmental impacts of the proposed rates 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 FY 2010-2011 final power and transmission rate proposals. 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 accompanying Wholesale Power Rate Schedules and Transmission Rate Schedules as final Bonneville Power Administration rates. In accordance with Federal Energy Regulatory Commission Requirements, 18 C.F.R. § 300.10(g), the Administrator hereby certifies that the Wholesale Power and Transmission Rate Schedules adopted herein are consistent with applicable laws and are the lowest possible rates consistent with sound business principles.

Issued at Portland, Oregon, this 21st day of July, 2009.

*/s/ Stephen J. Wright*_ ________________
Administrator and Chief Executive Officer

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