DRAFT RECORD OF DECISION
2008 Average System Cost Methodology

Bonneville Power Administration
U.S. Department of Energy
May 2008

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2008 Average System Cost Methodology
Administrator's Draft Record of Decision

May 2008

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COMMONLY USED ACRONYMS

AC	Alternating Current
AEP	American Electric Power Company, Inc.
AER	Actual Energy Regulation
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
Alcoa	Alcoa Inc.
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
Avista	Avista Corporation
BASC	BPA Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
C&R Discount	Conservation and Renewables Discount
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAC	Columbia Falls Aluminum Company
Cfs	Cubic feet per second
CGS	Columbia Generating Station
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
COU	Consumer Owned Utility
Con Aug	Conservation Augmentation
C/M	Consumers / Mile of Line for Low Density Discount
ConMod	Conservation Modernization Program
COSA	Cost of Service Analysis
Council	Northwest Power Planning 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
CT	Combustion Turbine
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones

DOE	Department of Energy
DOP	Debt Optimization Program
DROD	Draft Record of Decision
DSI	Direct Service Industrial Customer or Direct Service Industry
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
Energy Northwest, Inc.	Formerly Washington Public Power Supply System (Nuclear)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FERC SR	Federal Energy Regulatory Commission Special Rule
FELCC	Firm Energy Load Carrying Capability
Fifth Power Plan	Council's Fifth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GSR	Generation Supplied Reactive and Voltage Control
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
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IOU	Investor-Owned Utility

IP	Industrial Firm Power (rate)
IP TAC	Industrial Firm Power Targeted Adjustment Charge
IPC	Idaho Power Company
ISO	Independent System Operator
kAf	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LOLP	Loss of Load Probability
LRA	Load Reduction Agreement
m/kWh	Mills per kilowatt-hour
MAC	Market Access Coalition Group
MAf	Million Acre Feet
MCA	Marginal Cost Analysis
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
MT	Market Transmission (rate)
MVAr	Mega Volt Ampere Reactive
MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-coincidental Demand
NWEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFB Adjustment	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) Adjustment
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act

NPA	Northwest Power Act
NPCC	Northwest Power and Conservation Council
NPV	Net Present Value
NR	New Resource
NR (rate)	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWEC	Northwest Energy Coalition
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
OATT	Open Access Transmission Tariff
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PBL	Power Business Line
PDP	Proportional Draft Points
PF	Priority Firm Power (rate)
PFR	Power Function Review
PGE	Portland General Electric Company
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Project Act	Bonneville Project Act
PS	Power Services (formerly Power Business Line)
PSA	Power Sales Agreement
PSC	Power Sales Contract
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point Transmission
PUD	Public or People's Utility District
RAM	Rate Analysis Model (computer model)

RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
RD	Regional Dialogue
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTO	Regional Transmission Operator
SCCT	Single-Cycle Combustion Turbine
Slice	Slice of the System (product)
SME	Subject Matter Expert
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
SOS	Save Our *Wild* Salmon
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TBL	Transmission Business Line
Tcf	Trillion Cubic Feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
Tribes	Columbia River Inter-Tribal Fish Commission, Nez Perce, Yakama Nation, collectively
TS	Transmission Services (formerly Transmission Business Line)
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council (formally called WSCC)
WMG&T	Western Montana Electric Generating and Transmission Cooperative
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordination Council (now WECC)

WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
Yakama	Confederated Tribes and Bands of the Yakama Nation

1. INTRODUCTION

Bonneville Power Administration (BPA) is statutorily responsible for establishing a methodology for determining the average system cost (ASC) of resources for regional electric utilities that participate in the Residential Exchange Program (REP). Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) authorizes the REP and authorizes the BPA Administrator to determine utilities' ASCs based on a methodology developed by BPA in consultation with the Northwest Power and Conservation Council, BPA customers, and state regulatory agencies in the Pacific Northwest.. *See* 16 U.S.C. § 839c(c)(7). The ASC Methodology (ASCM) is used in the determination of monetary benefits paid by BPA to utilities participating in the REP. The existing ASCM was adopted by BPA and approved by the Federal Energy Regulatory Commission (FERC or Commission) in 1984 (1984 ASCM). *See Methodology for Sales of Electric Power to Bonneville Power Administration*, 49 Fed. Reg. 39,293, 39,297 (Oct. 5, 1984).

On August 1, 2007, the Administrator initiated a series of public meetings in which informal comment was taken on issues pertaining to the 1984 ASCM. Based in part on public comment, BPA proposed to revise the methodology by redefining the types of capital and expense items includable in ASC, establish new data sources from which ASCs are to be derived, and change the nature and timing of BPA's procedures for review of ASC filings by utilities participating in the REP. BPA announced these revisions in a Federal Register Notice (FRN) published on February 7, 2008. *See* 73 Fed. Reg. 7270 (Feb. 7, 2008). Public comment on BPA's proposal closed on May 2, 2008.

This Draft Record of Decision contains the Draft ASC Methodology and the Administrator's proposed responses to the comments received by BPA during the consultation proceeding.

2. BACKGROUND

2.1 Relevant Statutory Provisions

Section 5(c)(1) of the Northwest Power Act, 16 U.S.C. § 839c(c)(1), provides that, whenever requested, BPA must purchase certain amounts of power offered by any Pacific Northwest electric utility at the utility's average system cost of resources in each year. In exchange, BPA sells "an equivalent amount of electric power to such utility for resale to that utility's residential users within the region."[1] *Id.* The exchange was set equal to 50 percent of a participating utility's qualifying residential and small farm load as of July 1, 1980, and increased in equal annual increments to 100 percent of such load over 5 years. *See* 16 U.S.C. § 839c(c)(2). Sales to the utility may not be restricted below the amount of power acquired from the utility. 16 U.S.C. § 839c(c)(6). Under the "Residential Exchange Program", there is generally no power transferred either to or from BPA.(Section 5(c)(5) allows BPA to acquire an "equivalent amount of electric power from other sources to replace power sold to [a participating] utility," if the cost of such replacement acquisition is less than the applicable ASC. Implementation of this provision may result in actual power sales to the exchanging utility.) "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. Bonneville Power Admin.*, 928 F.2d 905, 907 (9th Cir. 1991) (*quoting Public Utility Commissioner of Oregon v. BPA*, 583 F. Supp. 752, 754 (D. Or. 1984)). The "equivalent amount of electric power" exchanged by BPA with the participating utility is priced at the same rate as that for general requirements sales to BPA's preference customers (the Priority Firm or PF rate), subject to adjustment pursuant to section 7(b)(2) of the Northwest Power Act (the PF Exchange rate). *See* 16 U.S.C. §§ 839e(b)(1)-(3).

In establishing the REP, Congress intended to address the issue of wholesale rate disparity that can exist between BPA's preference and investor-owned utility (IOU) customers. The REP is the mechanism that calculates the level of the benefits for the IOUs. *See CP Nat'l Corp*., 928 F.2d at 907 (*citing* Order No. 400-A, "Methodology For Sales of Electric Power to the Bonneville Power Administration," 30 FERC ¶ 61, 108, 61, 6195-96 (1985)). Because power sold by BPA to exchanging utilities must be treated as resold to the participating utility's residential consumers within the region, "wholesale rate parity" is achieved.

The amount paid by BPA to the participating utility is not a conventional wholesale power rate. Section 5(c)(1) of the Northwest Power Act states that BPA is to pay "the average system cost of that [exchanging] utility's resources." 16 U.S.C. § 839c(c)(1). Section 5(c)(7) of the Northwest Power Act gives BPA's Administrator the discretionary authority to determine each exchanging utility's ASC on the basis of a methodology to be established in consultation proceedings. 16 U.S.C. § 839c(c)(7). Section 5(c)(7) states:

[1] The exchange was set equal to 50 percent of a participating utility's qualifying residential and small farm load as of July 1, 1980, and increased in equal annual increments to 100 percent of such load over 5 years. *See* 16 U.S.C. § 839c(c)(2).

> The 'average system cost' for electric power sold to the Administrator under this subsection shall be determined by the Administrator on the basis of a methodology developed for this purpose in consultation with the Council, the Administrator's customers, and appropriate State regulatory bodies in the region. Such methodology shall be subject to review and approval by the Federal Energy Regulatory Commission. Such average system cost shall not include --
>
> (A) the cost of additional resources in an amount sufficient to serve any new large single load of the utility;
>
> (B) he cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after the effective date of this Act; and
>
> (C) any costs of any generating facility which is terminated prior to initial commercial operation.

The only express statutory limits on the Administrator's discretion to establish an ASC methodology are found in the above-quoted sections 5(c)(7)(A), (B) and (C) of the Act. *See* 16 U.S.C. §§ 839c(c)(7)(A), (B) and (C).

The ASC methodology established by the BPA Administrator pursuant to section 5(c)(7) of the Northwest Power Act is a "rate formula." *Public Utility Commissioner of Oregon v. BPA*, 583 F. Supp. 752, 754 (D. Or. 1984). The methodology is a BPA rule codified in Federal Energy Regulatory Commission regulations. *See Central Electric Coop. v. Bonneville Power Admin.*, 835 F.2d 199, 204 (9th Cir. 1987). Under the methodology, exchanging utilities make proposed ASC filings with BPA. BPA then reviews the filings for conformity with the ASC methodology and the requirements of section 5(c) of the Northwest Power Act. The BPA Administrator then determines the appropriate ASC for the filing utility. IOUs must also file the ASC with FERC. BPA determines the utility's REP payments are determined by comparing the utility's ASC with BPA's PF Exchange rate, and then multiplying the difference, if any, by the utility's exchangeable load. For example, if a utility had an ASC of $50/MWh and BPA's PF Exchange rate was $30/MWh, then the utility would receive REP payments equal to the difference ($20/MWh) multiplied by the utility's residential and small farm load.

Generally, the BPA PF Exchange rate has been lower than participating utilities' ASCs under the 1984 ASC Methodology. These resulting monetary benefits paid by BPA to participating utilities with a consequent, or "net cost of the exchange,". As noted above, the REP is not a conventional power transaction. System schedulers do not dispatch the exchange; line losses are not incurred. The power purchase and sale concept was created by Congress for BPA ratemaking purposes. *See* 16 U.S.C. § 839e(b)(1). The outcome of this consultation proceeding will not change the way in which BPA establishes rates under section 7 of the Northwest Power Act. The resource concept was devised by Congress to allocate the benefits and costs of the Federal Base System among competing classes of BPA customers. However, the resource concept should not obfuscate the nature of the REP as a transfer payment from BPA to the participating utilities.

Practically speaking, the purpose of the REP is to exchange costs for the benefit of the residential and small farm ratepayers of participating utilities. When the BPA PF Exchange rate is lower than a participating utility's ASC, BPA pays the net cost to that utility. However, when the PF Exchange rate is higher than the ASC, *i.e.*, when the net cost of the exchange is negative, BPA has previously provided the utility a unilateral right to "deem" its ASC equal to the PF rate, so that no payment flows from the utility to BPA. BPA does, however, keep an account of such unpaid "deemer" amounts, which must be paid before the utility can receive positive REP benefits.

Furthermore, Northwest Power Act section 5(c)(4), 16 U.S.C. § 839c(c)(4), recognizes that BPA's PF Exchange rate, insofar as it applies to the REP, may carry one or more "supplemental rate charges" after July 1, 1985, due to implementation of section 7(b)(3) of the Northwest Power Act. 16 U.S.C § 839e(b)(3). Were this to occur and cause the PF Exchange rate to exceed a participating utility's ASC, that utility has the statutory right to terminate its participation in the REP. *See* 16 U.S.C. § 839c(c)(4).

The monetary benefits of the REP must be passed through directly to the participating utilities' residential and small farm consumers in accordance with section 5(c)(3) of the Northwest Power Act, 16 U.S.C. § 839c(c)(3), guarding against the possibility that the utility might set retail residential rates that counteracted the benefits of the REP. The exchanging utilities themselves do not receive any monetary benefits whatsoever from the REP. Although exchanging utilities may seek to recover their costs of implementing the REP through their retail rates, this does not provide the utilities any benefits from the REP. In addition, it is incumbent upon BPA to establish an ASC methodology that ensures that the net cost of the exchange does not exceed the limits established by Congress in the Northwest Power Act. *See* 16 U.S.C. § 839c(c)(7)(A), (B) and (C).

The ASC methodology must also be designed so that BPA does not become the "deep pocket" to which participating utilities may shift excessive or improper resource costs. The ASCM should give participating utilities an incentive to minimize their costs. Otherwise, BPA may not be able to satisfy the requirement of section 7(a) of the Northwest Power Act that its rates recover its total revenue requirement. 16 U.S.C. § 839e(a). BPA is a self-financing government agency, which must recover its costs through rates for sales of electric power and energy. *Id*.

2.2 1981 ASC Methodology

2.2.1 Historical Background

The first ASCM was developed in the year following the signing of the Northwest Power Act into law on December 5, 1980. The 1981 ASCM was developed in consultation with interested parties through a series of working group meetings attended by representatives of IOUs, consumer-owned utilities (COUs), direct service industries (DSIs), the region's State regulatory agencies, members of the public, and BPA staff. The process began in February 1981 and continued through mid-June, when the initial proposed methodology was published. *See Proposed Average System Cost Methodology and Opportunities for Public Review and Comment*, 46 Fed. Reg. 32,727 (June 24, 1981). The goal of the consultation process was to develop an administratively feasible ASCM that would achieve the intent of the Northwest Power Act and produce equitable and technically sound results.

The participants in the 1981 consultation process represented groups with diverse interests. Each of the major groups was affected differently by the 1981 ASCM. Numerous complex financial, legal, and operating matters are involved in the process of determining utility costs. Consequently, many alternative techniques for determining ASC were identified and discussed. The consultation process did not result in a consensus on all ASC matters; however, a consensus among the participating parties was reached on the basic procedures to be used in the 1981 ASCM, as well as on numerous specific features of the methodology. Matters agreed upon for the initial proposed methodology included the jurisdictional costing approach, many cost functionalization procedures, determination of distribution losses, treatment of in-lieu taxes for COUs, and the scope of BPA's review of each utility's ASC filings.

BPA held several workshops and public meetings on the proposed 1981 ASC Methodology. A public comment forum concerning the proposed ASCM was held on July 8, 1981, at BPA headquarters, Portland, Oregon. At the opening of the hearing BPA presented an overview of the 1981 ASCM, including relevant portions of the Northwest Power Act, a summary of the consultation process, and proposed schedules and procedures. Following this presentation, members of the public were encouraged to ask clarifying questions and to present statements of their concerns. The hearing was transcribed and the transcript was reviewed in arriving at the final 1981 ASC Methodology.

The 1981 consultation process continued after the publication of BPA's initial proposed methodology, with additional working group meetings held during the public comment period. Tape recordings or detailed notes of the meetings were made part of the official record. Pacific Power & Light Company (PP&L) presented, for discussion purposes, a draft computation of ASC for PP&L in Washington State using the proposed methodology. The PP&L sample provided an opportunity to evaluate the methodology.

Major issues discussed during the public comment period were the 1981 ASCM treatment of: (1) crediting of secondary power sales and miscellaneous services revenues; (2) functionalization of revenue related taxes; (3) retroactive return of costs of construction work in progress for terminated plants; and (4) rate of return on equity for public agencies.

BPA published its final 1981 ASC Methodology on August 26, 1981, in an Administrator's Record of Decision ("1981 ASCM ROD"). That decision was based on a settlement agreement, which had resolved nearly all issues raised by parties in the consultation proceeding. On October 14, 1981, FERC granted interim approval of the 1981 ASC Methodology. *See* 46 Fed. Reg. 50,517-538 (1981)(corrected at 46 Fed. Reg. 55,952-954). Also, on October 14, 1981, the Commission convened a Joint State Board pursuant to the Northwest Power Act to obtain additional comments on the 1981 ASC Methodology from representatives of Oregon, Washington, Montana and Idaho. *See Pacific Northwest Electric Power Planning and Conservation Act-Rates for Sales to Bonneville Power Administration,* 17 FERC ¶ 61,005 (1981). Final Commission approval was received on October 17, 1983, in an order that made no substantive change to the methodology proposed by BPA. *See* 48 Fed. Reg. 46,970 (Oct.17, 1983).

2.2.2 Overview of 1981 ASC Methodology

Under the 1981 ASC Methodology, exchanging utilities filed an Appendix 1[2] with BPA "for each jurisdiction in which it desires to exchange power with BPA." *1981 ASCM ROD at 9.* Appendix 1 refers to the appendix to both the current and proposed ASCM containing the form on which exchanging utilities report their Contract System Costs and other information required for the calculation of ASC. The information in the utility Appendix 1 filings was based on filings with or rate orders from state public utility commissions. The 1981 ASCM required an exchanging utilities to file an Appendix 1 with BPA "each time it files for a jurisdictional rate change or otherwise commences a rate change proceeding" *Id.* and each time a utility receives "either an interim or final approval of the rate proposal." *Id.* This resulted in exchanging utilities being required to file at least two and sometimes three ASC filings exchanging utilities were required to file during the course of a retail rate proceeding in each jurisdiction they served that was eligible for REP benefits. This filing requirement placed an administrative burden on filing utilities and on BPA, which sometimes had 20 filings under review simultaneously. Between August 1981 and October 6, 1983, when FERC issued Order No. 337 approving BPA's 1981 ASCM, BPA had reviewed and submitted 63 ASC filings with FERC for review and approval. Docket No. RM81-41-000 Order No. 337, Page 8. The 1981 ASCM used a jurisdictional costing approach, relying on rate orders from state utility commissions as the starting point for costs included in an Appendix 1 filing. BPA did not have a defined period of time in which to review a utility's ASC filing under the 1981 ASC Methodology, which required only that BPA's review "be as prompt as possible." *1981 ASCM ROD, page 9*

The 1981 ASCM allowed IOUs to include return on equity and income taxes as allowed by their state regulatory commissions. The 1981 ASCM ROD did not identify and discuss inclusion of return on equity and income taxes in IOUs' ASC filings because the participants in the development of the 1981 ASC Methodology were largely in agreement that as components of jurisdictionally approved costs, return on equity and income taxes should be included in a utility's ASC filing. "Agreement has been reached by the consulting parties that the costs allowed or established for retail ratemaking purposes should be used in calculating ASC, subject to certain specific requirements." *Id. at 11.* All transmission plant was allowed in ASC filings under the 1981 ASC Methodology, subject to the definitions of Transmission and Distribution contained in Footnotes 7 and 8 of the 1981 ASCM.

2.3 1984 ASC Methodology

2.3.1 Historical Background

As noted above, the 1981 ASCM relied primarily upon state utility commission orders as the source of data to calculate the IOUs' ASCs. Reliance on state regulatory agencies to determine the level of costs included in the ASC of a participating utility, also known as the "jurisdictional costing approach," caused several administrative problems for BPA. Routinely, the orders of regulatory agencies did not

[2] Appendix 1 refers to the appendix to the ASC Methodologies containing the form on which exchanging utilities report their Contract System Costs and other information required for the calculation of ASC.

contain the specific numbers necessary for ASC computation. In such instances, values for ASC accounts had to be imputed.

Another drawback to the jurisdictional approach was that state rate regulators were not responsible for enforcing the requirements of the Northwest Power Act section 5(c). Instead, they are charged by state law or local ordinance with setting reasonable rates that maintain the financial health and stability of the regulated utility. The interests of utility ratepayers and shareholders are commonly viewed as antagonistic. The courts have accorded regulators the latitude of a "zone of reasonableness" in which to set rate that balance these interests. *Federal Power Commission v. Natural Gas Pipeline Company*, 317 U.S. 575, 585 (1942). However, the choice of rates within this zone was undoubtedly affected by BPA's obligation under the 1981 ASCM to provide whatever benefit payments a retail rate order dictated.

With benefits from BPA in the picture, higher retail rates did not necessarily produce higher bills for residential ratepayers. This phenomenon favored the establishment of retail rates at the upper end of the zone. As such, a participating utility might not be given an adequate incentive to control its costs. Yet, BPA could not intervene and participate in every regional rate proceeding to protect the interests of its own customers and its ability to recover its revenue requirement. Also, BPA did not want to influence the ratemaker because the purpose of the action taken by both parties were different.

There had also been instances when serious concern had been raised that costs approved for retail ratemaking purposes, and thus added to the REP benefits under the 1981 ASC Methodology, had included terminated plant costs prohibited under section 5(c)(7)(C) of the Northwest Power Act. In one case, terminated plant costs were removed from an ASC filing during BPA review. *See* BPA's Average System Cost Report for Portland General Electric Company, Jurisdiction: Oregon (May 13, 1983). In another case, terminated plant issues were debated but became moot when another adjustment was made by BPA to an ASC filing. *See* Average System Cost Report for Pacific Power & Light Company, Jurisdiction: Oregon (November 2, 1983).

Terminated plant issues, in particular, caused all of BPA's DSI customers to request a change in the 1981 ASCM by invoking Section VI of the Methodology. BPA's public agency customers also requested a new consultation proceeding.

The proceeding leading up to the 1984 ASCM had its antecedents in a BPA review of an ASC filing by Pacific Power & Light Company (PP&L) where it had been alleged that terminated power plant costs had been unlawfully included. After analyzing the available evidence on the issue, BPA concluded that it could not specifically identify any such costs in the filing. Probative data were not available to establish precisely what the Oregon Public Utility Commissioner had ruled in its rate order. In the BPA report on PP&L's ASC filing, dated December 27, 1982, BPA noted that:

> BPA has an express duty to comply with Section 5(c)(7)(C) of the Regional Act. This section requires BPA to exclude from Average System Cost any costs of generation facilities that are terminated prior to date of commercial operation. Our review did not identify cost associated with terminated plant in PP&L's rate base, cost of capital, expenses, or the effect of such costs on PP&L'S filed Average System Cost. However,

> we have concerns. The present Average System Cost Methodology is designed in such a way that the cost of capital, return on equity, and extraordinary gains and losses could conceal terminated plant costs. We think it would be appropriate to revise the Average System Cost Methodology to demonstrate clearly that the requirements of Section 5(c)(7)(C) (16 U.S.C. §839c(c)(7)(C)) are being met. BPA plans to initiate a consultation process to revise the Average System Cost Methodology.

ASC Report of December 27, 1982, at 1, FERC Docket No. ER83-266-000.

In response to certain customer requests, on October 7, 1983, BPA initiated the 1984 ASCM consultation proceeding by publishing a "Request for Recommendations" in the *Federal Register*. 48 Fed. Reg. 45829 (October 7, 1983). This notice listed 17 issues for comment and encouraged additional comments on issues related to the development of a reformed ASC Methodology. Responses were received by November 7, 1984.

On February 3, 1984, after reviewing the comments received in response to BPA's earlier *Federal Register* notice, BPA published a "Proposed Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange." 49 Fed. Reg. 4230 (February 3, 1984). This notice provided for the filing of comments on the proposal until March 15, 1984, with reply comments due April 9, 1984. These dates were later extended by BPA to March 19 and April 13, 1984, respectively, at the request of BPA's IOU customers. Extensive written comments and reply comments were filed by all interested parties.

On May 15, 1984, following review of the record compiled at that time, BPA staff released a new proposed 1984 ASC Methodology. The staff proposal summarized the consultation proceeding, the proposal negotiated by interested parties, and a possible phase-in of the new methodology in order to minimize the effect of a methodological change on the retail ratepayers of exchanging utilities. BPA issued the final Record of Decision for the 1984 ASC Methodology on June 4, 1984 ("1984 ASCM ROD"). FERC subsequently granted interim approval of the methodology on June 12, 1984 (49 Fed. Reg. 24,146 (June 12, 1984)) and final approval on October 5, 1984 (49 Fed. Reg. 39,293 (Oct. 5, 1984)).

2.3.2 Overview of the 1984 ASC Methodology

Under the 1984 ASC Methodology, utilities file with BPA "Appendix 1" forms containing cost information based on rate orders from state utility commissions or consumer-owned utility governing bodies. BPA reviews each Appendix 1 for conformance with criteria specified in the Methodology. *See* 18 C.F.R. § 301.1. Appendix 1 filings are subject to review for 210 days from the start of the relevant exchange period, which is triggered by a change in retail rates. Not later than 80 days after a Utility files a new Appendix 1, Regional Power Sales Customers or their designee may submit written challenges to costs included in the Utility's Contract System Costs. Not later than 90 days following the date the Utility files its revised Appendix 1, BPA mails to the Utility and all parties a list of issues or challenged costs concerning the Utility's revised Appendix 1 and requesting comments from all parties. Written comments on the issues list from all parties are due 30 days after the issue list is filed. Parties may submit cross-comments in response to comments on the issues list up to 15 days after the written comments are submitted. Parties may request oral argument before the Administrator or the Administrator's designee up to 150 days after a Utility files a new Appendix 1. BPA also has the right under the 1984 ASC Methodology to issue a notice to parties requesting comments on costs that had not been challenged previously, on Contract System Loads, and other issues not raised previously. Comments from parties on such notice are due 150 days after a Utility files a new Appendix 1. Written cross-comments in response to comments on the BPA notice are due 165 days after a Utility files a new Appendix 1.

If BPA grants a request for oral argument, such argument is presented up to 180 days after a Utility files a new Appendix 1. BPA must issue a final determination on the revised Appendix 1 no later than 210 days after a Utility files a new Appendix 1.

Discovery is another component of the 1984 ASCM. BPA can request data from a Utility any time during the 210-day review period. The Utility is required to respond within 30 days of receiving the data request. In addition, parties to the ASC review can submit data requests up to 40 days after the Utility files its revised Appendix 1. The Utility must respond within 65 days after the Utility files its revised Appendix 1.

Consumer-owned utilities may execute Residential Purchase and Sale Agreements (RPSAs) for participation in the REP. Because consumer-owned utilities are not regulated by the state commissions in the Pacific Northwest, preparation and review of ASC filings is more burdensome for all parties concerned. The difficulty in the preparation and review of ASC filings was a major cause of disputes between BPA and participating consumer-owned utilities and became one of the issues leading BPA and the consumer-owned utilities to settle out their REP participation in the late 1980s.

2.3.3 Differences Between 1981 and 1984 ASC Methodologies

The 1984 ASC methodology made several significant changes to the 1981 ASC methodology; one was development of a formal ASC review process establishing a 210-day timeline for review of utility ASC filings, described in the above section. Another limitated transmission plant to what was in service as of July 1, 1984, plus the cost of new transmission plant placed in service after July 1, 1984, if it is used to integrate generation resources into the exchanging utility's grid, or the sum of new transmission plant that is used to connect the resource to BPA's grid plus wheeling costs to get the power across BPA's system to the exchanging utility's grid. Return on equity was also removed from the determination of an exchanging utility's ASC largely because of concerns that state commissions used return on equity to compensate a utility for the costs associated with terminated plants. The Northwest Power Act prohibits the inclusion of terminated plant costs in utility ASC filings. Finally, Federal income taxes were also excluded from the calculation of an exchanging utility's ASC.

2.3.4 Legal History of 1984 ASC Methodology

The IOUs and state commissions vigorously opposed the 1984 ASC Methodology. They filed several lawsuits that attempted to enjoin or otherwise prohibit BPA's creation and implementation of the 1984

ASC Methodology. *See Pacific Power & Light Co., v. BPA*, 589 F.Supp. 539, 543-44 (D. Or. 1984), *aff'd* 795 F.2d 810 (9th Cir. 1986); *see also Public Utility Comm'r of Oregon v. BPA,* 583 F.Supp. 752 (D.Or. 1984) *aff'd*, 767 F.2d 622 (9th Cir. 1985)*; Public Utility Comm'r of Oregon v. BPA,* 767 F.2d 622 (9th Cir. 1985).

The first substantive challenges to the 1984 ASC Methodology were raised at FERC after BPA filed the final methodology with the Commission on June 4, 1984. *See* 49 Fed. Reg. 24,146 (June 12, 1984). In particular, the IOUs and state commissions opposed BPA's decision in the 1984 ASC Methodology to eliminate income taxes from ASC calculations and to use the embedded cost of long-term debt instead of return on equity as a cost factor. The net result of these changes was to substantially reduce the amount of benefits BPA pays to the IOUs under the REP.

FERC approved the 1984 ASC Methodology, finding that BPA had discretion to include or exclude taxes and return on equity. *See Methodology for Sales of Electric Power to Bonneville Power Administration*, 49 Fed. Reg. 39,293, 39,297 (Oct. 5, 1984). Though deferring to BPA's judgment, the Commission made known its "reservations from a ratemaking perspective" with some of the provisions of the Methodology. *Id.* at 32,296. The Commission noted that long-term debt costs are almost always lower than equity costs and may not be entirely appropriate as proxies for the cost of equity, as BPA suggested. *Id.* at 32,297. The Commission also had difficulty understanding how BPA could allow a proxy for return on equity while disallowing all taxes on such profits. *Id.* In the end, the Commission could "perceive[] no discernible contravention of the letter or spirit of the NPA … [and] is therefore approving the methodology." *Id.*

Eight IOUs and four state regulatory agencies subsequently filed petitions with the United States Court of Appeals for the Ninth Circuit challenging FERC's final approval of the 1984 ASC Methodology. *See PacifiCorp v. FERC*, 795 F.2d 816 (9th Cir. 1986). In *PacifiCorp*, the Court affirmed FERC's approval and BPA's decision to adopt the 1984 ASC Methodology, including the decisions to exclude taxes and return on equity from ASC. *Id.* However, in sustaining BPA's position, the Court noted that it did not "sanction" a permanent exclusion of equity and taxes from the ASC determinations. *Id.* at 823. Specifically, the Court stated:

> In upholding BPA's ASC determinations in this case, however, we do not sanction any permanent implementation of these exclusions. We uphold the exclusions in this instance because we conclude that we must defer to BPA's view that the statute authorizes such adjustments in ASC in response to BPA's experience with the program and the need to avoid abuses. The record in this case reflects that this is such a situation. The statute itself, however, neither commands nor proscribes these adjustments in ASC methodology.

Id.

The Court deferred to BPA's interpretation because of BPA's experience with the 1981 ASC Methodology and its need to avoid abuses. As the above quoted text makes clear, the Northwest Power Act, however, "neither commands nor proscribes these adjustments in the ASC methodology." *Id.*

2.4 Implementation of the 1984 ASC Methodology (1984-1996)

The reliance on state regulatory agencies to determine the level of costs included in the ASC of a participating Utility under the 1984 ASC Methodology was known as the "jurisdictional costing approach." This approach resulted in a long, burdensome, expensive and often contentious review process. The 210-day review period for each ASC filing under the 1984 ASC Methodology meant that BPA and its customers were almost always reviewing an ASC filing. This burden was further compounded due to the volume of utility rate orders. Because any commission-ordered change in retail rates triggers a new ASC filing under the 1984 ASC Methodology, BPA and its customers could be faced with requirements to review several ASC filings a year for each investor-owned utility participating in the REP because of adjustment clauses and tracker filings in each state where the Utility provides retail electric service to customers.

As noted above, BPA's ASC determinations under the 1984 ASC Methodology were contentious. This derived in part from the IOUs' objections to the implementation of the 1984 ASC Methodology, which they continued to view as seriously flawed. Dozens of BPA's ASC determinations were contested before FERC. Some REP disputes were resolved by the Ninth Circuit Court of Appeals. The Energy and Water Development Appropriations Act, P.L. 104-46, provided, among other things, that BPA would pay $145 million in benefits for FY 1997 to utilities participating in the REP. In addition, due to the burdensome, expensive and often contentious nature of implementing the 1984 ASC Methodology, BPA worked with exchanging utilities to develop REP settlement agreements, which resolved disputed REP issues through the remaining terms of the utilities' RPSAs. Five of the six exchanging IOUs had executed REP settlement agreements by 1998, which settled REP disputes through June 30, 2001. BPA also entered into several REP settlement agreements with exchanging consumer-owned utilities, with some settlements established in the late 1980s. As a result of the REP benefits established for FY 1997 and settlements with exchanging utilities, BPA did not conduct the REP other then making payments under the Settlement Agreements from 1996 to 2001.

2.5 BPA's Power Subscription Strategy and Residential Exchange Program Settlement Agreements

2.5.1 The Comprehensive Review of the Northwest Energy System

In early 1996, the governors of Idaho, Montana, Oregon and Washington convened the Comprehensive Review of the Northwest Energy System. The goal of the review was to develop recommendations for changes in the region's electric utility industry, focusing on BPA, through an open public process involving a broad cross-section of regional interests. In December 1996, after over a year of intense study, the Comprehensive Review Steering Committee released its Final Report.

The Final Report summarized the Steering Committee's goals and proposals. The Final Report proposed a subscription system for purchasing specified amounts of power from BPA at cost with incentives for customers to take longer-term subscriptions ("Subscription"). In connection with its Subscription proposal, the Steering Committee encouraged BPA and other parties in the region to explore a settlement of REP disputes with the region's IOUs.

2.5.2 BPA's Power Subscription Strategy

Consistent with the recommendations of the four state governors to develop Subscription by joining with the Pacific Northwest Utilities Conference Committee, BPA in early 1997 invited 2,800 interested parties throughout the Pacific Northwest to help further define Subscription. Over the next 18 months, BPA, its customers and other interested parties discussed and clarified many Subscription issues. BPA sought input from a wide range of interested and affected groups and individuals. BPA collaborated with Northwest Tribes, public interest groups, Congressional members, the Department of Energy ("DOE"), the Administration, and BPA's customers to resolve issues, understand commercial interests, and develop strong business relationships. With input from these groups and the public, BPA confirmed its goals, defined issues, developed an implementation process for pursuing the Subscription plan, and developed proposed BPA product and pricing principles. BPA also proposed to develop a Power Subscription Strategy ("Subscription Strategy").

BPA's Subscription Strategy was a comprehensive BPA business plan that planned many details regarding service for all of BPA's customer classes: preference customers, IOUs, and DSIs. With regard to the IOUs, the Subscription Strategy proposed that BPA would offer the ability to (1) continue participation in the REP through RPSAs or (2) enter into negotiated settlement agreements of the REP for the FY 2002-2011 period. The proposed settlement of REP disputes would provide benefits in settlement of, and in return for, a waiver of claims under the REP. Under the Subscription Strategy, the REP Settlement Agreement benefits were to be in the form of monetary payments or the sale of power, or both. As opposed to the approximately 4500 aMW of IOU loads potentially eligible for REP benefits, residential and small farm loads of the IOUs would, under the proposed settlement, be assured access to the equivalent of only 1900 aMW of BPA power benefits for the FY 2002-2006 period and 2200 aMW of BPA power benefits for the FY 2007-2011 period. At least 1000 aMW during the first five years, FY 2002-FY 2006, were to be met with actual BPA power deliveries. Any monetary payment would reflect the difference between the market price of power forecasted in BPA's rate case, and an amount expected to be approximately equal to the PF Preference rate. The Subscription Strategy noted that BPA would set the relative proportions of the power delivery and monetary payment components of the settlement amount in the 2000 REP Settlement Agreements. At the conclusion of this public process, BPA published its final Subscription Strategy and Record of Decision ("ROD") on December 21, 1998. *See* Subscription Strategy, Administrator's ROD ("Subscription ROD").

2.5.3 Power Subscription Strategy Supplemental ROD

Following the adoption of BPA's Subscription Strategy and ROD, BPA undertook an additional public comment process seeking input on the amount and allocation of power and financial benefits to be provided the lOUs on behalf of their residential and small farm consumers under the proposed REP Settlement Agreements. This public process would result in BPA's eventual adoption of a Supplemental Subscription Strategy and ROD ("Supplemental ROD"). BPA decided to increase the amount of settlement benefits from 1800 aMW to 1900 aMW for FY 2002-2006. Virtually all commenters supported the benefit allocation recommended by the Commissions and proposed by BPA. BPA's allocation received support from diverse customer and interest groups: publicly owned utilities, IOUs, the state regulatory commissions, state agencies, and a city commission.

2.5.4 <u>2000 REP Settlement Agreements and RPSAs</u>

After completion of the Administrator's Supplemental Subscription Strategy and ROD, BPA began to develop prototypes of two agreements: (i) a Residential Purchase and Sale Agreement ("2000 RPSA") and (ii) an REP Settlement Agreement ("2000 REP Settlement Agreement"). Developing both agreements was necessary because although BPA fully expected the IOUs to sign the Settlement Agreements, BPA also had an obligation to offer an RPSA. If any IOU chose to return to the traditional REP, BPA and the IOU would need to execute an RPSA to implement the program.

BPA requested comments on both the prototype RPSAs and REP Settlement Agreements. During this comment process, several of the IOUs requested that BPA not use its 1984 ASC Methodology to determine ASCs under the RPSAs. *See* Residential Purchase and Sale Agreements with Pacific Northwest Investor-Owned Utilities, Administrator's ROD, October 4, 2000, at 11. Instead, the IOUs requested that BPA immediately begin a reconsultation process to revise the ASC Methodology. *Id.* BPA decided not to formally commence the process of adjusting the ASC Methodology, but agreed to "informally discuss possible revisions." *Id.* at 24.

The need to have these informal discussions on revising the 1984 ASC Methodology, however, diminished as more and more of the IOUs decided to execute the REP Settlement Agreements. By the end of October of 2000, all of the IOUs had elected to sign the REP Settlement Agreements. Because the primary beneficiaries of the REP had agreed to the REP Settlement Agreements, BPA did not hold any further discussions on revising the 1984 ASC Methodology.

2.5.5 <u>Portland General Elec. Co. and Golden NW Aluminum Decisions</u>

Though there was broad customer support for the REP Settlement Agreements, several customers challenged BPA's decision to execute the REP Settlement Agreements in the Ninth Circuit. A number of parties also challenged BPA's decision in the WP-02 rate proceeding to allocate the costs of the REP Settlement Agreements to the PF Preference rate. *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037 (9th Cir. 2007) ("*Golden NW*"). On May 3, 2007, the Court held that the REP Settlement Agreements executed by BPA and the IOUs were inconsistent with the Northwest Power Act. *See Portland General Elec. Co. v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007) ("*PGE*"). As a result of the Court's decision, BPA prepared to resume the REP by negotiating new RPSAs with its Utility customers. In addition to the RPSAs, BPA conducted this consultation proceeding to revise the ASC Methodology.

3. INITIATION OF THE 2008 ASC METHODOLOGY CONSULTATION PROCESS

3.1 Procedural Background

In the wake of the Court's decisions in *PGE* and *Golden NW,* BPA commenced a series of public workshops to discuss the 1984 ASC Methodology. These discussions began on August 1, 2007, when the Administrator initiated a series of public meetings in which informal comment was taken on issues pertaining to the 1984 ASC Methodology. Later, on August 22, 2007, BPA held a workshop to consider various ASC issues and to begin exploring future ASC options, including potential changes.

Thereafter, on September 10, 2007, BPA held a workshop to discuss a BPA straw proposal that included attributes of a revised ASC Methodology. BPA also presented a number of ASC scenarios. BPA customers responded with their own proposal, which was discussed at a public workshop on September 17, 2007.

At an October 10, 2007, public workshop, BPA requested feedback on four key issues on the ASC Methodology. These issues were: (1) the general construct BPA should use for the ASCM; (2) whether to include return on equity as a resource cost; (3) whether to include income and revenue taxes as a resource cost; and (4) whether to include transmission as a resource cost. BPA also asked participants to present any other issues to BPA.

Subsequently, BPA held a public working session on a proposed ASC filing template on October 16, 2007. The following week, on October 22, 2007, BPA held another public workshop to discuss a proposed construct for the ASC Methodology. At this meeting, BPA provided an outline of the proposed process along with a rationale for each element of the process. The IOUs and Oregon Public Utilities Commission (OPUC) also submitted informal preliminary comments in response to BPA's request for feedback. A week later, on October 30, 2007, another workshop was held where both IOUs and customer-owned-utilities (COUs) presented comments in response to BPA's request for feedback on the ASC Methodology. Later, on November 15, 2007, BPA held another public workshop to discuss ASC issues.

On February 7, 2008, BPA published a notice in the Federal Register (73 Fed. Reg. 7270, February 7, 2008), which presented a proposed ASC methodology, based in large part on public comment, which redefined the types of capital and expense items includable in ASC, established new data sources from which ASCs were to be derived, and changed the nature and timing of BPA's procedures for review of ASC filings by utilities participating in the REP. This notice also contained detailed procedures for public participation in the consultation proceeding. The notice solicited a new round of formal written comments from interested members of the public and provided for an extended comment period that ran from February 8, 2008, through May 2, 2008. The notice also delineated BPA's formal consultation proceeding, which was intended to facilitate the compilation of a full record upon which the Administrator would base a decision to establish a new ASC Methodology.

Although preliminary informal comments had already been made by some groups and members of the public, the notice formally solicited public comment. With the issuance of the proposal, BPA solicited different approaches, new ideas and other types of feedback from interested parties. The proposal was developed with guidance from public workshops and was meant to provide a foundation to facilitate further ideas and approaches.

In order to participate in the Residential Exchange Program during FY 2009, a Pacific Northwest utility was required to notify BPA of its intent to participate by February 22, 2008. A utility was also required to submit an ASC filing (an Appendix 1) to BPA by March 3, 2008, or BPA would use the corresponding Appendix 1 from its WP-07 Supplemental Power Rate Adjustment Proceeding as the base filing to determine the utility's ASCs for FY 2009. During the comment period on the proposed ASC Methodology, interested parties had the opportunity to participate in an expedited process for determining exchanging utilities' ASCs for FY 2009 based on the proposed methodology. The expedited process is described in greater detail below. In addition to the comments submitted, BPA sought to be apprised, through this expedited process, where improvements or changes to the proposed methodology could be made. Workshops were held during the comment period to help facilitate feedback and explore different ideas. BPA sought to develop, in concert with the region, an ASC Methodology that would be legally sustainable, efficient, and durable over time.

Interested members of the public were afforded the opportunity to make written comments between February 8, 2008, and May 2, 2008. Comments were required to be received by 5:00 p.m., Pacific Prevailing Time, on the specified date in order to be considered in the Record of Decision for the ASC Methodology, which would be submitted to FERC for interim and final approval. As discussed more fully below, BPA also posted written comments on its website.

On February 12-13, 2008, BPA made a formal presentation to the Northwest Power and Conservation Council and sought the Council's comments on the proposed ASC Methodology. Thereafter, BPA conducted numerous workshops, including those held on March 6, 13, 21, and 31, 2008, which covered general ASC Methodology issues. Beginning on April 16, and continuing on April 17, 18, 23, and 25, 2008, BPA held additional workshops which focused on specific topics that had been previously raised. A wide variety of topics were covered, including New Large Single Load (NLSL) issues; functionalization issues and comments; ASC filing and review process feedback; review of the ASCM Forecast Model; forecast normalization issues; materiality thresholds for resource additions and large capital; improvements; escalators; transmission; return on equity and taxes; a revised ASC filing template (email and posted); adjusting the ASCM for COUs with a High Water Mark (HWM) contract; rate of return for COUs; resource ownership; consolidation of financial data; treatment of PF BPA purchases in the Forecast Model; treatment of Slice purchases in the Forecast Model; and the Oregon Public Purpose Charge (OPPC) and conservation costs.

BPA also conducted formal briefings and consultations with the OPUC on March 11, 2008; the Montana Public Utilities Commission (MPUC) on March 14, 2008; the Idaho Public Utilities Commission (IPUC) on March 27, 2008; and the Washington Utilities and Transportation Commission (WUTC) on April 10, 2008. The public comment period closed on May 2, 2008. All comments were posted for public review on BPA's ASC Methodology website (http://www.bpa.gov/applications/publiccomments/closedcommentlisting.aspx).

On April 18, 2008, early on in the process, BPA submitted filing templates to the parties for review and comment. With the collaboration of the parties obtained during the course of the workshops and public comment, BPA revised the filing template, known as the Expedited Review Process utility filing template, and submitted it for further comment on May 14, 2008. Additional comments were requested by May 19, 2008, and a workshop was conducted on May 23, 2008, to collaborate on expedited process issues lists. On May 29, 2008 BPA distributed a draft ASC Methodology Record of Decision for public comment.

By the close of comment on May 2, 2008, BPA had received comment from a wide array of customer groups. Participants submitting comments included all six of the region's investor-owned-utilities (IOUs) and the state utility commissions of Idaho, Montana, Washington and Oregon. Comments were also received from groups representing a large segment of BPA's preference customers, including Western Public Agencies Group (WPAG), the Public Power Council (PPC), and the Power Resource Cooperative (PRC). Finally, Snohomish Public Utility District (Snohomish), BPA's largest customer owned-utility (COU), also filed comments.

3.2 Initial 2008 ASC Methodology

BPA's February 2008 proposed ASC Methodology was intended to implement section 5(c) of the Northwest Power Act in a manner that alleviated the administrative burden and expense associated with the jurisdictional approach to ASC determinations, and to reflect changes in the organization and operation of the electric utility industry since the 1984 ASC Methodology was approved. In preparing the proposal, BPA took into account the issues and concerns raised by parties during workshops held in August through November of 2007. Although BPA proposed a number of broad changes to the 1984 ASC Methodology, the proposal was not a complete reconstruction of the previous 1984 ASC Methodology. Several portions of the proposal reflect features from the 1984 ASC Methodology that remain viable in today's environment.

BPA proposed changes to a number of areas in the ASC Methodology. The first area of change was in the manner cost data was collected for a Utility's ASC. Both the 1981 and 1984 ASC Methodologies used the jurisdictional costing approach for ASC determinations. Using the jurisdictional cost approach as the data source for the ASC calculations has proven to be inefficient, cumbersome, and extremely contentious. BPA therefore proposed to not use a jurisdictional costing approach for the revised ASC Methodology. In its place, BPA proposed to use the FERC Form 1, a data source that is uniform and that facilitates ease of administration for all parties.

The second area of change was to the ASC Determination Process Guidelines. BPA proposed to review each Utility's filed ASC in a simplified administrative process. This process would commence during the period prior to BPA filing an initial proposal for a change in wholesale power rates, referred to as the Review Period. An investor-owned utility would submit a "base period ASC" to BPA using data from the prior year's Form 1 on or before May 1 of each year. For Utilities not required to submit a Form 1 to FERC, the base period ASC would be determined from a filing similar in format to a Form 1. The

Utility's base period ASC would be projected by BPA to determine the ASC for the BPA rate period.[3] Escalating the cost data used to determine the base period ASC to be consistent with the test year(s) of the BPA rate proposal addresses many issues of temporal consistency between ASCs and BPA's PF Exchange rate. As a general matter, once the Administrator determines the ASC for each Utility, the ASC will remain at that level for the term of the BPA rate period.

BPA intended to begin implementing the REP for eligible utilities on October 1, 2008. To meet this objective, BPA must complete negotiations with Utilities on new RPSAs, complete the consultation process on the ASC Methodology, and establish ASCs. As noted below, BPA also planned to test the proposed ASC Methodology in an expedited ASC review during the spring of 2008 to identify any problems that might arise in implementing the Methodology. The results of the expedited ASC review will be used in BPA's WP-07 Supplemental Rate proceeding, and will form the starting point for the determination of final ASCs for FY 2009.

A third area of proposed changes was for Transmission investments and expenses. All transmission investments and expenses were included in ASCs under BPA's 1981 ASC Methodology. In the 1984 ASC Methodology, BPA adopted a compromise on transmission that included "all existing transmission, as defined in the Commission Uniform System of Accounts, in service as of July 1, 1984…", but excluded future transmission investment that could not meet two criteria. *See* 1984 ASCM ROD at 42. BPA's proposed ASCM proposed returning to BPA's original position of allowing all transmission investment in the determination of ASC.

The 1984 ASC Methodology did not allow return on equity (ROE) in ASCs, but instead permitted the inclusion of the Utility's long-term cost of debt. Because of changes in the utility industry over the past twenty-four years, and based on BPA's experience in implementing the ASC, BPA proposed that Utilities should again be allowed to exchange ROE.

Under the revised ASC Methodology, BPA proposed to allow Utilities to exchange the costs of certain taxes through their ASCs. BPA proposed this change because it is necessary to have symmetry between its treatment of ROE and taxes. As noted above, BPA proposed to allow the costs associated with equity return as a resource cost in calculation of ASC. If the cost of Federal income taxes at the marginal tax rate is not also included, then an investor-owned utility's cost of resources would be understated. Because BPA is proposing to include ROE as a resource cost in the ASC Methodology, BPA also proposed to gross up the equity component by the Federal income tax rate when determining an investor-owned utility's weighted cost of capital in ASC.

3.3 <u>Expedited ASC Review Process</u>

The 2008 proposed ASC Methodology set up a separate review process called the Expedited Review Process that would run parallel to the revised ASC Methodology. BPA's purpose in conducting an Expedited Review Process was two-fold. First, BPA needed to develop forecast ASCs for its WP-07

[3] BPA will forecast the utility's ASC for an additional four years as required for the section 7(b)(2) rate test in BPA's wholesale power rate adjustment proceedings.

Supplemental rate case that reflected, as close as possible, the ASCs that would likely be in effect during the rate period. Since BPA had commenced a consultation process, and was proposing numerous revisions to the ASCM, developing ASCs under the proposed ASCM was the most reasoanble way to forecast these ASCs. Second, the Expedited Review Process would provide BPA and its customers with invaluable insight into the practical application of the proposed ASCM. Developing ASCs under the procedural and substantive terms of the ASCM would give BPA and the exchanging utilities a working understanding of both the benefits and limitations of the proposed ASCM. These experiences could then be used by BPA and the parties to identify ways in which the proposed ASCM could be improved.

BPA notified parties of the Expedited Review Process in its February 7, 2008, Federal Register Notice. *See* 73 Fed. Reg. 7270 (Feb. 7, 2008). In the notice, BPA announced that a Utility intending to participate in the REP beginning October 1, 2008, must notify BPA of its intent by February 22, 2008. If a Utility failed to notify BPA of its intent to participate in the REP in FY 2009 by February 29, 2008, the Utility would be ineligible to receive any REP benefits during the FY 2009 rate period. A Utility had to file its Appendix 1 based on the proposed ASC Methodology with BPA by March 3, 2008. If it failed to do so, BPA would rely on the Appendix 1 for the Utility included by BPA in its WP-07 Supplemental Rate Proposal to determine ASCs for FY 2009.

The Expedited Review Process was not limited to only exchanging utilities. Any interested party had the opportunity to intervene in BPA's review. Petitions to intervene were due by March 11, 2008. A total of 18 parties intervened in the process.

After BPA develops the final proposed ASC Methodology, BPA will file the Methodology with FERC for confirmation and approval. BPA hopes to receive interim approval of the Methodology on or around September 1, 2008. After FERC submittal, BPA proposes to review the ASC data resulting from the expedited ASC review. BPA will compare the proposed ASC Methodology provisions with the FERC-submitted Methodology. If there are no differences between the data included in the Utilities' Expedited Process and the Appendix 1s to be filed under the final Methodology, the Utilities' Expedited Process data can be used for the Utilities' forecast ASC determinations for the final WP-07 Supplemental Rate proposal. If the Expedited Process data are the same but the substantive criteria of the Methodology have changed from the initial proposed Methodology, BPA will recalculate each Utility's ASC by reviewing the Expedited Process data and applying the final Methodology criteria. Because the Utility's Expedited Process data will have been reviewed, BPA will conduct an abbreviated review with all interested parties to ensure that the Utilities' ASCs comply with the FERC-approved Methodology. When BPA determines that the ASCs comply, BPA will establish the ASCs as the Utilities' WP-07 Supplemental ASCs for FY 2009.

4. RESOLUTION OF SUBSTANTIVE ISSUES

4.1 ASC FILINGS AND PROCEDURAL REQUIREMENTS

4.1.1 Consequences For Denial Of Intervention

Issue

Whether Section III(A) of the ASCM should allow BPA to reduce Utilities' ASCs to the PF Exchange rate in the event BPA or any of its regional power sales customers has been denied the right to participate in the Utility's retail rate proceedings with rights equivalent to the Utility's retail customers.

Parties' Positions

The WUTC argues that BPA should eliminate this provision because it is unnecessary, superfluous, creates a potential for conflict with state or federal law, and imposes an unfair penalty. (WUTC, ASC0005 at 9.)

BPA's Position

BPA's proposed ASCM provides that if BPA or any regional power sales customer is denied participation rights in a Utility's retail review proceeding with rights equivalent to any retail customer of the Utility, BPA may set the Utility's ASC equal to the PF Exchange rate for the Exchange Period.

Evaluation of Positions

Section III(A) of BPA's proposed ASCM states:

> BPA may intervene in each retail rate proceeding for each Utility participating in the Residential Exchange Program. If BPA or any of its Regional Power Sales Customers has been denied the right to participate in a retail rate review proceeding of a filing Utility with rights equivalent to any retail customer of the Utility, BPA may set that Utility's ASC equal to the PF Exchange Rate for the following Exchange Period. Exchanging consumer-owned utilities must provide BPA and Regional Power Sales Customers with at least 180 days notice of their intent to change their retail rates.

The WUTC argues BPA should eliminate this provision because it is unnecessary, superfluous, creates a potential for conflict with state or federal law, and imposes an unfair penalty. (WUTC, ASC0005 at 6-9.) The WUTC argues the intervention provision is unnecessary because BPA is proposing to shift away from jurisdictional data sources to FERC Form 1 data and therefore participation in rate proceedings at state commissions is not necessary. (*Id.*) The intervention provision does not serve a useful purpose because if BPA or one of its public agency customers wants to become a party in a state commission rate proceeding in order to advocate for the commission to allow lower power costs in an exchanging utility's rates, that interest is already well-served by utility customer intervenors, consumer boards (*e.g.,* Public Counsel in Washington) and the commission staffs. (*Id*.)

The WUTC states that if the purpose for intervention is to gather information, that purpose can be fulfilled in any one of three ways, none of which requires BPA or a BPA power customer to have "rights equivalent to any retail customer of the Utility." (*Id*.) First, participation by BPA or one of its power customers could be allowed, but limited in scope to serve only this information gathering purpose. (*Id*.) Second, requests can be made to the WUTC for information included in rate proceedings. (*Id*.) Even confidential information may be obtainable under terms of protective orders. (*Id*.) Third, the WUTC and the exchanging utility could be subject to discovery requests within the BPA proceeding to review ASC costs. (*Id*.)

The WUTC argues that BPA's proposed intervention provision may also create a conflict with state law because intervention in a state rate proceeding is governed by state law, and intervention decisions are left to the state regulatory commission to determine. (*Id*.) BPA cannot by regulation grant a legal right to intervene in state rate proceedings that may be contrary to state law. (*Id*.)

The WUTC notes that the purpose of its rate proceedings is to set fair, just, reasonable and sufficient rates for services provided by regulated utilities. (*Id*.) The Commission exercises discretion in granting requests to intervene in such proceedings by balancing how a petitioner's intervention will benefit this purpose against the cost it will impose on the commission, other parties and the process. (*Id*.) Among other factors, the WUTC considers whether and how the proceeding will affect the interest of the petitioner; whether those interests are among those the agency is required to consider; whether those interests are already represented in the proceeding; whether the interests of the requesting party will unnecessarily broaden the scope of issues; and whether the requesting party brings some unique value to the proceeding. (*Id*.) Ultimately of course, if BPA or one of its customers cannot meet the legal standard for intervention before a state commission, the state commission must deny the intervention. (*Id*.) For example, the WUTC cannot consider the interests of non-regulated entities that are not customers of the utility. (*Id*.)

Finally, the WUTC argues BPA's proposed intervention provision could force the WUTC to either violate state standards by allowing a particular public power customer of BPA to intervene over the lawful objections of other parties to the proceeding, or adhere to state standards by denying intervention, and risk BPA enforcing its rule and denying the regulated utility's customers of REP benefits to which they otherwise are entitled under section 5(c) of the Northwest Power Act. (*Id*.) In short, the proposed intervention provision improperly places state procedural standards in conflict with an exchanging utility's right under federal law to an accurate determination of ASC. (*Id*.) Thus, the WUTC recommends that BPA delete the provision III(A) from the ASCM because it is unnecessary, superfluous, and creates a potential conflict between state and federal law. (*Id*.)

BPA appreciates the WUTC's thorough comments on this issue. As noted above, the WUTC suggests intervention in state proceedings is no longer necessary because of a shift to obtaining information from FERC Form 1s instead of jurisdictional rate proceedings. BPA acknowledges that, in light of the use of FERC Form 1 data, the need for intervention in state proceedings is not as critical as under the 1984

ASCM's jurisdictional approach. Nevertheless, the proposed ASCM still contains certain provisions that rely on state regulatory commission determinations (e.g., return on equity) and it remains necessary to be able to obtain information through retail rate proceedings.

The WUTC argues that BPA cannot by regulation grant a legal right to intervene in state rate proceedings that may be contrary to state law. BPA, however, is not creating a legal right to intervene in state rate proceedings, but rather is establishing a potential consequence for purposes of implementing the REP in the event that BPA or its customers are not permitted to participate in retail proceedings. It is also important to recognize that the prescribed penalty is not automatic. The proposed ASCM provides that "BPA *may* set that Utility's ASC equal to the PF Exchange Rate," not that such action is mandatory. Furthermore, there are two sides to this coin. BPA's preference customers pay significant costs of the REP through the PF Preference rate. As long as some of the costs of the REP are still determined based on state commission retail rate proceedings (when such costs are reflected in ASC determinations), BPA and its customers have a legitimate interest in understanding how such costs are derived and treated.

Significantly, the WUTC states that "participation by BPA or one of its power customers could be allowed, but limited in scope to serve only this information gathering purpose." BPA does not expect that BPA or its customers will raise or litigate substantive retail ratemaking issues before the state commissions. In the event BPA and/or its customers seek to do so, their interventions before the state commissions should be determined by the state commissions based on the commissions' respective rules governing substantive intervention. BPA believes it is far more likely that BPA and/or its customers will seek to intervene only to obtain information from, and to understand, the utilities' filings and the commissions' reviews of such filings. Indeed, BPA has a long history of intervening in state commission retail rate proceedings solely to obtain relevant information for the REP. BPA believes it would be relatively simple for the state commissions to allow interventions by BPA and/or its customers for this limited purpose. Because BPA does not want to overburden the state commissions or the retail rate filing utilities, a commission could grant BPA such an intervention and consolidate any BPA customers seeking such informational interventions in order that parties in the state proceedings need only serve two additional parties with materials during the proceeding. Such an approach would allow BPA and parties to obtain needed information; would not unduly burden the commissions or parties to the state retail rate proceedings; and would not conflict with the commissions' respective intervention rules, which historically have permitted such forms of intervention.

Decision

BPA will amend Section III(A) of the proposed 2008 ASCM as follows:

> *BPA may <u>petition to</u> intervene in each retail rate proceeding for each Utility participating in the Residential Exchange Program. If BPA or any of its Regional Power Sales Customers has been denied the right to <u>intervene</u> in a retail rate review proceeding of a filing Utility <u>when such intervention is for purposes of obtaining any information regarding costs or facts relevant to the determination of a Utility's ASC</u>, BPA may set that Utility's ASC equal to the PF Exchange Rate for the following Exchange Period.*

Exchanging consumer-owned utilities must provide BPA and Regional Power Sales Customers with at least <u>*60*</u> *days notice of their intent to change their retail rates.*

4.1.2 <u>Right Of State Regulatory Commissions To Intervene In BPA's ASC Reviews</u>

<u>Issue</u>

Whether BPA should provide state regulatory commissions an automatic right of intervention in BPA's ASC review proceedings.

<u>Parties' Positions</u>

The WUTC suggests that state regulatory commissions should be provided an automatic right to intervene in BPA's ASC review proceedings. (WUTC, ASC0005 at 10.)

<u>BPA's Position</u>

BPA's proposed ASCM allows only BPA's regional power sales customers an automatic right to intervene in BPA's ASC review proceedings.

<u>Evaluation of Positions</u>

The WUTC cites Section III(D) of BPA's proposed ASCM, which applies to intervention in BPA's ASC review proceedings. (WUTC, ASC0005 at 9-10.) This section provides BPA's regional power sales customers an automatic right of intervention in its ASC review process. (*Id.*) By contrast, other interested parties, including state regulatory agencies, must petition BPA and be granted intervention status by BPA. (*Id.*) The WUTC notes that BPA has the authority to control participation in its proceedings and has the discretion to include intervention policies in its regulations. (*Id.*) The WUTC suggests BPA should include the state regulatory commissions in the BPA review process described in Section III(D) in the proposed ASCM. (*Id.*)

The WUTC also notes that state utility regulatory commissions have an obvious interest to represent in the ASC review (utility customers), plus the expertise and information that may prove valuable to BPA in its review process. (*Id.*) In contrast to Section III(A), the WUTC states that participation by state regulatory commissions as parties in these review processes would be relevant to BPA's review, not burdensome, and could enhance rather than impede efficiency. (*Id.*) The WUTC recommends that Section III(D) be modified.

BPA believes the WUTC has made a convincing argument and the proposed ASCM should be revised for the reasons stated by the Commission.

<u>Decision</u>

The ASCM will revise Section III(D) of the proposed ASCM to read as follows:

Any Regional Power Sales Customer or state utility regulatory body who so requests will be accorded party status for BPA's ASC review process if said request is received by the established deadline.

4.1.3 Use Of FERC Form 1 As Primary Data Source For ASC Determinations

Issue

Whether BPA should use data from FERC Form 1, and corresponding data from Utilities that do not file FERC Form 1, to calculate Utilities' respective ASCs.

Parties' Positions

Snohomish, IPUC and WUTC support BPA's use of FERC Form 1 as the primary data source for ASC determinations. (Snohomish, ASC0009 at 2; IPUC, ASC0003 at 2-4; WUTC, ASC0005 at 2-4.)

BPA's Position

BPA's proposed ASCM uses FERC Form 1 as the primary data source for ASC determinations.

Evaluation of Positions

Both BPA's 1981 and 1984 ASC Methodologies used the jurisdictional costing approach for ASC determinations. Using the jurisdictional cost approach as the data source for the ASC calculations has proven to be inefficient, cumbersome, and extremely contentious. BPA therefore is proposing to not use a jurisdictional costing approach for the revised ASC Methodology. In its place, BPA is proposing to use a data source that is uniform and that facilitates ease of administration for all parties. Such data can be found for investor-owned utilities in the FERC Form No. 1, a compilation of financial and operating information prepared annually in accordance with the Commission's Uniform System of Accounts for Public Utilities and Licensees. *See* 18 C.F.R. § 101 (2007). Consumer-owned utilities that wish to exchange with BPA will be required to submit equivalent information to establish their ASCs.

Under the proposed ASC Methodology, a Utility may include in its ASC only actual costs documented in its Form 1 or equivalent, with limited exceptions. These exceptions include the following: first, equity return for investor-owned and consumer-owned utilities will be determined in accordance with separate procedures; second, Federal income taxes will be included at the marginal Federal income tax rate; third, the Form 1 does not always contain enough information or level of detail to allow BPA to determine whether costs are includable in ASC, thus requiring supplemental information; and fourth, BPA will require utilities that do not file a Form 1 with FERC to submit audited financial data in a format comparable to the Form 1 and a detailed cost of service analysis prepared by an independent accounting or consulting firm, approved by the Utility's Regulatory Body[4] and used as the basis for setting retail rates currently in effect. BPA's proposal is aimed at simplicity, transparency and minimal administrative burden for all parties.

Snohomish states that BPA should use the proposed 2008 ASC functionalization model for calculation of utility ASCs, beginning in FY 2009. (Snohomish, ASC0009 at 2.) Moving to a standard data source, the FERC Form 1, provides a more consistent data format for exchanging utilities to submit their utility ASCs. (*Id.*) The Form 1 submittal framework will establish a more direct and streamlined verification process for BPA and other exchanging utilities. (*Id.*)

The IPUC states that the 1984 ASC "jurisdictional" methodology was unduly complex and became an administrative burden for all parties. (IPUC, ASC0003 at 2-4.) The IPUC supports BPA's proposal to simplify this process and primarily rely on information commonly available in the annual FERC Form 1 filings. (*Id.*) All of the regional IOUs already are required to collect and file FERC Form 1 information every year. (*Id.*) The procedures and methodology for collecting and assembling this information are well established and relatively consistent throughout the industry. (*Id.*) This change will reduce the administrative burden of and add transparency to the ASCM process. (*Id.*)

The IPUC notes that another advantage of using FERC Form 1 data is that it is updated annually, and the reporting period is the same for all reporting utilities. (*Id.*) The 1984 ASC Methodology relied upon data from state commission rate cases, which may not have been that recent and do not occur on a regular basis. (*Id.*) For those IOUs with service areas in multiple states, each jurisdiction could have used a different test year. (*Id.*) The consistency and timeliness of the FERC Form 1 data should reduce disputes about the information and also simplify the resolution of any disputes that do arise. (*Id.*)

The IPUC notes that Form 1 data are publicly available and relatively easy to access, which should enhance the opportunity for all interested parties to review the information reported by the IOUs. (*Id.*) This transparency should benefit the public review process by making it easier and more efficient for parties to evaluate the data in a shorter time frame. (*Id.*) The Form 1 is "certified" by the submitting utility, and a certified public accountant must attest that the reported data conform to the FERC Uniform System of Accounts. (*Id.*) FERC Form 1 Instructions § 3 at p. i-ii; 18 C.F.R. Part 101. FERC may assess penalties for violations of its regulations if data are not submitted. *Id*. at p. vii; 16 U.S.C. § 825a(a). (*Id.*)

The IPUC states that the proposed methodology for adjusting the Form 1 data for those utilities with service areas outside of the region appears to be a reasonable compromise between complexity and administrative burden and should be sufficiently accurate to minimize any concerns regarding inequitable treatment. (*Id.*) As identified in BPA's Federal Register Notice, the data available from the Form 1 will be historical, but the ASC developed through the Methodology will apply to future BPA rate periods. (*Id.*) Because the ASCs for all utilities will be determined from data from the same period and the same methodology will be used to adjust for temporal consistency, the IPUC finds this

[4] "Regulatory Body" is used here as a defined term: a state regulatory body, consumer-owned utility governing body, or other entity authorized to establish retail electric rates in a jurisdiction.

adjustment to be a reasonable compromise - as long as the FERC Form 1 data from the most recently available year are used. (*Id.*)

The WUTC notes that BPA proposes to change the source of data from which it will determine ASCs from the so-called "jurisdictional approach," which uses state regulatory rate orders, to a "uniform cost approach," which uses standard accounting reports utilities make annually to FERC using the FERC Form 1. (WUTC, ASC0005 at 2-4.) BPA's objective is to propose an approach for determining a utility's ASC that is "aimed at simplicity, transparency and minimal administrative burden for all parties." 73 Fed. Reg. 7273. (*Id.*) The WUTC shares this "laudable" objective. (*Id.*) The WUTC affirms that the jurisdictional approach was "proven to be inefficient, cumbersome, and extremely contentious." (*Id.*) For example, under the jurisdictional approach, BPA required a utility to make a new ASC filing each time that utility changed its retail rates. (*Id.*) With each new ASC filing, BPA initiated a separate, 210-day review process featuring an elaborate procedural schedule that included discovery, objections and multiple comment periods. (*Id.*) If the WUTC issued a rate order each year for that utility, these review processes overlapped, and there was no coordination of schedules among the various utility review processes. (*Id.*)

The WUTC notes that the morass this can create is demonstrated by the fact that during the period 2000 to 2007, the WUTC allowed changes to Puget Sound Energy's retail rates no fewer than 27 times. (*Id.*) Avista's rates in Washington were changed no fewer than 12 times over the same period. (*Id.*) Had BPA not suspended application of the 1984 ASC Methodology because of settlements in the mid-1990s, each of these rate changes would have triggered separate, full-scale 210-day ASC reviews by BPA. (*Id.*) In addition to being overly cumbersome, BPA's current processes also proved contentious when BPA disagreed with the WUTC as to how its rate order should be interpreted. (*Id.*) This led to a lawsuit over the issue. *Wash. Utilities & Transp. Comm'n v. FERC*, 26 F.3d 935 (9th Cir. 1994). (*Id.*) BPA's proposed use of FERC Form 1 data promises to dramatically reduce or eliminate these problems. (*Id.*) BPA's proposal to rely on a uniform data source (FERC Form 1) will improve access to data, transparency of data, and provides a more practical and administratively efficient way for BPA and all interested parties to accomplish the necessary review and approval of ASCs. (*Id.*)

In particular, the WUTC supports BPA's proposal to use FERC Form 1 and the standard annual filing and review process BPA proposes. (*Id.*) The WUTC also supports BPA's proposal to supplement the FERC Form 1 data with jurisdictional data where necessary to include equity return in capital costs and where the Form 1 does not include sufficient detail to functionalize regulatory assets and other account entries. (*Id.*) The WUTC also supports BPA's proposal to supplement the FERC Form 1 data with Federal income tax at the marginal rate. (*Id.*)

Decision

BPA will use FERC Form 1 as the primary data source for ASC determinations.

4.1.4 Proper Base Year to Establish Utilities' FY 2009 ASCs

Issue

Whether Utilities should use 2006 FERC Form 1 filings to establish FY 2009 ASCs.

Parties' Positions

The IPUC suggests that BPA should use Utilities' 2007 FERC Form 1 filings as the basis for establishing FY 2009 ASCs. (IPUC, ASC0003 at 2-4.)

BPA's Position

The Proposed ASCM uses Utilities 2006 FERC Form 1 filings to establish FY 2009 ASCs.

Evaluation of Positions

The IPUC understands that BPA's current proposal is that data from the FERC Form 1 covering the 2006 calendar year will be used in the 2007 (WP-07) Supplemental Rate Proceeding and will apply going forward for the years 2008 and 2009. (*Id*.) The FERC Form 1 data covering the 2007 period was to be filed by April 15, 2008, and therefore should be available now. (*Id*.) Although the IPUC recognizes that the schedule in this proceeding is expedited for the WP-07 case, it believes that using the more recent 2007 data is justified. (*Id*.) The electrical industry in the Pacific Northwest is currently experiencing significant change, and conditions in 2009 are likely to be significantly different from those that existed in 2006. (*Id*.) Although it may be possible to make adjustments to reflect some of the expected changes, the ability to project into the future and reliably predict what will happen diminishes exponentially as the time period is extended. (*Id*.) Using 2007 data as the base should result in significantly more accurate results than starting off with data that is already two years old. (*Id*.) Additionally, each adjustment made to historical data increases the probability of disputes, problems, and delays. (*Id*.) Adjusting 2006 data to reflect 2007 changes, when actual 2007 data are available, will increase this risk unnecessarily. (*Id*.) Expending the extra effort associated with using the 2007 data may prevent the significantly greater effort that would be required to resolve these disputes. (*Id*.)

BPA understands the IPUC's proposal to use 2007 data for determining FY 2009 ASCs. BPA acknowledges that using more recent data is usually desirable. However, BPA believes the use of 2006 data for the FY 2009 ASCs is reasonable. First, FY 2009 is a transition year and the only year for which BPA will use data from three years prior. After the FY 2009 transition year, when BPA determines ASCs, BPA will use the most recent FERC Form 1. In addition, BPA is attempting to better synchronize its ASC determinations used for the actual implementation of the REP and BPA's rate case ASC forecasts, which are used in forecasting REP benefits for ratemaking purposes. If BPA were to use the 2007 data for determining FY 2009 ASCs, it would create a disconnect between what was used to set the PF Exchange rate in the rate case and what is used to set ASCs. Using the proposed ASCM, BPA has conducted an expedited review of Utilities' ASCs for FY 2009. These ASCs will be adjusted to reflect the requirements of BPA's final ASCM. The resulting ASCs will then be incorporated into the development of BPA's proposed wholesale power rates. This will ensure accurate rate case ASC and REP forecasts. If BPA were to use 2007 FERC Form 1 data for the later development of exchanging Utilities' ASCs for purposes of calculating REP benefits for FY2009, there would be a greater difference in the forecasted REP benefits upon which BPA's rates were based and the REP costs BPA actually incurs during the implementation of the REP in FY 2009. For these reasons, it is appropriate to use 2006 data to determine Utilities' FY 2009 ASCs.

Decision

BPA will use 2006 FERC Form 1 data to establish Utilities' FY 2009 ASCs.

4.1.5 Functionalization Of Costs Through Direct Analysis

Issue

Whether Utilities should be allowed to functionalize all accounts through direct analysis.

Parties' Positions

The IOUs propose that Utilities should have the option of performing a direct analysis for all accounts; that accounts to be functionalized by direct analysis should have a default functionalization method; and that accounts should be able to be functionalized in part by direct analysis and in part by a prescribed functionalization method. (IOUs, ASC0004 at 1.)

BPA's Position

The proposed ASCM permits direct analysis only for specified accounts. The proposed ASCM contains default functionalization methods as an alternative to direct analysis where appropriate. The proposed ASCM does not allow parties to use a combination of direct analysis and a prescribed functionalization on the same account.

Evaluation of Positions

The IOUs argue that Utilities should have the option to perform a direct analysis for accounts that are shown in the template as other than DIRECT. (IOUs, ASC0004 at 1.) The option to perform a direct analysis would allow the utility to make the appropriate adjustments. *Id*. BPA does not believe it would be prudent to permit all accounts to be functionalized by direct analysis. As noted in BPA's Federal Register Notice and as documented in the comments received in response to that notice, BPA's previous implementation of the 1984 ASCM was unduly complex and became an administrative burden for all parties. One of BPA's primary goals in revising the ASCM is to reduce the burden of Utilities filing ASCs and to reduce BPA's administrative burden in reviewing and establishing ASCs. Allowing Utilities to perform a direct analysis on every account would add unnecessary complexity and administrative cost to the implementation of the REP. Indeed, allowing so many direct analyses could increase the administrative burden of the proposed ASCM over the 1984 ASCM, which would be directly contrary to BPA's goals. In addition, abuse of functionalization codes was one of the problems with the 1981 ASCM.

> These methods should serve to mitigate significant cost assignment abuses inherent in the existing ASC Methodology, such as changing functionalization methods from filing to filing and the inclusion of improper costs in ASC. BPA retains the authority to review and accept only those functionalized costs it deems appropriate for exchange transactions, as it did under the previous ASC methodology. *1984 ASCM ROD at 79*.

The IOUs argue that, for accounts in the template that are to be functionalized based on direct analysis, a default methodology should be allowed where possible and should be available for use in current and future ASC filings. *Id*. BPA agrees that where accounts are to be functionalized by direct analysis, a default methodology should be prescribed where appropriate. There are only a small number of accounts where BPA has not provided a default functionalization. BPA has not provided default functionalizations for these accounts because FERC Form 1 provides little, if any, supporting information on such accounts. BPA must require "direct analysis only" in order that BPA can obtain sufficient information to properly functionalize these accounts.

The IOUs argue there are instances where a portion of a plant account may be functionalized based upon direct analysis, while other portions of such account may relate to the company as a whole and should be allocated. *Id*. For example, NorthWestern has costs in Account 303 that are 100% transmission and software costs that relate to all functions. *Id*. BPA does not believe this would be a reasonable approach. If a Utility performed a direct analysis, it would have identified the proper manner in which all costs in an Account should be functionalized: Production, Transmission and Distribution/Other. After determining the portions of costs that were eligible for inclusion in ASC (Production and Transmission), any remaining costs would not be eligible. It makes no sense to apply a functionalization ratio to costs already known to be ineligible. Such an approach would permit improper costs to be included in exchangeable costs.

<u>Decision</u>

BPA will permit direct analysis only for specified accounts. The ASCM contains default functionalization methods in the absence of direct analysis where appropriate. BPA will not allow parties to use a combination of direct analysis and a prescribed functionalization method for the same account.

4.1.6 <u>Single ASCs For Utilities With Multiple State Jurisdictions</u>

<u>Issue</u>

Whether BPA should establish a single ASC for Utilities with multiple state jurisdictions.

<u>Parties' Positions</u>

The WUTC supports the establishment of a single ASC for multi-state Utilities. (WUTC, ASC 0005 at 24-25.) The IOUs argue BPA should use the jurisdictional cost allocation for each retail jurisdiction in accordance with the approved state allocation methodology. (IOUs, ASC0004 at 7.)

BPA's Position

The proposed ASCM establishes a single ASC for multi-state Utilities.

Evaluation of Positions

The WUTC notes that BPA proposes to develop a single ASC for each utility, even if that utility serves retail customers in more than one Pacific Northwest state. (WUTC, ASC0005 at 24-25.) The WUTC recognizes this proposal is a departure from BPA's 1981 and 1984 ASC Methodologies, which relied on jurisdictional information from each state to establish a separate ASC for a utility in each state. (*Id.*) PacifiCorp is the only utility that serves in more than one Pacific Northwest state and also serves in states outside of the Pacific Northwest. (*Id.*) BPA proposes to rely on the aggregate of PacifiCorp's state filings of operations (for example, annual commission-basis reports) to capture the allowed allocation of its system-wide costs to the in-region loads eligible for the REP. (*Id.*) The Commission understands and agrees that establishing a single ASC for PacifiCorp's service within the Pacific Northwest may require some supplementation of FERC Form 1 data with standard reports the utility files with the commissions in each of the Northwest states in which it operates. (*Id.*) Although there may be details yet to work out about which state reports are used and how they are combined, the WUTC believes BPA's proposal is both appropriate and practical. (*Id.*)

The IOUs state that BPA should use the jurisdictional cost allocation for each retail jurisdiction in accordance with the approved state allocation methodology. (IOUs, ASC0004 at 7.)

BPA agrees with the WUTC and the IOUs that a single ASC should be established for multi-state Utilities.

Decision

BPA will establish a single ASC for Utilities with multiple state jurisdictions. The ASCM will use the jurisdictional cost allocation for each retail jurisdiction in accordance with the approved state allocation methodology.

4.1.7 Date For Utilities' ASC Filings

Issue

Whether BPA should require Utilities to file ASC information by May 1 each year for BPA's review and determination of a base period ASC.

Parties' Positions

The WUTC supports a requirement for Utilities to file ASC information each year for BPA's review and determination of a base period ASC, but proposes to change the deadline from May 1 to June 1. (WUTC, ASC0005 at 4-10.) The WUTC recommends that BPA permit adjustments to return on equity, Federal income taxes, and debt costs if those figures change during the pendency of the BPA rate proceeding, and suggests adjustments to true-up short-term purchases and sales of wholesale power if BPA accepts the alternative to normalization the Commission suggests in Section J of its comments. (*Id.*) The WUTC supports BPA's proposal to allow utilities to file multiple, contingent, ASCs to reflect expected new or retired resources and changes to service territories, but recommends that BPA limit such filings to material changes – for example, addition of new resources, new contract costs, or service territory changes that produce a change in ASC in excess of 2.5 percent. (*Id.*)

BPA's Position

BPA's proposed ASCM provides that Utilities must file ASC information by May 1 each year for BPA's review and determination of a base period ASC. The proposed ASCM does not permit adjustments to return on equity, Federal income taxes, and debt costs if those figures change during the pendency of the BPA rate proceeding, or for adjustments to true-up short-term purchases and sales of wholesale power. The proposed ASCM allows utilities to file multiple, contingent, ASCs to reflect expected new or retired resources and changes to service territories, and limits such filings to material changes.

Evaluation of Positions

The WUTC notes that BPA proposes to require Utilities to file ASC information by May 1 each year for BPA's review and determination of a base period ASC. (WUTC, ASC0005 at 4-10.) In years when BPA proposes its own rate changes, these standardized Utility ASC filings will form the basis for BPA's initial rate proposal and will be escalated to BPA test-year dollars and finalized with all other information current at the close of BPA's rate proceeding. (*Id.*) This procedure provides appropriate flexibility by allowing a Utility to make multiple ASC filings to reflect the expected additions or retirements of major resources and the impact of additions to or loss of service territory. (*Id.*) These alternative ASCs become effective only when the new resource actually comes on-line, the retired resource is actually retired, or the service territory changes actually occur. (*Id.*) The WUTC believes BPA's proposal to standardize the schedule for ASC filings will improve administrative efficiency and that BPA has appropriately balanced the constraints inherent in standardization with the flexibility for utilities to update costs when they are material, known and actual. (*Id.*) The WUTC supports BPA's proposal to implement a standard schedule for annual ASC filings and data review. (*Id.*)

Although the WUTC supports BPA's basic proposal to require utilities to file ASC information each year for BPA's review and determination of a base period ASC, it suggests BPA should move the filing date to June 1 instead of May 1. (*Id.*) Because the utilities file FERC Form 1s with FERC each April, and because the WUTC requires commission-basis reports based on the FERC Form 1 to be filed no later than four months after the close of fiscal year (typically April 30), it recommends that BPA consider modifying its ASC filing date to be June 1 to accommodate utility preparation of complete filings. (*Id.*) BPA believes the WUTC's argument is well-reasoned and supports changing the filing date to June 1.

The WUTC supports BPA's proposal to allow utilities to update information to be contemporaneous with BPA's test-year. (*Id.*) It agrees with BPA's observation that this method is analogous to rate-setting using an historical test-year that incorporates end-of-period adjustments. (*Id.*) However, the WUTC recommends that BPA permit adjustments to return-on-equity, Federal income taxes, and debt costs if those figures change during the pendency of the BPA rate proceeding. (*Id.*) The WUTC suggests adjustments to true-up short-term purchases and sales of wholesale power should also be permitted if BPA accepts the alternative to normalization the Commission suggests in Section J of its comments. (*Id.*) In response to these arguments, BPA believes it would be inappropriate to permit adjustments to return-on-equity, Federal income taxes, and debt costs if those figures change during the pendency of the BPA rate proceeding. Adjustments to true-up short-term purchases and sales of wholesale power also should not be permitted. First, in developing the proposed ASCM, BPA has attempted to make the implementation of the Methodology simpler and more efficient. The proposed changes for the foregoing subjects would create unneeded complexity. Also, the proposed ASCM requires ASC filings each year, with base ASC adjustments every two years. This provides relatively timely incorporation of data into BPA's ASC determinations. In addition, accommodating changes for return-on-equity, Federal income taxes, debt costs, short-term purchases and sales of wholesale power would create a much greater administrative burden for BPA and implementation burden for the exchanging utilities. The BPA Review Period for ASC filings is short, about 165 days as compared to 210 under the 1984 ASCM. In addition, BPA and participants in the ASC review process will be reviewing all ASC filings concurrently. If a state commission issued a rate order in the middle or near the end of the process, BPA and other participants in the ASC review process would have little time to review and analyze the information. Furthermore, the proposed ASCM is intended to provide all parties with greater stability for forecasting and receiving REP benefits. The more variables that can change ASCs create less stability and predictability for the REP. For these reasons, BPA has limited interim changes in ASCs to accommodate only resource changes and changes to service territories.

The WUTC supports BPA's proposal to allow utilities to file multiple, contingent, ASCs to reflect expected new or retired resources and changes to service territories. *Id*. The Commission recommends that BPA limit such filings to material changes – for example, addition of new resources, new contract costs, or service territory changes that produce a change in ASC in excess of 2.5 percent. *Id*. BPA agrees with the WUTC that such filings should be limited by a materiality standard. BPA also concurs that changes of 2.5 percent or greater of a Utility's Exchange Period ASC is an appropriate materiality standard.

<u>Decision</u>

BPA will require that Utilities must file ASC information by June 1 each year for BPA's review and determination of a base period ASC. The ASCM will not permit subsequent updates to return on equity, Federal income taxes, debt costs, short-term purchases or sales of wholesale power. The ASCM will allow Utilities to file multiple, contingent, ASCs to reflect changes to service territories. The ASCM will allow for changes to ASC resulting from major resource additions and reductions as discussed in section 4.2.

4.1.8 Failure To File Appendix 1

Issue

Whether a Utility's failure to file an Appendix 1 should constitute termination of the RPSA if the failure is not cured.

Parties' Positions

Snohomish argues that a Utility's failure to file an Appendix 1 should constitute termination of the RPSA if the failure is not cured. (Snohomish, ASC0009 at 2.)

BPA's Position

The proposed ASCM provides that after the initial and second Exchange Periods, if a Utility fails to file its Appendix 1 by May 1 of the year preceding BPA's establishment of new Wholesale Power Rates, BPA may set the Utility's ASC equal to the PF Exchange rate until the end of the Exchange Period.

Evaluation of Positions

Section II.B.3 of the Proposed ASCM provides:

> 3. Failure to File an Appendix 1 and Patently Deficient Appendix 1
>
> *a. Failure to File an Appendix 1.* If a Utility fails to file its initial Appendix 1 by the time designated by BPA, BPA may use the WP-07 Supplemental Appendix 1 as a default for the initial 1-year Exchange Period, *i.e.*, until October 1, 2009. Following the initial 1-year Exchange Period under this Methodology, Exchange Periods shall be equal to the term of subsequent BPA wholesale power rate periods, beginning on October 1 of each year that BPA establishes new Wholesale Power Rates. After the initial and second Exchange Periods, if a Utility fails to file its Appendix 1 by May 1 of the year preceding BPA's establishment of new Wholesale Power Rates, BPA may set the Utility's ASC equal to the PF Exchange rate until the end of the Exchange Period.
>
> * * *
>
> *c. Period to Cure.* If a Utility fails to file an Appendix 1 by the time designated by BPA, or if it files an ASC which BPA determines is patently deficient, BPA shall provide such Utility with written notice and a period of seven (7) days within which to file, or re-file, as the case may be, a new or corrected Appendix 1. In the event the Utility fails to file or re-file, as specified above, by the end of the seven-day cure period, or if such re-filed Appendix 1, is likewise determined patently deficient, BPA may set the Utility's ASC equal to the PF Exchange rate until the end of the Exchange Period.

In summary, the proposed ASCM provides that after the initial and second Exchange Periods, if a Utility fails to file its Appendix 1 by May 1 of the year preceding BPA's establishment of new Wholesale Power Rates, BPA may set the Utility's ASC equal to the PF Exchange rate until the end of the Exchange Period.

Snohomish argues that a Utility's failure to file an Appendix 1 should constitute termination of the RPSA if the failure is not cured. (Snohomish, ASC0009 at 2.) Snohomish notes that, as currently established, a utility's failure to timely file an Appendix 1, or the filing of a deficient Appendix 1, simply results in no benefits during the two-year Exchange Period. (*Id.*) Snohomish claims this creates an alternative to incurring a deemer balance should the utility anticipate that its ASC will drop below the PF Exchange rate during that period. (*Id.*) To fix this loophole, BPA should revise the ASC Methodology to state that a utility's failure to file an Appendix 1, or the filing of a deficient Appendix 1, will result in termination of the RPSA for the term of that agreement, provided that the failure or deficiency is not corrected. (*Id.*)

Snohomish has identified a legitimate concern. Under the proposed ASCM, a Utility could fail to file an Appendix 1 in order to avoid accumulating a deemer balance. This would be inappropriate. Snohomish's proposed solution, however, may not establish a proper remedy. If a Utility were required to terminate its RPSA, there is nothing that requires the termination to be for the full term of the terminated RPSA. The Utility could later offer to sell power to BPA at its ASC pursuant to section 5(c) of the Northwest Power Act and resume participation in the REP after the period in which it should have accumulated a deemer balance. Therefore, in order to address the problem, BPA proposes that a Utility's failure to timely file an Appendix 1 will result in a waiver of the Utility's right to participate in the ASC review proceeding to establish its ASC. BPA will make the Utility's Appendix 1 filing. All other parties will be permitted to participate and present arguments challenging the Utility's ASC. A Utility failing to file an Appendix 1 will also allow BPA discretion to set its ASC for the Exchange Period and BPA shall not be required to include any proposed adjustments for resource changes or changes in service territories in the Appendix 1 filing.

Decision

The ASCM will state that if a Utility fails to timely file an Appendix 1 and refuses to cure the problem, BPA will make the Utility's Appendix 1 filing. The Utility will waive its right to participate in the ASC review proceeding to establish its ASC. All other parties will be permitted to participate and present arguments challenging the Utility's ASC. A Utility failing to file an Appendix 1 will also allow BPA discretion to set its ASC for the Exchange Period and BPA shall not be required to include any proposed adjustments for resource changes or changes in service territories in the Appendix 1 filing.

4.1.9 COU Notice To BPA Of Retail Rate Change

Issue

Whether BPA should change the time required for exchanging COUs to give BPA notice of a retail rate change from six months to 60 days.

Parties' Positions

WPAG suggests BPA should reduce the length of the notice required to be given to BPA by COUs when changing retail rates. (WPAG, ASC0008 at 7-8.)

BPA's Position

Section III(A) of the proposed ASCM requires exchanging COUs to provide BPA and its Regional Power Sales Customers at least 180 days notice of their intent to change retail rates.

Evaluation of Positions

WPAG suggests BPA should reduce the length of notice required to be given to BPA by COUs when changing retail rates. (WPAG, ASC0008 at 7-8.) Under the proposed ASC Methodology, COUs must give BPA 180 days prior notice of a retail rate change. (*Id.*) WPAG notes that because COUs' rates are governed by BPA's rate proceedings, most COU exchangers will not be able to give the six-month notice required by the methodology. (*Id.*) WPAG suggests a 60-day notice period as a more realistic option. (*Id.*) BPA agrees that a 60-day notice period is reasonable.

Decision

BPA will require that exchanging COUs must provide BPA and its Regional Power Sales Customers at least 60 days notice of their intent to change retail rates.

4.1.10 Reviewing ASC Methodology In 2013

Issue

Whether BPA should review the ASC Methodology in 2013 to assess whether the Methodology is fairly and accurately determining utility ASCs.

Parties' Positions

Snohomish suggests that BPA should commit to reviewing and assessing the ASC Methodology in 2013 as a "checkpoint" to assure public power that the ASC Methodology will be a fair and verifiable method to calculate ASCs for exchanging utilities. (Snohomish, ASC0009 at 3.)

BPA's Position

The proposed ASCM already has provisions for revisiting the Methodology. These measures ensure a sufficient level of oversight, alleviating the need for a date certain to review the ASCM.

Evaluation of Positions

Snohomish states that BPA should commit to review the new ASC Methodology in 2013, including the functionalization and direct assignment process for allocation of ASC costs. (Snohomish, ASC0009 at 3.) Snohomish notes that BPA is currently proposing significant changes to the 1984 ASC Methodology. (*Id.*) Many of BPA's public power customers are concerned that these changes will increase the costs of the REP. (*Id.*) Snohomish believes BPA should provide this assessment as a "checkpoint" to assure public power that the ASC Methodology will be a fair and verifiable method to calculate ASCs for exchanging utilities. (*Id.*)

BPA acknowledges it is possible certain aspects of the ASC Methodology may need to be adjusted to address issues identified during its implementation. BPA does not agree, however, that committing to a particular year to review the new ASC Methodology would be productive. BPA anticipates that it will take several years of implementing the new ASC Methodology to fully understand which aspects of the ASC Methodology are working properly and which aspects are not. BPA's expectation is that, during this period, the parties and BPA will work together to address these issues. If some fundamental flaw is ultimately discovered that cannot be resolved through the normal operation of the ASC review process, the new ASC Methodology contains a mechanism that allows BPA or regional parties to request a consultation process to revise the Methodology. Specifically, Section V of the proposed ASC Methodology states that a consultation process may be initiated by the BPA Administrator, by three-quarters of exchanging utilities, by three-quarters of BPA's preference customers, or by three-quarters of the direct service industries (DSIs). This provision is specifically designed to provide all affected customer classes the ability to request a consultation process. BPA believes this mechanism should be sufficient to address any serious defects in the ASC Methodology.

Furthermore, if BPA were to adopt Snohomish's suggestion, it may inhibit BPA and the parties from addressing serious problems in the ASC Methodology that arise before 2013. This could occur if major flaws in the Methodology were discovered or if the electric industry were to undergo a substantial change. In these instances, waiting until 2013 to make changes to the Methodology could result in significant harm to the exchanging utilities or to the COUs paying the costs of the REP in rates.

Finally, as a practical matter, it is not prudent to commit the Administrator to review and revise the ASC Methodology in any particular year. BPA and the region have limited resources. These resources are often strained just dealing with the immediate issues BPA and its customers must address on a daily basis. It is not reasonable to commit BPA and its customers to another public process five years in advance without any indication that such process will be necessary or warranted, or that such review would be practical given whatever additional activities BPA and its customers are engaging in at that time. The better course is to allow BPA and the region to identify the issues they believe must be resolved and when such issues should be resolved.

<u>Decision</u>

BPA will not commit to reviewing and assessing the new ASC Methodology in 2013. The new ASC Methodology already contains mechanisms to allow interested parties to request a consultation process to revise the Methodology. These provisions provide sufficient protection to BPA's customers in the event BPA or its customers encounter any difficulties implementing the new ASC Methodology.

4.2 ASC Forecast Methodology

4.2.1 ASC Forecast Escalators

Issue

What are the appropriate escalators and price forecasts for BPA to use in order to escalate base period ASC costs to Exchange Period ASC costs?

Parties' Positions

Parties did not comment on this issue.

BPA's Position

BPA proposes using Global Insight's forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products.

Evaluation of Positions

Generally, BPA is proposing that ASC forecasts use the same sources and types of escalators and price forecasts BPA uses when setting rates. This issue was discussed with stakeholders during the consultation process, and received broad approval by the parties in attendance.

Decision

BPA will use Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. These are the most accurate escalators available to BPA at this time, and use of these escalators will ensure parity in the forecast of costs included in BPA rates and costs included in ASCs during the rate period and Exchange Period.

4.2.2 Base Data Escalation Timing

Issue

Whether base data should be escalated to the beginning, mid-point or end of the Exchange Period when forecasting Exchange Period ASC costs.

Parties' Positions

The IOU's state that FERC Form 1 data for a given year reflects expenses incurred throughout that entire year and reflects investment as of the end of that year. (IOU, ASC0004 at 7.) Therefore, escalation of that data to a year in the BPA rate period must be calculated to reflect the full period of escalation from the end of the FERC Form 1 year to the end of the year in the BPA rate period to which costs are being escalated. (*Id*.)

BPA's Position

The proposed ASCM provided that escalation of base year data to the Exchange Period forecast should be to the midpoint in time of the Exchange Period.

Evaluation of Positions

In the Federal Register Notice publishing the draft ASCM, BPA proposed calculating an Exchange Period ASC that would be in effect for the entire 2-year Exchange Period, unless a major resource was added. Therefore, BPA believed it was appropriate to escalate base period costs to the midpoint of the 2-year Exchange Period. BPA believed that this would help meet its objective of ease of administration for the REP. In addition, BPA escalates to the midpoint of each year the costs that BPA includes to develop its revenue requirement. In the interest of equity, it is appropriate to escalate the costs used to calculate Exchange Period ASCs on the same basis as BPA escalates its costs for setting rates. For a 1-year rate period, that is the midpoint of the year. The equivalent point for a 2-year period is the midpoint of the 2-year period.

Decision

The ASCM will escalate base period costs to the midpoint of the fiscal year for a 1-year rate period/Exchange Period, and to the midpoint of the 2-year period for a 2-year rate period/Exchange Period to calculate Exchange Period ASCs. This will ensure that costs included in both BPA's rates and exchanging utilities' ASCs are escalated on the same basis.

4.2.3 Price Forecast for PF Power

Issue

Whether to use BPA's forecast of PF rates and prices for the various power products that BPA provides.

Parties' Positions

Parties did not comment on this issue.

BPA's Position

This issue was not addressed in the proposed ASCM.

Evaluation of Positions

During the ASC consultation process, it was noted that COUs can purchase power products from BPA that are not available to the IOUs. Therefore, it may be more appropriate to project future costs of products purchased from BPA using BPA's forecasted price. The costs that go into the rate projections are subject to public scrutiny during public processes conducted by BPA, and the resulting rate and price projections are available to all parties. BPA agrees that this approach is reasonable, and should be adopted.

Decision

The ASCM will base the costs of power products purchased from BPA on BPA's forecast of prices for its products.

4.2.4 Major Resource Additions Allowed in ASC Forecast

Issue

What types of future investments should be considered major resource additions for purposes of determining Exchange Period ASCs?

Parties' Positions

The IOUs argue major resource and transmission investments and contracts should be allowed to trigger an ASC change within a rate period. (IOU, ASC0004 at 6.) Long-term contracts may substitute for generation and transmission resources. (*Id*.) As such, long-term contracts are comparable to major resources and should be allocated to either production or transmission. (*Id. at 7.*) Utilities may make major expenditures that are associated with major resources, transmission projects or contracts - *e.g.,* pollution control, plant rehabilitation or hydro relicensing costs and fees. (*Id*.) These expenditures, if they meet the materiality test, should be allowed to trigger a change in a utility's ASC. (*Id*.)

BPA's Position

The proposed ASCM provided that changes to an established ASC would be allowed to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet that utility's retail load during the BPA rate period.

Evaluation of Positions

This issue arises from BPA's proposal to use historical base period costs, and then project those costs forward to the Exchange Period in order to calculate Exchange Period ASCs. Between the base period and the Exchange Period, utilities may add resources to meet load growth and/or to meet additional regulatory or environmental requirements. BPA is proposing to determine the Exchange Period ASC's during a public review process prior to the start of the Exchange Period, so a method needs to be developed that allows for projecting, reviewing, and approving the costs of any major resource additions.

In their comments, the IOUs identified the following types of investments that should result in a change in a utility's ASC:

1. Resource (production or generating) investments
2. Transmission investments
3. Long-term generating or transmission contracts
4. Pollution control and environmental compliance investments
5. Plant rehabilitation investments, and
6. Hydro relicensing costs and fees

BPA agrees that these types of investments are part of a utility's cost of resources and should be included in the utility's costs for determining its Exchange Period ASCs provided that the particular addition meets the materiality test. The costs of generating resources have always included the initial investment cost (subject to a prudence review). Any required environmental or pollution control investments associated with that resource must be made or the resource would not be allowed to operate. Rehabilitation investments are needed to keep the resource operating efficiently. Hydro relicensing costs and fees are a necessary expenditure for getting approval for the resource to operate and meet load. These costs and fees are generally included in intangible assets or regulatory assets and liabilities. In the Transmission Cost Projection section (4.2.8) BPA explains the method it will us for inclusion of future transmission resources additions.

Decision

The ASCM will include the costs of resource additions and other resource costs identified above in determining an exchanging utility's Exchange Period ASC, subject to meeting the materiality threshold. Relicensing costs included in intangible plant or regulatory assets and liabilities will be subject to the same functionalization rules and procedures as all other regulatory assets and liabilities.

4.2.5 Resource Addition Costs in Forecast

Issue

How should the costs of major Production-related resource additions and reductions be projected for inclusion in Exchange Period ASCs?

Parties' Positions

Parties did not comment on this issue.

BPA's Position

In the proposed ASCM, BPA indicated that exchanging utilities would submit a separate ASC filing for each major resource addition or reduction. This filing would contain all of the costs associated with the major resource. The utility's ASC would be adjusted when the major resource began commercial operation or was transferred or retired.

Evaluation of Positions

The proposed ASCM described, in general terms, the method BPA proposed for projecting the costs of major resource additions and reductions:

Major Resource Additions

1. In the event a Utility has a major resource projected to come on-line or be purchased and used to meet that Utility's retail regional load during the BPA rate period, the Utility will submit two ASC filings:

2. One conforming to the Form 1 described above, and

3. A second filing that incorporates the costs in the appropriate year(s) associated with the new resource based on the expected commercial operation date of the new resource or, for resource purchases, the date the sale is completed and the purchased resource is used to meet the Utility's regional retail load.
   a. In addition to including the estimated capital and operating costs of the new resource, the Utility must also estimate the changes in purchased power expense, sales for resale credit and other costs based on the additional generation provided by the new resource.
   b. Because the commercial on-line dates of power plants often change during the construction process, BPA will not adjust the Utility's ASC until the new generating resource begins commercial operation.

Major Resource Reductions

1. For a major resource used to meet the Utility's Contract System Load that is projected to be retired, sold, or otherwise unavailable to serve load during the BPA rate period, BPA proposed that the Utility make two ASC filings:

2. One conforming to the Form 1 described above, and

3. A second filing that excludes the costs associated with the retired, sold, or otherwise unavailable to serve load resource based on the expected retirement or closing date of the resource.

a. In addition to including the reduction in estimated capital and operating costs of the retired, sold, or otherwise unavailable to serve load resource, the Utility must also estimate the changes in purchased power expense, sales for resale credit and other costs based on the generation formerly provided by the retired or sold resource.
b. BPA proposes not to adjust the Utility's ASC until the official retirement or transfer date of the generating resource.

This issue was discussed during the ASCM consultation process, and this general approach accepted by participating parties as a reasonable approach.

In developing the ASC Forecasting Model, BPA further developed the forecast methodology for (a) projecting the costs of major resource additions, and (b) determining the change in a utility's ASC and when the change will take effect. This methodology consists of the following nine steps, which will replace the previous language in section IV of the ASC Methodology.

1. The exchanging utility will provide its forecast of major resource addition and all associated costs. The forecast will cover the period from the end of the base period to the end of the Exchange Period.

2. The forecast of the major resource costs to be included in the utility's Exchange Period ASC will be reviewed and determined during the review period.

3. The costs will be included in the forecast model at the time the resource is forecast to come on-line or the purchase is available to meet the utility's regional loads.

4. All resources included prior to the start of the Exchange Period will be projected forward to the mid-point of the Exchange Period.

5. For each major resource addition, BPA will calculate the difference in ASC between the ASC without the new resource and the ASC with the new resource (the ASC delta).

6. When the resource comes on-line, BPA will add the ASC delta to the utility's then current ASC to determine its new ASC.

7. For each major resource addition forecast to (be available to meet regional retail load) during the Exchange Period, BPA will calculate the difference in ASC between the ASC without the new resource and the ASC with the new resource (the ASC delta) at the mid-point of the Exchange Period.

8. When the resource comes on-line, BPA will add the ASC delta to the utility's then current ASC to determine its new ASC.

9. Steps 1 through 8 above will also be used in a similar manner for resources that are sold, transferred or retired.

Decision

BPA will use the foregoing method to determine the change in ASC due to major new production-related resource additions or reductions. These additions will include new production or generating resource investments, long-term generating or power purchase contracts, pollution control and environmental compliance investments relating to generating resources or contracts, and plant rehabilitation investments.

4.2.6 Materiality Threshold for Resource Additions

Issue

What constitutes a material change in costs that will result in a change to a utility's ASC for major resource additions or reductions?

Parties' Positions

The IOUs state that major generation or transmission investments or contracts that exceed a materiality level should be added to the FERC Form 1 data as a within period ASC adjustment. (IOU, ASC0004 at 6.) They recommend a materiality threshold based on either a specified dollar per MWh change in ASC (perhaps $1 per MWh), or a change in Contract System Cost above a specified dollar amount (perhaps $10 million). (*Id.*)

The Idaho PUC encouraged BPA to maintain some flexibility for including new major resource additions in ASC calculations. (IPUC, ASC0003 at 5-6.)

BPA's Position

The proposed ASCM provided that an ASC change would occur for major resource additions or reductions, but did not specifically address what would constitute a major resource addition or reduction.

Evaluation of Positions

This issue was discussed extensively with parties during the ASCM consultation process. Most parties agreed it would be administratively burdensome, and not worth the effort to develop a new ASC for every change in resource costs, no matter how small. Three alternatives were considered during the consultation process to define what would constitute a material change in resource costs sufficient to justify a change in ASC.

1. Base the threshold on a specified dollar per MWh change in ASC.
2. Base the threshold on a specified dollar change in Contract System Cost.

3. Base the threshold on a specified percentage change in ASC.

Alternative 1 was not favored because parties perceived this would affect high-ASC utilities differently than low-ASC utilities. Similarly with Alternative 2, parties did not favor this alternative because smaller utilities might never reach the dollar threshold, even though a change in Contract System Cost lower than the threshold could result in a substantial change in small utilities' ASCs. This left Alternative 3, a percentage change in ASC. Parties felt this would be the fairest approach. There was general agreement that a 2.5% change in ASC was a reasonable threshold for triggering a change in a utility's ASC.

Decision

BPA will adopt a materiality threshold of a 2.5% change in a utility's Exchange Period ASC for determining when a change in ASC will be made for resource additions or reductions.

4.2.7 Transmission Cost Projections

Issue

How should the ASCM project the costs of transmission additions from the Base Period through the Exchange Period?

Parties' Positions

The IOUs argue major resource and transmission investments and contracts should be allowed to trigger an ASC change within a rate period. (IOU, ASC0004 at 6.) Long-term contracts may substitute for generation and transmission resources. (*Id.*)

BPA's Position

BPA proposes to escalate the Base Period average per-MWh cost of Transmission forward to the mid-point of the Exchange Period, and to use the escalated average cost to determine the Transmission-related cost of meeting load growth since the Base Period. This cost will be included in the Exchange Period ASC.

Evaluation of Positions

Although the Federal Register Notice described in general terms how the costs of major resource additions would be included in a utility's ASC, it did not specifically address new transmission investments. In developing the ASC Forecast model, BPA initially considered treating new transmission investments in the same way new generating resource additions would be treated. The utility would provide its forecast of major transmission investments, which would be reviewed during the ASC review period to determine the costs to be included in the utility's ASC. However, during the expedited review process the limitations of this approach soon became apparent. Many of the proposed

transmission investments are too small to be material, and much of the supporting documentation is not as rigorous as that available for proposed generating resource additions.
BPA is proposing to include the costs of transmission as part of a utility's ASC. Therefore, it is appropriate to include the costs of future transmission investments in ASC. BPA's proposed method accomplishes this by including a forecast of additional investment costs needed to serve the utility's post Base-Period load growth. This method avoids the need to determine the portion of the costs of new transmission investments incurred for out of region sales, or to wheel power for other utilities. In addition, the costs of new transmission investments actually incurred will be included in future Base Period costs.

Decision

BPA will project the utility's costs of transmission investments needed to meet load growth using the escalated average cost of transmission.

4.2.8 Distribution Plant Additions Forecast

Issue

How to project the costs of distribution plant additions from the Base Period through the Exchange Period.

Parties' Positions

Parties did not comment on this issue.

BPA's Position

BPA proposes to escalate the Base Period average per-MWh cost of Distribution Plant forward to the mid-point of the Exchange Period, and use the escalated average cost to determine the distribution-related cost of meeting load growth since the Base Period. This cost will be included in the Exchange Period ASC.

Evaluation of Positions

This issue is important because Distribution plant costs are used in the calculation of the PTD ratio. If BPA did not include the costs of new Distribution plant in the ASC forecast, then the Production and Transmission components of the PTD ratio would increase relative to the Distribution component. This would result in a greater portion of costs that were functionalized using the PTD ratio being included in ASC. Therefore, BPA proposes to project the costs of new distribution plant investments using the same method it is proposing for projecting the costs of new transmission plant.

When BPA examined the FERC Form 1s of the IOUs, BPA discovered that the IOUs are making substantial investments in distribution plant. Therefore, it is appropriate to include the costs of new distribution plant when calculating the PTD ratios for Exchange Period ASC determinations. BPA's proposed method accomplishes this by including a forecast of additional costs of distribution plant needed to serve the utility's post Base Period load growth. Similar to transmission, the costs of new distribution plant actually incurred will be included in future Base Period costs.

Decision

BPA will project the utility's costs of Distribution plant additions needed to meet load growth using the escalated average cost of Distribution.

4.2.9 Confidential Data for Major New Resources and the Review Process

Issue

Whether confidentiality of any new major resource addition can be used by an exchanging utility to restrict interested parties from reviewing and analyzing key data required by the ASCM.

Parties' Positions

Parties did not comment on this issue.

BPA's Position

The proposed ASCM did not specifically address the issue of confidentiality of major resource addition information.

Evaluation of Positions

During the expedited review process, several exchanging utilities did not provide forecasted data for new major plant additions because they did not want the other parties to know their resource forecasts. A major underpinning of the ASCM is that all costs included in ASC be available for review by interested parties. The need for this transparency is particularly acute here because the utility is providing forecast data that will be used to establish another ASC that will result in overall higher REP benefits if applied during the Exchange Period. If BPA and other interested parties cannot fully vet these forecasts because of confidentiality concerns, then the filing utility would have a strong incentive to provide only high estimates of the projected new major resource.

This is not to suggest that BPA is unwilling to consider measures to protect the utility's confidential business information. BPA can establish procedures for the Review Process to protect the confidentiality of the information. These procedures can protect the information from unnecessary disclosure while at the same time allowing other parties meaningful access to the data.

Therefore, for a new major plant addition to be included in ASC, its projected costs and output must be available to be critically reviewed and analyzed by interested parties.

Decision

BPA will issue special procedural rules to ensure the confidentiality of information provided by utilities regarding any new major resource additions as part of its Review Process. Failure to provide needed information may result in exclusion of the related costs from ASC. However, as is the case for other utilities that do not have major resource additions in a particular year, load growth will be assumed to be met with purchases on the wholesale market, as described in Section 4.2.13. What the utility loses by not supplying confidential resource data is the difference between the cost of the resource and the price of electricity in the wholesale market.

4.2.10 Changes in Utility Service Territory

Issue

How will a change in a utility's ASC be determined when there is a change in the utility's service territory?

Parties' Positions

Parties did not comment on this issue.

BPA's Position

In the proposed ASCM, BPA proposed that the exchanging utility would submit a separate ASC filing for each purchase or sale of service territory. This filing would contain all of the costs associated with the change in service territory. The utility's ASC would be adjusted when the sale or purchase was finalized.

Evaluation of Positions

In the proposed ASCM, BPA suggested the following treatment for determining the change in an exchanging utility's ASC when it adds to its service territory or sells part of its service territory:

Changes to Service Territory

1. In the event that a Utility acquires a new service territory or relinquishes a portion of its service territory, the Utility will submit two ASC filings:

2. A base year filing, and

3. A second filing that incorporates:
   a. The increase or reduction in Contract System Load associated with the acquisition or reduction in service territory.

b. The increase or reduction in Contract System Costs associated with the acquisition or relinquishment of the service territory.
c. In addition to including the estimated capital and operating costs increases or reductions resource, the Utility must also estimate the changes in purchased power expense, sales for resale credit and other costs based on the changes in the service territory
d. Because the date of the forecasted change in the new service territory could change during the period, BPA will not adjust the Utility's ASC until the change in service territory takes place.

This is similar to the treatment BPA proposed for changing ASCs due to major resource additions or retirements.

Decision

BPA will determine a change in ASC using the method described above when a utility acquires a new service territory or sells a portion of its existing service territory.

4.2.11 Normalization of Short-term Purchased Power and Sale for Resale

Issue

Whether short-term purchased power and sales for resale should be normalized.

Parties' Positions

The IOUs argue if BPA does not normalize short-term purchased power and sales for resale then BPA should true-up short-term purchased power using ASCs from actual FERC Form 1 data for each year. (IOU, ASC0004 at pages 1-2.) In the absence of a true-up, the IOUs argue that net power cost (Accounts 447, 501, 547 and 555) should be averaged. (*Id.*) In addition, the IOUs argue that each utility should have a one-time option to elect for the contract term to average net power supply expenses on a rolling five-year basis. (*Id.*) The average should utilize real dollars to allow for effects of inflation. (*Id. at 5.*)

The WUTC argues that volatility in short-term purchased power and sales for resale suggests that some "smoothing" or normalization be used to recognize that a single-year's FERC Form 1 will not fairly represent actual costs in any subsequent years in the Exchange Period. (WUTC, ASC0005 at 25-26.) The WUTC argues that 5-year rolling averages would be more representative of expected actual figures than data from a single FERC Form 1 or any other single, historical year's data. (*Id.*) As an alternative, the WUTC would support an approach that "trues-up" the most recent Form 1 data to actual sales and purchases during the period of a BPA rate proceeding, and prices these figures at the forecast BPA uses in its rate-setting. (*Id.*)

BPA's Position

The proposed ASCM suggested using a rolling 5-year average of short-term (less than 1 year) energy sales and energy purchases in the Appendix 1 to determine the quantity of short-term sales and purchases. In the event the 5-year data are not available or incomplete, BPA would use the data available.

Evaluation of Positions

It is essential that the short-term purchased power and sales for resale revenues be accurately reflected in the forecasted ASCs. BPA recognizes that a single-year's FERC Form 1 short-term purchased power and sales for resale revenues might not accurately represent future short-term purchased power and sales for resale revenues under normal operating conditions. This was the reason BPA proposed using the five-year rolling average in the proposed ASCM. The WUTC contends that a single-year's FERC Form 1 will not fairly represent actual costs in subsequent years. The WUTC argues that BPA should either (1) normalize short-term purchases and sales for resale or (2) true-up these costs and revenues to the most recent FERC Form 1 during the period of the BPA rate proceeding. The IOUs contend that use of the FERC Form 1 data can create potential for anomalous power costs in ASCs. The IOUs propose two alternatives: (1) trued-up ASCs from actual short-term purchases and sales for resale FERC Form 1 data for each year, or (2) each utility should have a one-time option to elect for the contract term to average net power supply expenses (Accounts 447, 501, 547 & 555) on a rolling five-year basis.

This issue was discussed extensively with parties during the ASCM consultation process.
It was concluded that for the base period the utilities would be in resource balance (load was met), balancing their systems through the use of purchased power, sales for resale and varying the operation of generating units. The resource balance reflected in the base period would be dependent on key factors such as hydro conditions, weather, and other variables. It was realized that BPA's five-year rolling average normalization of short-term purchased power expenses and sales for resale revenues, without normalizing the costs of generating resources, would not be a predictor of the costs of operating those resources under normal conditions.

BPA and the parties concluded it would not be practical for BPA and the interested parties to develop the models and analysis that would be required to normalize all of the variables that go into estimating the operation of each of the exchanging utilities' systems under normal conditions. Therefore, BPA and the parties agreed not to normalize the short-term purchases and sales-for-resale and operations of other generating units.

In addition, BPA believes that changing ASCs every two years will mitigate much of the potential bias that might be introduced from not normalizing purchases and sales that could fluctuate significantly in a hydro based system. For any given base period, the ASCs may be higher or lower than would be expected under normal conditions but with the more frequent ASC determinations (every two years) these should even out over time.

A true-up for purchases and sales accounts to the most recent FERC Form 1 would not accurately reflect the most current operating costs, unless other operating costs such as fuel and plant O&M accounts were also trued-up. The same flaws, described above, would be present regardless of which year FERC Form 1 is used.

The IOUs' proposal to average net power supply expenses on a rolling five-year basis (Accounts 447, 501, 547 & 555) would introduce the same analytical complexities described above. Any averaging approach implies a different resource operation from the base period and would require not only normalizing the costs, but also normalizing the generation operations. As described above, this would require relatively complex analysis and modeling.

Decision

BPA will not normalize short-term purchases and sales-for-resale. The short-term purchases and sales-for-resale for the base period will be used for the starting values for the forecast. The utilities will then be allowed to include new plant additions and use a utility specific forecasted purchased power and sales for resale price to value purchased power expenses and sales for resale revenue.

4.2.12 Market Price Forecast for Power Purchases and Power Sales

Issue

Whether a single market price should be used to forecast both power purchases and power sales.

Parties' Positions

The IOUs state that the use of a single average Market Price from AURORAxmp should be expanded to permit the development of heavy-load hour and light-load hour market prices and purchase and sale market prices. (IOU, ASC0004 at 10.) The IOUs state that utilities throughout the region have different operating characteristics, so the price they pay for purchased power versus the price they sell surplus power can be different. (*Id*.) This difference will affect future ASCs going forward. Each utility should have the option of using the blended average rate from AURORAxmp or using two distinct rates for purchases and sales, all of which are outputs from AURORAxmp. (*Id*.)

BPA's Position

In the Federal Register Notice for the proposed ASCM, under Rules for Determining Exchange Period ASC, BPA stated that it would use models and methodologies used to develop market price forecasts in BPA's subsequent initial wholesale power rate filings.

Evaluation of Positions

BPA recognizes that utilities throughout the region have different operating characteristics, so the price they pay for purchased power versus the price they sell surplus power can be different. This difference will affect future ASCs. For this reason the IOUs argue that each utility should have the option of using the blended average rate from AURORAxmp or using two distinct rates for purchases and sales, all of which are outputs from AURORAxmp. (IOU, ASC0004 at page 10.)

When developing the ASC forecast model, BPA used the same market price to forecast all utilities' power purchases and power sales. Subsequently, BPA examined individual utilities' base data for market purchases and market sales and discovered large differences between the price utilities paid for power purchases and the price they received for market sales. BPA therefore concluded that it would be appropriate to develop separate market prices to forecast short-term market purchases (as defined by FERC) and sales for resale (as defined by FERC).

The methodology BPA proposes to use to forecast the short-term purchase power price and short-term sales for resale price for each utility follows:

1. The average short-term purchased power price and short-term sales for resale price will be calculated for each year for the most recent three years of actual data.

2. The mid-point between the average short term purchased power price and short term sales for resale price will be calculated for each year.

3. The percentage spread around the mid-point between the average short term purchase power price and short term sales for resale price will be calculated for each year.

4. A weighted spread (for the most recent three years of actual data) will then be calculated. The following weighting scale will be used:
   a. 3 times current year spread
   b. 2 times (current year minus 1) spread
   c. 1 times (current year minus 2) spread
   This weighted average spread will be used in the forecast.

5. The base period mid-point value will be escalated at the same rate as BPA's market price forecast.

6. The average spread calculated in 4 above will then be applied to the forecasted mid-point to determine the forecasted purchase power price and short term sales for resale price

An example of how BPA will calculate the short-term purchased power and sales for resale prices is as follows:

1) <u>Short Term Purchased Power and Sales For Resale Average Calculation</u>

$$\textbf{ST-PP}_{\text{average}} = \frac{\Sigma\ [\ \Sigma\ \text{SF}_{\text{Total Settlement}} + \Sigma\ \text{OS}_{\text{Total Settlement}} + \Sigma\ \text{EX}_{\text{Total Settlement}} + \Sigma\ \text{AD}_{\text{Total Settlement}}\ ]}{\Sigma\ [\ \Sigma\ \text{SF}_{\text{MWh}} + \Sigma\ \text{OS}_{\text{MWh}} + \Sigma\ \text{EX}_{\text{MWh}} + \Sigma\ \text{AD}_{\text{MWh}}\ ]}$$

$$\textbf{ST-SFR}_{\text{average}} = \frac{\sum \left[\sum SF_{\text{Total Settlement}} + \sum OS_{\text{Total Settlement}} + \sum EX_{\text{Total Settlement}} + \sum AD_{\text{Total Settlement}} \right]}{\sum \left[\sum SF_{\text{MWh}} + \sum OS_{\text{MWh}} + \sum EX_{\text{MWh}} + \sum AD_{\text{MWh}} \right]}$$

2) <u>Mid – Point Calculation</u>

Mid –Point = [$\text{ST-PP}_{\text{average}}$ + $\text{ST-SFR}_{\text{average}}$] / 2

3) <u>Percent ST-PP and ST-SFR Spread around the Mid – Point Calculation</u>

If ST-PP > ST-SFR

Percent Spread ST-PP = [$\text{ST-PP}_{\text{average}}$ / Mid-Point] –1

Percent Spread ST-SFR = 1- [$\text{ST-SFR}_{\text{average}}$ / Mid-Point]

4) <u>Percent Spread Weighting Calculation</u>

Weighting (Current price weighted more than earlier prices)

- Base period (Most current year) = 3
- Base period minus 1 = 2
- Base period minus 2 = 1

e.g.

- Base period (2006) = 3
- Base period minus 1 (2005) = 2
- Base period minus 2 (2004) = 1

Forecasted Spread = [(Percent Spread $_{2006}$ * 3) + (Percent Spread $_{2005}$ * 2) + (Percent Spread $_{2004}$ * 1)] / 6

5) **<u>Forecasted Mid-Point</u>**

Mid-Point $_{2007}$ = Mid-Point $_{2006}$ * [BPA Mkt Price $_{2007}$ / BPA Mkt Price $_{2006}$]

6) **<u>Forecasted Short Term Purchased Power and Sales For Resale Prices</u>**

If ST-PP > ST-SFR

ST-PP$_{2007}$ = Mid-Point $_{2007}$ * [1 + Forecasted Spread]

ST-SFR$_{2007}$ = Mid-Point $_{2007}$ * [1 – Forecasted Spread]

<u>Decision</u>

BPA will use the method described above to determine separate market prices to forecast short-term purchased power expense and sales for resale revenues to calculate Exchange Period ASCs.

4.2.13 Meeting Forecast Load Growth

Issue

Whether BPA should use market purchases to meet forecasted load growth.

Parties' Positions

Parties had no comments on this issue.

BPA's Position

The Federal Register Notice containing the proposed ASCM did not explicitly address how the cost of meeting load growth would be forecasted.

Evaluation of Positions

During consultation with the parties, BPA proposed that all load growth not met by new resource additions would be met by purchased power at the forecasted utility-specific short-term purchased power price *(see 4.2.12. Market Price Forecast for Power Purchases and Power Sales)*:

1. BPA will meet all of the utility's load growth with market purchases priced at the utility's forecasted short-term purchased power price unless the utility has forecasted major resource additions.

2. In the event of major resource additions, new load growth will be met by the new resource. If the new resource is less than total new load growth the unmet load growth will be met with market purchases priced at the utility's forecasted short-term purchased power price.

3. In the event that a new resource exceeds load growth the excess will be sold as surplus power into the market priced at the utilities forecasted sales-for resale price.

Decision

The ASCM will provide that all load growth not met by new resource additions will be met by purchased power at the forecasted utility-specific short-term purchased power price.

4.2.14 Escalators for Long-Term (LT) and Intermediate-Term (IT) Purchases and Sales

Issue

What are the appropriate escalators for BPA to use in order to escalate base period LT and IT purchases and sales to the Exchange Period?

Parties' Positions

Parties had no comments on this issue

BPA's Position

In the proposed ASCM, BPA proposed to escalate long–term and intermediate-term (as defined by FERC) firm purchased power costs and sales for resale revenues at the rate of inflation.

Evaluation of Positions

In consultation with the parties, it was concluded that without detailed information regarding the terms and conditions of the long–term and intermediate-term firm purchased power contracts, escalation at the forecasted rate of inflation was a reasonable approach for projecting future cost changes for existing contracts.

Decision

BPA will escalate long–term and intermediate-term (as defined by FERC) firm purchased power costs and sales for resale revenues at the rate of inflation.

4.3 Functionalization Codes

Introduction

The 2008 ASC Methodology will incorporate, in part, the functionalization process and functionalization codes, with modifications, determined in the 1984 ASCM. Functionalization of each Account included in a Utility's ASC shall be according to the functionalization prescribed in Attachment A, Table 1. Assignment of the functionalization codes will be to either Production (PROD); Transmission (TRANS); Distribution/Other (DIST); a statistically derived ratio of a combination of any or all three classifications (PTD, PTDG – includes General Plant, TD); or with a direct analysis (DIRECT) prepared by the filing Utility. Direct analysis is subject to BPA review and approval. The utility prepared direct analysis shall categorize costs to Production and Transmission functions as allowed by the ASC Methodology.

Direct analysis may only be performed if Table 1 indicates that a Utility may perform a direct analysis on the Account. This option allows a utility to assign costs in the specified Account to production, transmission and/or distribution/other based on analysis and support from the Utility which demonstrates that such cost assignment is appropriate. The utility shall submit with its ASC filing any and all work papers, documents, or other materials which demonstrate that the functionalization contained in its direct analysis assigns costs based upon the actual and/or intended functional use of those items. Failure to submit such documentation will result in the entire Account being functionalized to Distribution/Other for all schedules with exception of items included in Schedule 3B, *Other Included Items*, where the Account will be functionalized to Production.

Functionalization of certain Accounts may be based on direct analysis or with a default ratio associated with that specific Account as shown on Table 1. Once a Utility uses a specific functionalization method for an Account, the Utility may not change the functionalization for that Account without prior written approval from BPA.

The following issues were specifically raised during the reconsultation process. Functionalization determinations not raised herein are considered appropriate and will be used in the 2008 ASCM. See Attachment A, Table 1 for the complete list of functionalization classifications for each Account.

4.3.1 Acquisition Adjustments (Electric)(Account 114)

Issue

Whether Account 114, Acquisition Adjustments (Electric), should be functionalized using direct analysis.

Parties' Positions

The IOUs suggest these costs should be included in ASC and should be functionalized using direct analysis. (IOU, ASC0004 at 4-5.) For example, Account 114 for PSE for 2006 includes costs relating to a combustion turbine. (*Id*.) As such, these costs are appropriately included in ASC and functionalized as PROD. (*Id*.) The remainder of the plant balance relates to Transmission and Distribution. (*Id*.) The template does appear to allow DIRECT for the related expense (see Amortization of Plant Acquisition Adjustments (Electric) on tab Sch 3 - Expenses). (*Id*.)

BPA's Position

In the proposed ASCM, BPA requires functionalization of Account 114, Acquisition Adjustments, by direct analysis.

Evaluation of Positions

One of the key guiding principles of public utility Accounting and the FERC Uniform System of Accounts is that the cost of an asset included in a Utility's rate base shall be the original cost less depreciation of the asset when it was first devoted to public service. Thus, if a utility purchases a power plant or other asset, such as part of another utility's service territory, at a price above the net book value, the amount above net book value is recorded in Account 114 *Electric Plant Acquisition Adjustments*. This separate Accounting was a result of abuses in the utility industry in the 1920s and 1930s where subsidiary companies of a public utility holding company would sell assets to other utilities of the same public utility holding company at higher prices to inflate utility rate base and thus increase the effective rate of return. Abuse of asset sales by public utility holding companies was one of the major drivers that led to passage of the Federal Power Act in 1935.[5]

The Accounting treatment specified by the FERC Uniform System of Accounts directs that the book value of the Electric Plant be placed in the appropriate plant Accounts (Accounts 310 – 399); the accumulated depreciation and or amortization be placed in Accounts 108 – 115; and the amount the utility paid over book value be placed in Account 114, Electric Plant Acquisition Adjustments.

Two core questions are central to the treatment of Electric Plant acquisition adjustments for ASC purposes, and these are the same questions that are addressed in the numerous FERC, state commission, and state and Federal court rulings concerning acquisition adjustments: (1) should the costs be included in rates base, and (2) should the amortization of these amounts be considered an operating cost? Treatment of acquisition adjustments by the courts, FERC and state regulatory commissions do not offer BPA conclusive guidance on this issue; some state commissions permit utilities to recover acquisition adjustments, FERC and other state commissions do not.

The IOUs point out that some of the costs included in Account 114 include costs related to a combustion turbine and the balance of the costs are Transmission and Distribution related. The IOUs suggest utilities should be allowed to perform a direct analysis on Account 114. BPA agrees with the IOUs on this issue.

Decision

BPA will have Utilities functionalize Account 114 by direct analysis with a default functionalization to Distribution/Other.

4.3.2 Investment in Associated Companies (Account 123)

Issue

Whether Account 123, Investments in Associated Companies, should be excluded from rate base in ASC determinations.

Parties' Positions

PPC/NRU claims that the Investment in Associated Companies account may include unregulated entities. (PPC/NRU, ASC0006 at 13-14.) If so, then COUs would be subsidizing potentially risky activities of IOUs that have nothing to do with resource costs. (*Id.)* PPC/NRU suggests BPA exclude this account completely from ASC. (*Id.)*

BPA's Position

[5] See discussion in § 4.04[2], G. Hahne and G. Aliff, *Public Utility Accounting*, pages 4-9 to 4-14 (Mathew Binder 2005).

BPA's position is that Investment in Associated Companies, FERC Account 123, be functionalized using the PTD ratio. After numerous discussions with participants in the ASCM consultation process concerning the type of items that may be included in Account 123, BPA revised its position on the functionalization of that account.

BPA proposes that exchanging utilities must perform a direct analysis on Account 123, Investment in Associated Companies. If they do not perform a direct analysis, the default functionalization is to Distribution.

Evaluation of Positions

BPA proposes that exchanging utilities must perform a direct analysis on Account 123, Investment in Associated Companies. If they do not perform a direct analysis, the default functionalization is to Distribution. BPA changed its position on this issue as a result of the discussion and analysis in the ASCM consultation process when representatives of IOUs said that some of the items included in Account 123 are utility related, and some are not utility related. The participants in the ASC consultation process agreed that utilities must perform a direct analysis in order for the cost to be included in Contract System Costs.

PPC/NRU contends that allowing Investments in Associated Companies into ASC will cause costs unrelated to an IOU's resources into ASC. (PPC/NRU, ASC0006 at 13.) This concern is based on the region's experience with the combination of regulated and unregulated activities within the same company. (*Id.*) Specifically, PPC/NRU state that it "appears" that Associated Companies "may" be unregulated entities. (*Id.*) If an IOU makes an investment in an Associated (but unregulated) Company, and such investments are allowed in rate base for the purposes of ASC, then BPA's preference customers will be subsidizing potentially risky activities of IOUs that have nothing to do with resource costs. (*Id.* at 13-14.) PPC/NRU state there is no basis for subsidizing these activities because there is no nexus between these activities and generation assets. (*Id.* at 14.) Thus, they argue line 123 of Form 1 should not be subject to direct analysis, but rather should simply be excluded from rate base in the determination of ASC. (*Id.)*

BPA agrees with PPC/NRU that in its proposed ASCM, using the PTD ratio to functionalize Account 123, Investment in Associated Companies, could *potentially* result in non-utility costs being included in Contract System Costs, and therefore shifting those costs to COUs. In response to the concerns of the PPC/NRU and other participants in the ASC consultation process, BPA revised its position to require that Utilities must perform a direct analysis on Account 123, showing that the costs are related to the production and transmission functions of the utility. If the utility's direct analysis does not satisfy BPA, or if the utility does not perform a direct analysis, the amounts included in Account 123 will be functionalized to Distribution, and thus not included in Contract System Cost.

Decision

BPA will require exchanging utilities to perform a direct analysis of Account 123, Investment in Associated Companies. If they do not perform a direct analysis, the default functionalization is to Distribution.

4.3.3 Derivative Instruments (Accounts 175, 176, 244 and 245)

Issue

Whether "Derivative Instruments" (Accounts 175, Derivative instrument assets; Account 176, Derivative instrument assets-hedges; Account 244, Derivative instrument liabilities; and Account 245, Derivative instrument liabilities-hedges) should be functionalized by direct analysis.

Parties' Positions

PPC/NRU argue that IOUs engage in markets for a variety of financial instruments, including puts, calls, swaps, and other "derivatives." (PPC/NRU, ASC0006 at 14.) BPA initially proposed that assets accumulated in "Derivative Instruments" Accounts 175-176 be included in rate base and functionalized to Production for the purpose of ASC. (*Id*.) This assumes that such assets are necessarily related to Production, when they may be related to a number of other activities of the IOU. (*Id*.) Thus, such assets should be subject to direct analysis, because it is not clear that these are associated in every case with generation costs. (*Id*.) In the absence of data necessary for direct analysis, these assets should be excluded from rate base. (*Id*.)

BPA's Position

In the proposed ASCM, BPA functionalized Account 175, *Derivative instrument assets*, and Account 176, *Derivative instrument assets* -hedges, and the corresponding liability Accounts 244 and 245, to Production.

Evaluation of Positions

During the consultation process BPA and the parties achieved general consensus that Derivative Accounts 175, 176, 244, and 245 should be functionalized to Distribution/Other. The parties concluded that Derivative Asset Accounts 175 and 176 would be very close to equal over time to Derivative Liability Accounts 244 and 245. The parties agreed that completing a direct analysis of all the Derivative Accounts would be administratively burdensome with little or no change in the underlying Utilities' ASC. Further, once these transactions are realized or are marked to market, the gain or loss on the derivative is recognized in current earnings in FERC account 555. Expenses in Account 555, Purchased Power are included in the determination of ASC.

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Decision

BPA will functionalize Accounts 175, 176, 244, 245 to Distribution/Other.

4.3.4 Conservation Assets in Account 182.3

Issue

Whether conservation assets in Account 182.3, Other Regulatory Assets, should be included in ASC and functionalized to Production.

Parties' Positions

The IOUs state that PSE's conservation program expenditures are included in Account 182.3 and these costs should be functionalized to Production. (IOU, ASC0004 at 5.)

BPA's Position

In the proposed ASCM, BPA required functionalization of Account 182.3, Other Regulatory Assets, by direct analysis.

Evaluation of Positions

PSE has the option to functionalize all or part of the conservation program to Production as part of a direct analysis. The records supporting the entries to this Account must be kept so the utility can furnish full information regarding the nature and amount of each regulatory asset included in this Account, including justification for inclusion of such amounts in this Account.

The functionalization of conservation programs in Account 182.3 (Other Regulatory Assets) should conform to the requirements established in *4.6.Conservation and Oregon Public Purpose Charge*

Decision

BPA will require a direct analysis for Account 182.3, Other Regulatory Assets, with a default functionalization to Distribution/Other.

4.3.5 Intangible Plant - Franchises and Consents (Account 302)

Issue

Whether Account 302, Intangible Plant – Franchises and Consents, should be functionalized by direct analysis.

Parties' Positions

The IOUs state that for many utilities, Account 302 includes a utility's hydro relicensing costs. (IOU, ASC0004 at 5.) These costs are appropriately included in ASC and should be functionalized by direct analysis. (*Id.*)

BPA's Position

In the proposed ASCM, BPA required Account 302, Intangible Plant – Franchises and Consents, to be functionalized by direct analysis.

Evaluation of Positions

The FERC Uniform System of Accounts directs that Account 302 shall include amounts paid to the federal government, to a state or to a political subdivision thereof in consideration for franchises, consents, water power licenses, or certificates, running in perpetuity or for a specified term of more than one year, together with necessary and reasonable expenses incident to procuring such franchises, consents, water power licenses, or certificates of permission and approval, including expenses of organizing and merging separate corporations, where statutes require, solely for the purpose of acquiring franchises. If a franchise, consent, water power license or certificate is acquired by assignment, the charge to this Account in respect thereof shall not exceed the amount paid therefore by the utility to the assignor, nor shall it exceed the amount paid by the original grantee, plus the expense of acquisition to such grantee. Any excess of the amount actually paid by the utility over the amount above specified shall be charged to Account 426.5, Other Deductions. The foregoing directives support conducting a direct analysis to identify Production or Transmission costs.

Decision

BPA will require Account 302, Intangible Plant – Franchises and Consents, to be functionalized through a direct analysis, with a default functionalization ratio to PTD.

4.3.6 Transportation Equipment (General Plant) (Account 392)

Issue

Whether the functionalization of Account 392, Transportation Equipment (General Plant), should be changed from BPA's proposed TD ratio to include production and thus be functionalized to PTD.

Parties' Positions

The IOUs argue that this Account is traditionally functionalized using PTD in rate proceedings, due to the fact that Production, Transmission and Distribution facilities have and need equipment to transport employees and perform maintenance. (IOU, ASC0004 at 7.) The IOUs suggest the costs should be functionalized to Production, Transmission and Distribution and argue there is no basis for excluding Production costs from the functionalization as proposed by BPA. (*Id.*)

BPA's Position

In the proposed ASCM, BPA functionalized Account 392, *Transportation Equipment (General Plant)*, to TD.

Evaluation of Positions

The IOUs argue that Production, Transmission, and Distribution facilities have and need equipment to transport employees and perform maintenance and that there is no basis for excluding production from the functionalization as proposed by BPA. (IOU, ASC0004 at 7.) BPA concurs with this need; however, BPA notes these costs are already included in rate base Plant-In-Service under the Production Plant schedules. The FERC System of Accounts states Account 392 includes the cost of transportation vehicles used for utility purposes. The IOUs generally include production-related transportation costs within sub-Accounts associated with Plant-In-Service (PIS), Production Plant, Accounts 310-346, and they are functionalized to Production. Therefore, functionalizing Account 392, Transportation Equipment, using the PTD ratio, would overestimate the Production costs for the calculation of a utility's ASC.

Decision

BPA will functionalize Account 392, Transportation Equipment (General Plant), using the TD ratio.

4.3.7 Power Operated Equipment (General Plant) (Account 396)

Issue

Whether the functionalization of Account 396, Power Operated Equipment (General Plant), should be changed from BPA's proposed TD ratio to include production and functionalized to PTD.

Parties' Positions

The IOUs argue that this Account is traditionally functionalized using PTD in rate proceedings, due to the fact that Production, Transmission and Distribution facilities have and need equipment to perform maintenance. (IOU, ASC0004 at 7.) The IOUs argue the costs should be functionalized to Production, Transmission and Distribution and there is no basis for excluding Production from the functionalization as proposed by BPA.

BPA's Position

In the proposed ASCM, BPA functionalized Account 396, Power Operated Equipment (General Plant), to TD.

Evaluation of Positions

The IOUs argue that the Production, Transmission, and Distribution facilities have and need equipment to perform maintenance and there is no basis for excluding Production from the functionalization as proposed by BPA. (IOU, ASC0004 at 7.) BPA concurs with this need; however, BPA notes these costs are already included in the rate base Plant-In-Service under the Production Plant schedules. The FERC

System of Accounts states Account 396 includes power operated equipment used in construction or repair work exclusive of equipment includible in other Accounts. This Account also includes the tools and accessories acquired for use with such equipment and the vehicle on which such equipment is mounted. The IOUs include these types of costs within sub-Accounts associated with Plant-In-Service (PIS), Production Plant, Accounts 312 Boiler plate equipment; 313 Engines and engine-driven equipment; 315 Accessory electric equipment; 335 Miscellaneous power plant equipment; 336 Road, railroads and bridges; 344 Generators; and 346 Miscellaneous power plant equipment. Each is functionalized to Production. Therefore, functionalizing Account 396, Power Operated Equipment (General Plant), using the PTD ratio, would overestimate the Production costs for the calculation of a utility's ASC.

Decision

BPA will functionalize Account 396, Operated Equipment (General Plant), using the TD ratio.

4.3.8 Gain and Loss from Disposition of Utility Plant (Accounts 411.6 and 411.7)

Issue

Whether Account 411.6, Gain from Disposition of Utility Plant, and Account 411.7, Loss from Disposition of Utility Plant, should be functionalized by direct analysis.

Parties' Positions

PPC/NRU state that these FERC Form 1 income Accounts should also be subject to Direct Analysis, because some of this income may be reasonably attributable to generation. (PPC/NRU, ASC0006 at 14.)

BPA's Position

In the proposed ASCM, BPA functionalized Accounts 411.6, Gain from Disposition of Utility Plant, and Account 411.7, Loss from Disposition of Utility Plant, to Distribution/Other.

Evaluation of Positions

As defined by the FERC System of Accounts, Account 411.6 shall include, as approved by the Commission, amounts relating to gains from the disposition of future use utility plant including amounts which were previously recorded in and transferred from Account 105, Electric Plant Held for Future Use, under the provisions of paragraphs B, C, and D thereof. *See* FERC Part 101—Uniform System Of Accounts Prescribed For Public Utilities And Licensees Subject To The Provisions Of The Federal Power Act. The utility shall record in this Account gains resulting from the settlement of asset retirement obligations related to utility plant in accordance with the Accounting prescribed in General Instruction 25. Account 411.7 shall include, as approved by the Commission, amounts relating to losses from the disposition of future use utility plant including amounts which were previously recorded in and transferred from Account 105, Electric Plant Held for Future Use, under the provisions of paragraphs B, C, and D thereof. The foregoing supports PPC/NRU's proposal.

Decision

BPA will require functionalization of both Accounts 411.6, Gain from Disposition of Utility Plant, and Account 411.7, Loss from Disposition of Utility Plant, by Direct Analysis with a default functionalization for Account 411.6 to Production and a default for Account 411.7 to Distribution/Other.

4.3.9 Requirement (RQ) Sales for Resale (Account 447)

Issue

Whether Account 447, Requirement (RQ) Sales for Resale, should be included in ASC and other Sales (OS) for Resale should be functionalized to Production.

Parties' Positions

The IOUs argue that Requirements Service (RQ) Sales for Resale include revenue derived from firm sales for resale to requirements sale for resale customers that take service on the utility's system and for which firm system costs (both rate base and expense) are generally allocated in jurisdictional and FERC ratemaking processes. (IOU, ASC0004 at 5.) Revenues from these sales are not available to offset Production costs (as they are recovering their allocated cost) in the same way the "off-system" sales are available to offset Production-related costs. (*Id.*) RQ Sales for Resale should not be included in ASC. Other Sales (OS) for Resale should be functionalized as PROD. (*Id.*)

BPA's Position

In the proposed ASCM, BPA functionalized all Sales for Resale to Production and did not address individual statistical classifications *(i.e.,* RQ Sales for Resale).

Evaluation of Positions

The IOUs state that revenues from RQ sales are not available to offset Production costs in the same way that the "off-system" sales are available to offset Production-related costs. (IOU, ASC0004 at 5.) "RQ Sales for Resale" as defined in the FERC Form 1, page 310, is service which the supplier plans to provide on an ongoing basis (*i.e.,* the supplier includes projected load for service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its ultimate consumers. *See* FERC Form 1, page 310.

BPA agrees in part with the IOUs on this issue. BPA notes if the IOUs want to remove the costs and revenues associated with RQ sales from Sales for Resale and Purchased Power, they must also add the associated MWh from Contract System Load.

The IOUs state that Other Sales (OS) for Resale should be functionalized as Production, which is the manner in which BPA proposed to functionalize them.

Decision

BPA will continue to include Requirement (RQ) Sales for Resale and Other Sales (OS) for Resale in Account 447 and functionalize both to Production.

4.3.10 Customer Expenses (Major) (Account 908)

Issue

Whether Account 908, Customer Expenses (Major), should be included in ASC and functionalized by direct analysis.

Parties' Positions

The IOUs state that Customer Assistance is the expense Account where conservation and DSM programs are booked. (IOU, ASC0004 at 5.) Account 908, Customer Expenses (Major), includes expenses associated with conservation, and this Account should be included in ASC and functionalized by direct analysis. (*Id*.)

BPA's Position

The proposed ASCM functionalized Account 908, Customer Expenses (Major), to Distribution/Other.

Evaluation of Positions

The IOUs contend that expenses associated with the conservation and DSM programs are booked in Account 908 and should be included in ASC and functionalized by direct analysis. (IOU, ASC0004 at 5.) The FERC Uniform System of Accounts states Account 908 is to include the cost of labor, materials used and expenses incurred in providing instructions or assistance to customers, the object of which is to encourage safe, efficient and economical use of the utility's service and includes labor items such as: direct supervision of department; processing customer inquiries relating to the proper use of electric equipment, the replacement of such equipment and information related to such equipment; advice directed to customers as to how they may achieve the most efficient and safest use of electric equipment; demonstrations, exhibits, lectures, and other programs designed to instruct customers in the safe, economical or efficient use of electric service, and/or oriented toward conservation of energy; engineering and technical advice to customers, the object of which is to promote safe, efficient and economical use of the utility's service. Other items included are for Materials and Expenses including: supplies and expenses pertaining to demonstrations, exhibits, lectures, and other programs; loss in value on equipment and appliances used for customer assistance programs; office supplies and expenses; transportation, meals, and incidental expenses.

BPA believes an analysis should reflect that the expenses are in fact tied to the conservation and DSM programs. This should include all requirements for the functionalization of conservation costs as described in section *4.6. Conservation and Oregon Public Purpose Charge*. BPA agrees that Account 908, Customer Expenses (Major), should be functionalized based upon a direct analysis.

Decision

BPA will functionalize Account 908, Customer Expenses (Major), using direct analysis.

4.3.11 General Advertising Expenses (Account 930.1)

Issue

Whether the functionalization of Account 930.1, General Advertising Expenses, should be changed from BPA's proposed functionalization of Distribution/Other to Production, Transmission, and Distribution using the Labor ratio.

Parties' Positions

The IOUs argue that general advertising costs should be included in ASC and functionalized to Production, Transmission, and Distribution using the LABOR ratio. (IOU, ASC0004 at 8.) They state this is the treatment traditionally used in rate proceedings. (*Id*.)

BPA's Position

In the Proposed ASCM, BPA functionalized Account 930.1, General Advertising Expenses, to Distribution/Other.

Evaluation of Positions

According to FERC System of Accounts, Account 930.1 shall include the cost of labor, materials used, and expenses incurred in advertising and related activities, the cost of which by their content and purpose are not provided for elsewhere. Though General Advertising Expenses are considered a cost of business and in fact may be includable in an IOU's rate proceeding, there is no evidence the costs included in this Account are Production costs and therefore allowable in the ASC calculation. However, conservation related advertising and promotion costs are considered a resource cost.

Decision

The ASCM will functionalize Account 930.1, General Advertising Expenses, to Distribution/Other. However, utilities will be able to perform a direct analysis on conservation related advertising and promotion costs irrespective of the functionalization rule specified for the account in which they are included.

4.3.12 Miscellaneous General Expenses (Account 930.2)

Issue

Whether the functionalization of Account 930.2, Miscellaneous General Expenses, should be changed from BPA's proposed functionalization of Distribution/Other to Production, Transmission, and Distribution using the Labor ratio.

Parties' Positions

The IOUs argue that these costs should be included in ASC and functionalized to Production, Transmission, and Distribution using the LABOR ratio. (IOU, ASC0004 at 8.) They state that this is the treatment traditionally used in rate proceedings. (*Id.*)

BPA's Position

In the proposed ASCM, BPA functionalized Account 930.2, Miscellaneous General Expenses, to TD.

Evaluation of Positions

The FERC Uniform System of Accounts for Account 930.2 includes the cost of labor and expenses incurred in connection with the general management of the utility not provided for elsewhere. In this Account, the following cost items are included: industry association dues; contribution for conventions and meetings of the industry; research and development costs not included in other Accounts; communication service not included in other Accounts; trustee, registrar, and transfer agent fees and expenses; stockholder meeting expenses; dividend and other financial notices; printing and mailing dividend checks; director's fees and expenses; publishing and distributing annual reports to stockholders; and public notices of financial, operating and other data required by regulatory statutes.

BPA disagrees with the IOUs on this issue. The costs included in this Account are not Production in nature and therefore should not be included in ASC.

Decision

BPA will functionalize Account 930.2, Miscellaneous General Expenses, to Distribution/Other.

4.3.13 Regulatory Commission Expenses (Account 928)

Issue

Whether the functionalization for Account 928, Regulatory Commission Expenses, should be changed from BPA's proposed Distribution/Other to either direct analysis or Production; or to Transmission for Federal or PTD in the case of state regulatory fees.

Parties' Positions

The IOUs argue that Account 928 includes fees paid to FERC; FERC regulates wholesale transmission and power transactions; and Account 928 includes fees paid to the state regulatory commissions. (IOU, ASC0004 at 3-4.) The state regulatory commissions regulate utility services provided by investor-owned utilities. (*Id.*) The regulated activities include Production, Transmission and Distribution functions. (*Id.*) These regulatory fees should be included in ASC and either allocated by direct analysis or by Production and Transmission for federal, or PTD in the case of state regulatory fees. (*Id.*)

BPA's Position

In the proposed ASCM, BPA functionalized Account 928, Regulatory Commission Expenses, to Distribution.

Evaluation of Positions

FERC regulates wholesale transmission and power transactions and Account 928 includes costs paid by IOUs to FERC for

> formal cases before regulatory commissions, or other regulatory bodies, or cases in which such a body is a party, including payments made to a regulatory commission for fees assessed against the utility for pay and expenses of such commission, its officers, agents, and employees, and also including payments made to the United States for the administration of the Federal Power Act.

See FERC Uniform System of Accounts, Pt. 101, page 459.

In addition, Account 928 includes the costs associated with state regulatory commissions for some, but not all, of the exchanging IOUs. State regulatory commissions regulate utility services provided by investor-owned utilities. In the 1981 ASCM, Account 928 was functionalized to Distribution via Footnote 19, unless the utility could demonstrate that some other functionalization was appropriate. *See* 1981 Administrators ROD, Appendix C at page 3 and 6. In the 1984 ASCM, Account 928 was functionalized to Distribution.

BPA understands that expenses included in Account 928 are related to more than just the Distribution function of utilities. However, BPA does not BPA does not believe that regulatory fees and other miscellaneous taxes and fees are resource costs for purposes of ASC determination. As noted in the 1981 ASM ROD

> In my judgment it is more appropriate to functionalize expenses incurred at the retail level to distribution/other. Therefore, I have adopted a functionalization footnote (see

footnote 3) requiring that revenue taxes related to retail sales, and other items unrelated to the power supply level such as bad debt expense, be functionalized to distribution/other.[6]

Decision

BPA will functionalize expenses included in Account 928, Regulatory Expenses, to Distribution/Other.

4.3.14 Common Plant

Issue

Whether Common Plant should be included in ASC and functionalized by direct analysis.

Parties' Positions

The IOUs argue that Common Plant should be included in ASC. (IOU, ASC0004 at 8.) For example, a portion of common plant for a combined gas/electric utility should be assigned to the electric utility and should be functionalized using a direct analysis. (*Id*.) Common Plant did appear in earlier versions of the draft ASC template but appears to have been inexplicably excluded from the April 2008 draft of the ASC template. (*Id*.)

BPA's Position

BPA proposed to functionalize all common plant assets and expenses using the PTD ratio.

Evaluation of Positions

During the ASCM Reconsultation Process, BPA realized that Common Plant assets and expenses included costs related to natural gas and electric operations. BPA will require common plant be functionalized using direct analysis and only costs related to electric operations shall be included in ASC.

Decision

BPA will require that Common Plant assets and expenses require functionalization by direct analysis and will only include costs related to electric operations.

4.4 High Water Mark and ASC Determination

Issue

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[6] Administrator's ROD, 1981 ASCM at 14.

Whether and how to exclude costs of resources from exchanging COUs' ASC to be consistent with such COUs' elections to execute Regional Dialogue HWM contracts.

Parties' Positions

Snohomish states that the calculation of ASC for COUs who sign a High Water Mark (HWM) Regional Dialogue contract should be explicitly laid out in the ASC Methodology, not in the RPSA. (Snohomish, ASC0009 at 3.)

WPAG argues that there is no statutory basis for excluding a certain vintage of otherwise exchangeable resource costs based on the type of power sales contract a preference customer has with BPA. (WPAG, ASC0008 at 6.)

BPA's Position

BPA plans to offer contracts with Contract High Water Marks in them. The customer and BPA will agree that REP benefits will not be provided for resources added to meet post-FY 2006 load growth. BPA proposes to freeze the utility's eligible exchange load as of the time of the specified resources in their HWM contract, currently FY 2006.

Evaluation of Positions

WPAG states that the proposed ASCM reserves to BPA the right to modify the ASCM to accommodate the Tiered Rates Methodology finally adopted, including the ability to exclude from the ASC calculation of preference customers who sign High Water Mark ("HWM") power contracts resource costs that would otherwise be includable in their ASC. However, they also point out that the vintage of resource costs that can be included in the ASC calculation cannot be based on the type of power sales contract the preference customer has with BPA. The right to participate in the REP is statutory in nature, and cannot be conditioned on the type of contract a customer signs. There is no objection to BPA retaining the right to make appropriate changes to the ASCM. However, modifications to the ASCM must be done in a manner that is consistent with other provisions of the Regional Act. Preference customers cannot be forced to forego one statutory right in order to exercise another. In short, there is no statutory basis for excluding a certain vintage of otherwise exchangeable resource costs based on the type of power sales contract a preference customer has with BPA (WPAG, ASC0008 at 6).

BPA understands WPAG's concerns but does not believe that a utility is foregoing ones statutory right to exercise another. A CHWM contract is not a statutory right. It is a discretionary means of meeting a utility's net requirements. A utility will have the choice of a CHWM contract in which it can exchange the costs of its pre-2006 resources, or it can decline to sign such a contract in which case BPA will offer a contract later without this limitation. The latter will satisfy BPA's statutory objection to meet net requirements.

The Long-Term Regional Dialogue Policy ROD published in July 2007 outlines the tiered rates approach, and the Tiered Rates Methodology Initial Proposal Discussion Paper posted in May 2008 reflects how the Residential Exchange Program fits into that pricing construct. The costs of the Residential Exchange Program will be allocated to the Tier 1 revenue requirement. If customers were to exchange the costs of new resources added to meet load growth, this would have a similar effect on Tier 1 rates as if BPA included some of the costs of Tier 2 resources in the Tier 1 rate – a practice that customers almost uniformly oppose. Hence, in order for the tiered rates approach to work as BPA and customers intend, participating utilities cannot place the costs of their resources used to serve load growth back into the Tier 1 cost pool. A principal objective in tiering BPA's rates is to maintain the low-cost basis of the Tier 1 System Resources. This objective will be compromised if the costs of a customer's new resources are melded with the costs of Tier 1 System Resources through the Residential Exchange Program (REP).

Snohomish states that the calculation of ASC for COUs who sign a High Water Mark (HWM) Regional Dialogue contract should be explicitly laid out in the ASC Methodology, not in the RPSA (Snohomish, ASC0009 at 3). The District is concerned that the pre-October 1, 2006 timeframe for a COU to report resources as part of its ASC is unclear regarding resource replacements and that the RPSA language will unduly limit possible options. It indicates it is likely that the District will need to replace the current long-term PPAs with third party providers, stating these are not additions but replacements that maintain our load service obligations. The District believes that the mechanism for HWM ASC calculation should be included in the ASC Methodology.

BPA agrees with Snohomish that the calculation needs to be defined in the ASCM. As part of the agreement to keep resource costs that are associated with serving load growth out of the Tier 1 cost pool, the ASC Methodology must specify how that will be accomplished.

BPA recognizes the complexity involved with trying to track individual resource costs through time, especially as older resources age and starts to require major refurbishments or must be replaced. Instead of trying to keep track of all the individual resource costs, BPA is proposing the following simplified approach.

1. Determine the High Water Mark System Load
2. Determine the High Water Mark Exchangeable Load (Residential/Small Farm Load)
3. During the Average System Costs Review process the utility shall submit the data necessary to determine the fully allocated unit cost of new resources used to meet above High Water Mark load growth.
4. Calculate the utilities Total Unadjusted Contract System Cost (CSC) as described in the ASCM
5. Calculate a load growth revenue credit {(Current System Load minus High Water Mark system Load) * Unit costs from 3 above}
6. Total Exchangeable Contract System Cost = Total Unadjusted CSC minus load growth revenue credit.
7. HWM Average System Cost = Total Exchangeable Contract System Cost / High Water Mark System Load

Eligible Exchange Loads will be determined in step 2. This approach eliminates the necessity of trying to track individual resource costs and the costs of any associated replacements through time. Freezing the Eligible Exchange Loads to the resource date specified in the HWM contract and determining High Water Mark ASCs as described above reasonably achieves the policy goal of keeping the costs of resources associated with serving load growth out of the Tier 1 cost pool.

Decision

The ASCM will revenue credit a utility's Contract System Cost for load growth valued at step 3. The utilities ASC will be calculated from their total Contract System Cost divided by their High Water Mark System Load. This ASC will then be applied to the Eligible Exchange Load in step 2.

4.5 New Large Single Load

Issue

What is the proper way to determine the cost of resources used to serve New Large Single Loads?

Parties' Positions

The IOUs offer two suggestions on the question of determining the cost of resources used to serve New Large Single Loads (NLSLs). (IOU, ASC0004 at 8.) First, the IOUs suggest BPA should permit major plant additions to pre-Northwest Power Act generation facilities to be included as post-Act generation facilities. (*Id*.) Second, the IOUs suggest the term "baseload resources" as used in Endnote d should be defined as a resource that has a planned capacity factor of at least 50%. (*Id*.)

PPC/NRU suggest there are essentially two ways of determining the cost of resources used to serve NLSLs. (PPC/NRU, ASC0006 at 14-15.) First, tie the cost of serving an NLSL with resources that were in existence at the time a load was determined to be an NLSL, and track the costs of those resources over time. (*Id*.) Second, the NLSL resource cost determination should be based on the projected cost of power purchases from the wholesale market. (*Id*.)

BPA's Position

Endnote d of the proposed ASCM did not change the methodology for determining the cost of resources used to serve NLSLs from the procedures included in the 1981 ASC Methodology, Footnote 15, and the 1984 ASC Methodology, Endnote f. Although Endnote f of the 1984 ASCM prescribes a five-step procedure for determining the cost of resources used to serve NLSLs, the operative step under current conditions is paragraph 3 of Endnote f, which essentially states that the cost of resources used to serve NLSLs will be based on the fully allocated cost of all post-September 1, 1979, baseload resources and power purchase contracts greater than 5 years in duration.

Evaluation of Positions

Section 3(13) of the Northwest Power Act defines NLSL as:

> Any load associated with a new facility, an existing facility, or an expansion of an existing facility—(A) which is not contracted for, or committed to, as determined by the Administrator, by a public body, cooperative, investor-owned utility, or Federal agency customer prior to September 1, 1979, and (B) which will result in an increase in power requirements of such customer of ten average megawatts or more in any consecutive twelve-month period.

16 U.S.C. § 839a(13).

With respect to the REP, section 5(c)(7)(A) of the Act precludes ASCs from including "the cost of additional resources in an amount sufficient to serve any new large single load of the utility." 16 U.S.C. § 839c(c)(7)(A). This preclusion has been reflected in BPA's 1981 and 1984 ASCMs through a prescribed treatment contained in an ASCM footnote. This treatment was continued in the proposed 2008 ASCM. The proposed ASCM provides:

> d/ The cost of additional resources sufficient to serve any New Large Single Load (NLSL) that was not contracted for, or committed to, prior to September 1, 1979, is to be determined as follows:
>
> 1. To the extent that any NLSLs are served by dedicated resources at the cost of those resources, including applicable transmission;
>
> 2. In the amount that NLSLs are not served by dedicated resources, at BPA's New Resources (NR) rates as established from time to time pursuant to section 7(f) of the Northwest Power Act, and as applicable to the utility, and applicable BPA transmission charges if transmission costs are excluded in the determination of BPA's New Resource rate, to the extent such costs are recovered by the utility's retail rates in the applicable jurisdiction; and
>
> 3. To the extent that NLSLs are not served by dedicated resources plus the utility's purchases at the New Resource rate, the costs of such excess load shall be determined by multiplying the kilowatt-hours not served under subsections (1) and (2) above, by the cost (annual fixed plus variable cost, including an appropriate portion of general plant, administrative and general expense and other items not directly assignable) per kilowatt-hour of all baseload resources and long term power purchases (five years or more in duration), as allowed in the regulatory jurisdiction to establish retail rates during the Exchange Period, exclusive of the following resources and purchases: (a) purchases at the NR rate; (b) purchases at the PF Exchange rate, pursuant to section 5(c) of the Northwest Power Act; (c) resources sold to BPA, pursuant to section 6(c)(1) of the Northwest Power Act; (d) dedicated resources specified in endnote d(1) of this Methodology; (e) resources and purchases committed to the utility's load as of September 1, 1979, under a power requirements contract or that would have been so committed had the

utility entered into such a contract; and (f) experimental or demonstration units or purchases therefrom. Transmission needed to carry power from such generation resources or power purchases shall be priced at the average cost of transmission during the Exchange Period.

4. Any kilowatt-hours of NLSLs not met under subsection (1), (2), or (3) above will be assumed to be supplied from the most recently completed or acquired baseload resource(s) or long term power purchase(s), exclusive of dedicated resources and experimental or demonstration resources or purchases therefrom, that are committed to the utility's load as of September 1, 1979, under a power requirements contract. The cost of these generation resources and long-term power purchases and the transmission cost associated with these resources or purchases will be calculated as specified in subsection (3) above.

5. If the NLSL is served on any energy or capacity interruptive basis, the utility shall prepare a calculation subject to review by BPA of the fixed (if any) and variable costs of providing such service, except that the amount excluded from ASC for the NLSL shall not be less than the transmission and generation cost included in the retail rate charged the NLSL.

In the ASCM consultation process, BPA staff discussed its concern that, for many utilities, the resource cost determination prescribed in Endnote d could result in a cost of resources below a utility's ASC. This is because many of the resources used in the calculations were large, central station, coal-fired resources that were installed in the early 1980s. Because some of these resources are near the end of their depreciable lives, the return component is low and fuel and variable O&M are also low. Analysis prepared by BPA staff and discussed during the consultation process indicated that the fully allocated cost of Colstrip Units 3 and 4 was about $30-34/MWh and Boardman was about $34-40/MWh depending on the capacity factor of the plant. Colstrip Units 3 and 4 and Boardman are both baseload resources built in the early 1980s and would be a part of the NLSL resource cost determination for many of the IOUs. This contrasts with current wholesale market prices in the $60-80/MWh range and the fully allocated cost of gas-fired combined cycle combustion turbines (CCCTs) in the $60-65/MWh range.

For utilities that own a large quantity of baseload resources built in the early 1980s, it will be many years before the quantity and cost of new base load resources, such as CCCTs, result in an NLSL resource cost determination that is higher than the utilities' respective ASCs. If the NLSL resource cost determination is below a utility's ASC, it will result in an increase in that utility's ASC. BPA believes that increasing a utility's ASC as a result of excluding the costs of serving NLSLs is inconsistent with the intent of the NLSL provisions of the Northwest Power Act. When BPA serves a preference customer, any NLSL service is priced at BPA's NR rate, which generally reflects current incremental resource costs.

In considering the proper approach for determining the resource costs of serving NLSLs, BPA should consider the dramatic changes that have occurred in the generation area of the electric utility industry between 1981, which was when the current NLSL resource cost methodology was developed, and the present. In the early 1980s, most utilities developed large, coal-fired, central station baseload power plants to meet their customers' requirements. That environment stands in stark contrast to current conditions where concerns over emissions and rapidly escalating costs of all carbon-based fuels have caused utilities to diversify their resource portfolios to include a large share of renewable resources (such as wind) and purchases of electricity from the wholesale market. BPA believes the NLSL resource cost determination must reflect the current types of resources acquired by exchanging utilities.

BPA proposes to include <u>all</u> post September 1, 1979, generating resources in the determination of the cost of resources used to serve NLSLs to better reflect the diversity of generating resources exchanging utilities use to meet the requirements of meeting their customers' energy requirements. Review of any current integrated resource plan or similar document prepared by a regional utility would clearly show that relying on base load generating resources for NLSL resource cost determinations is out of touch with modern generating resource portfolios.

Parties have suggested a number of approaches for determining the cost of resources used to serve NLSLs. As noted above, the IOUs suggest that major plant additions to pre-Northwest Power Act generation facilities should be included as post-Act generation facilities. (IOU, ASC0004 at 8.) BPA does not support the IOUs' position that allows major upgrades or investments in pre-September 1, 1979, resources because it would add needless complexity and contention to the ASC review process with arguments over what constitutes a "major" upgrade or whether the relicensing of a hydro project changes anything other than the date which the owner must again relicense the project. By the same rationale, BPA cannot support PPC/NRU's position that the resource cost determination should be based on "vintage" resources in place when a load was determined to be an NLSL. Again, BPA believes that this would create a record-keeping burden on the filing utilities, BPA and parties to the ASC review process because of the need to track the cost of individual resources and any replacements, upgrades and other modifications for the life of the NLSL.

The IOUs also suggest the term "baseload resources" as used in Endnote d be defined as a resource that has a planned capacity factor of at least 50 percent. (IOU, ASC0004 at 8.) Because BPA will eliminate the term "baseload" from the description of resources used to serve NLSLs, this point is moot.

As an alternative to "vintage" the cost of resources in place when the load was determined to be a NLSL, PPC/NRU suggest that BPA should tie the cost of serving an NLSL with wholesale electricity market prices. (PPC/NRU, ASC0006 at 15.) Although BPA acknowledges the administrative ease and simplicity of PPC/NRU's suggestion to use wholesale market prices as the cost of resources used to serve NLSLs, such an approach would be too restrictive. Section 5(c)(7)(A) of the Northwest Power Act precludes ASCs from including "the cost of additional resources in an amount sufficient to serve any new large single load of the utility." 16 U.S.C. § 839c(c)(7)(A). Thus, NLSL resource cost determinations should reflect the incremental cost of the *resources* attributed to serving a utility's NLSL. BPA believes that use of only power purchases would improperly limit the types of resources used to determine the cost of serving NLSLs.

The IOUs also suggest the term "baseload resources" as used in Endnote d be defined as a resource that has a planned capacity factor of at least 50 percent. (IOU, ASC0004 at 8.) Because BPA will eliminate the term "baseload" from the description of resources used to serve NLSLs, this point is moot.

The IOUS also suggest the following three changes:

1. The amount of any NLSL served by a utility is and should be the load of the facility on the utility net of the customer's own generation (rather than the gross facility load).

2. NLSL determinations should be based on the gross facility load.

3. Decreases in generation behind the meter should not result in loads becoming NLSLs if such loads would not have been NLSLs in the absence of such generation. For example, if a large facility that is not an NLSL installs generation that reduces its net load to the utility by 10 or more aMWs, then removing the generator or not operating the generator or selling the output or the generator should not trigger NLSL status.

The three foregoing comments address BPA's NLSL Policy, not the determination of resource costs used to serve NLSLs for ASC purposes. BPA has already addressed similar issues in past reviews of its NLSL Policy or addressed them in the 1981 contract record. BPA is not currently proposing any changes to its NLSL Policy. NLSLs are determined for all customers under the NLSL Policy, not the ASC Methodology. BPA does not intend to change that alignment of policies.

Decision

BPA will determine the cost of serving NLSLs by using the fully allocated cost of all post-September 1, 1979, resources and long-term power purchases of greater than one year in duration. Because wind resources comprise an increasingly larger share of exchanging utilities' resource portfolios, and many utilities may be acquiring more wind resources than carbon fueled resources, the ASCM is eliminating the requirement that a resource must be a baseload resource to be included in the NLSL resource cost determination. In addition, a utility's ASC will not increase as a result of excluding the costs of resources used to serve NLSLs.

4.6 Conservation and Oregon Public Purpose Charge

4.6.1 Conservation Data

Issue

Whether BPA should allow COUs the flexibility to provide conservation data using their own internal accounting methods that track the conservation expenditures associated with actual conservation achievements.

Parties' Positions

Snohomish states BPA should allow COUs the flexibility to provide conservation data using their own internal accounting methods that track the conservation expenditures associated with actual conservation achievements. (SNOHOMISH, ASC0009 at 1-2.) Compared to the IOUs, COUs may account for conservation investments via internal project coding, rather than by FERC account. (*Id.*) This has been the practice for many years and has provided Snohomish with an effective means by which to track and monitor program costs. (*Id.*) These costs are easily identifiable and verifiable by Snohomish through the Appendix 1 filing process. (*Id.*) BPA must allow these project-coding costs to be included in Snohomish's conservation costs before the functionalization breakout. (*Id.*) This treatment would provide an ASC calculation that is consistent with other exchanging IOUs. (*Id.*)

BPA's Position

While BPA did not specifically address this issue in the Proposed ASCM, it recognized that COUs do not file FERC Form 1s and was fully prepared to adjust the requirements of the ASC template and filing requirements to adapt to the COUs accounting systems for the recording of conservation costs.

Evaluation of Positions

Snohomish argues BPA should consider a conservation functionalization ratio of 90/10 rather than 70/30 to more accurately reflect the expenditures that are allowable conservation costs. (SNOHOMISH, ASC0009 at 1 & 2.) Conservation investments made by Snohomish, relative to conservation education and other public purpose expenditures, differs from the proposed BPA functionalization allocation, that was determined based upon a review of the Oregon Public Purpose Charge. (*Id.*) BPA has proposed a 70/30 split between actual conservation investments and financial amounts spent for conservation education and other public purpose objectives. (*Id.*) The 70/30 split does not allow Snohomish to reflect its actual, documented conservation expenditures. (*Id.*) The 90/10 ratio more accurately reflects Snohomish's conservation expenditures that should be included in ASC production costs. (*Id.*)

BPA agrees that conservation functionalization ratio of 70% to Production and 30% to distribution (70/30) does not accurately reflect the functional nature of Snohomish's conservation expenditures, or any other exchanging Utility for that matter. The 70/30 ratio was included as a placeholder until BPA could gather additional information on the types of conservation programs in existence at exchanging utilities through the ASCM Reconsultation process and discussions with organizations such as the Energy Trust of Oregon (ETO). BPA now believes that use of any ratio is inappropriate to functionalize conservation program costs because of the diverse way in which regional Utilities, state commissions, state and local governments and PUD boards acquire conservation resources and implement conservation programs. For example, the Oregon legislature took PGE and Pacific completely out of the conservation acquisition and program development process by creating the ETO. PGE and Pacific fund the ETO activities through a public purpose charge equal to 3% of retail sales of electricity for IOUs only. In contrast, Washington funds conservation programs through Tariff Riders to fund individual programs. Montana levies a Universal System Benefit charge similar to Oregon, but levies it on all retail sales of electricity, but many of the conservation programs are delivered by the utilities.

Decision

BPA will no longer use ratios to functionalize conservation program costs or revenues sent to organizations like the ETO who perform conservation programs for utilities. BPA will examine conservation program costs and public purpose charges on a utility-by-utility basis. The ASCM will only allow the costs of conservation measures that reduce consumption of electric energy and energy audits used to ensure successful implementation and delivery of conservation programs.

4.6.2 Functionalization of OPPC

Issue

Whether the Oregon Public Purpose Charge (OPPC) should be functionalized 100 percent to Production.

Parties' Positions

The IOUs support functionalization of 100% of the OPPC in Production. In addition they support inclusion of the Montana Universal Systems Benefit Charge to Production. (IOU, ASC0004 at 6.) The WUTC also supports inclusion of the OPPC in ASC and also argues that conservation related "tariff riders" also be allowed as an allowable cost in ASC. (WUTC, ASC005 at 11.) Similarly, the OPUC argues that 95.5% of the OPPC charge be functionalized to Production. (OPUC, ASC0010 at 6-9) PPC/NRU, WPAG and PRC all argue that 63% of OPPC funds should be allocated to Production and 37% should be allocated to Distribution/Other. (PPC/NRU, at 6-9.) (WPAG, at 2.) (PRC at 3.)

BPA's Position

The Proposed ASCM functionalizes 70% of OPPC to Production and 30% to Distribution/Other.

Evaluation of Positions

Oregon's Public Purpose Charge (OPPC) was established in 1999 with passage of Oregon's electricity restructuring law, Senate Bill 1149. *See generally,* Or. Rev. Stat. § 757.612 (2005). The OPPC was established to ''fund new cost effective local energy conservation, new market transformation efforts, the above-market costs of renewable energy resources and new low income weatherization.'' *Id.* at § 757.612(2)(a). The OPPC is set at 3 percent of total retail sales of electricity for PacifiCorp-Oregon, Portland General Electric (PGE) and Idaho Power-Oregon. *Id.* The OPPC applies to COUs only if they allow direct access to any class of their customers. *Id.*

At this time, BPA is not aware of any consumer-owned utilities that are participating in the OPPC program. The OPPC replaces the conservation/DSM programs PGE, PacifiCorp-Oregon and Idaho Power-Oregon operated before Oregon SB 1149. When the OPPC was implemented by the utilities, the OPUC was directed to remove the costs of OPPC-like programs from retail rates. *Id.* at § 757.612(3)(g). The OPPC was implemented on March 1, 2002, for PGE and PacifiCorp- Oregon, and in 2006 for Idaho

Power- Oregon. Distribution of the OPPC funds are made monthly by the utilities to the following organizations in the following percentages: Energy Trust of Oregon (ETO) -73.8% Education Service Districts (ESD) - 10.0% Oregon Housing and Community Services (OHCS) - 16.2%. PGE, PacifiCorp and Idaho Power do not show the OPPC on their financial statements or Form 1s. The utilities treat the revenue and expense as a direct pass-through. Accounting records are available from the utilities showing the revenue received and the payments made to the three recipient organizations.

SB 1149 states that the OPPC funds are allocated in the following manner: New cost-effective conservation and market transformation - 63%, above market cost of renewable energy resources - 19% Low-income weatherization - 13%, Low-income bill payment assistance - 5%. The 1981 and the 1984 ASC Methodologies did not address the cost treatment of charges like the OPPC. A key attribute of the OPPC has been that it effectively replaces the Utility's conservation program, which is typically included as part of a Utility's base rates. Because of this unique feature, BPA proposes that the OPPC is an alternative form of acquiring conservation and renewable resources, and therefore should be considered in determining ASC. In the same way that some utilities build thermal resources and others purchase power from the market; the OPPC is a similar method of acquiring conservation and renewable resources.

Another way of looking at the OPPC is as an outsourcing arrangement. While some utilities have their own conservation departments and programs, Oregon investor-owned Utilities are effectively required to ''outsource'' their conservation activities to the ETO, OHCS and ESDs. BPA needs to have the right to review and audit the costs and programs of the organizations that receive OPPC funds in order to determine the portion of the Utility's costs that are excludable from their ASC. If an OPPC-recipient organization denies BPA the right to review and audit its costs and programs, then BPA will not include such costs in the Utility's ASC calculation. BPA will review the OPPC costs and functionalize the costs using the same procedure as used in reviewing Utility conservation costs.

The Energy Conservation Charge was approved at the OPUC January 22 Public Meeting, Advice No. 07-022. (IOU, ASC0004 at 6.) The original public purpose charge is currently functionalized by a 70%/30% specific functionalization ratio determined by BPA resulting from discussions with the Oregon Energy Trust. *Id.* This split may change depending on future discussions; however, the new public purpose charges are entirely for conservation measures, and therefore, should be functionalized 100% to Production. *Id.*

The OPUC supports BPA's proposal to treat costs for OPPC related to the acquisition of conservation and renewable resources consistently with conservation costs incurred by utilities in other jurisdictions. *Id.* As BPA notes in its FRN, the OPPC replaces the conservation/DSM programs PGE and PacifiCorp-Oregon operated before creation of the OPPC. *Id.* Accordingly, OPPC costs associated with the acquisition of conservation and renewable resources should be included in the ASCs of PGE and PacifiCorp-Oregon. *Id.* The OPUC believes that 95.5 % of the OPPC is properly includable in ASC under BPA's proposed treatment. *Id.* The uses to which the OPPC may be put are defined in statute. *Id.* With the exception of money that is allocated to the Housing and Community Services Department in Oregon (4.5%), the money collected under the OPPC *must* be spent on programs like those administered by other utilities, or BPA itself, and which are exchangeable. *Id.* More specifically, the OPPC is spent on cost-effective conservation, new market transformation, renewable energy resources, low-income weatherization, and various conservation activities by ESDs. *Id.*

The WUTC argues that under Oregon law, utilities in that state no longer operate their own conservation programs. (WUTC, ASC005 at 14.) Instead, they secure conservation resources through third-party agencies, which are funded by a charge on utility customer bills. The utilities treat the revenue and expense as a direct pass-through, which is not entered on the FERC Form 1. *Id.* BPA is proposing to include these public purpose charge revenues as expenses in ASC as a substitute for what the utilities operating in Oregon would otherwise have expended to secure the conservation resources, consistent with the resource priorities in the NWPA. Because of the unique circumstances surrounding this item, this treatment is appropriate. *Id.*

PPC/NRU, WPAG and PRC all argue that 63% of OPPC funds should be allocated to Production and 37% should be allocated to Distribution/Other. (PPC/NRU, at 6-9.) (WPAG, at 2.) (PRC at 3.) PPC/NRU, WPAG and PRC all argue BPA may not have the authority to audit the recipients of funds from the OPPC, which are not IOUs, but are instead the Energy Trust of Oregon, Education Service Districts, and the Oregon Department of Housing and Community Services. PPC/NRU, at 6-9.) (WPAG, at 2.) (PRC at 3.)

BPA concedes that it may not have the right to 'audit' the programs of the OPPC recipient organizations in the strict use of the word audit. But BPA is confident that it will be able to thoroughly review the programs, budgets and records of the OPPC recipient organizations with the same rigor that it applies to ASC filings of exchanging Utilities. If BPA is not allowed to review the data of an OPPC recipient organization, or any other organization that receives funds from an exchanging Utility that includes those funds in an ASC filing, BPA has the authority to disallow those costs.

PPC/NRU, WPAG and PRC all argue that they are not clear what standards BPA's auditors would use to determine what is an "allowable" expense for the purposes of the ASC Methodology. (PPC/NRU, at 6-9.) (WPAG, at 2.) (PRC at 3.)

BPA will apply the same review standards to all conservation program costs irrespective of whether they are Utility run programs or programs run by the ETO or similar organizations. The costs included in the ASC filing have to be allowable conservation costs under the ASCM.

Further, PPC/NRU, WPAG and PRC all argue that BPA should functionalize 63% of conservation costs to Production and 37% to Distribution other because not all of OPPC programs are cost-effective conservation programs. (PPC/NRU, at 6-9.) (WPAG, at 2.) (PRC at 3.)

BPA agrees that conservation functionalization ratio of 70% to Production and 30% to distribution (70/30) does not accurately reflect the functional nature of OPPC conservation, or any other exchanging Utility conservation program or public purpose charge for that matter. The 70/30 ratio was included as a placeholder until BPA could gather additional information on the types of conservation programs in existence at exchanging utilities through the ASCM Reconsultation process and discussions with organizations such as the Energy Trust of Oregon (ETO).

BPA now believes that use of any ratio is inappropriate to functionalize conservation program costs because of the diverse way in which regional Utilities, state commissions, state and local governments and PUD boards acquire conservation resources and implement conservation programs. For example, the Oregon legislature took PGE and Pacific completely out of the conservation acquisition and program development process by creating the ETO. PGE and Pacific fund the ETO activities through a public purpose charge equal to 3% of retail sales of electricity for IOUs only. In contrast, Washington funds conservation programs through Tariff Riders to fund individual programs. Montana levies a Universal System Benefit charge similar to Oregon, but levies it on all retail sales of electricity, but many of the conservation programs are delivered by the utilities.

Decision

BPA will no longer use ratios to functionalize conservation program costs or revenues sent to organizations like the ETO who perform conservation programs for utilities. BPA will examine conservation program costs, costs related to acquisition of renewable resources, low-income weatherization programs and other such programs funded by public purpose charges on a utility-by-utility basis.

4.6.3 Advertising and Promotion Costs

Issue

Whether BPA should include the cost of advertising and promoting energy conservation programs in ASC to the same extent such costs are included in BPA's own firm power rates.

Parties' Positions

The WUTC argues that the costs of advertising and promotion related to conservation should be treated as an allowable conservation expense for determination of ASC. (WUTC, ASC0005 at 11-12.)

BPA's Position

BPA's proposed ASCM excluded the cost of conservation related advertising and promotion expenses from determination of ASC.

Evaluation of Positions

BPA proposed to exclude advertising costs related to conservation from ASC. The 1984 ASCM ROD stated that the Administrator will determine what conservation costs are allowable in ASC. Of necessity, these determinations must be case specific, based on the information provided by the exchanging utility in its ASC filing. 1984 ASCM ROD at 72. In addition, the 1984 ASCM Rod stated that Conservation A&G expenses will be limited to only those expenses relating to conservation measures for which power is saved by physical improvements or devices. Advertising, promotion, and audit expenses are not resource costs and therefore are not includable in the ASC. *Id*.

We are not aware that BPA separates its own conservation program expenditures so that advertising and promotion are excluded in the calculation of BPA's firm power rates – either the Preference Firm or Preference Firm Exchange rate. (WUTC, at 12.) Just as we argued for symmetry in the treatment of transmission costs, we recommend that BPA seek symmetry in the treatment of total conservation costs (including the cost of advertising and promoting these programs) by including these costs in the calculation of ASC. *Id.*

BPA agrees with the WUTC that conservation-related advertising cost should be treated as an allowable cost in the determination of ASC. BPA agrees that advertising is an important component of conservation programs, especially when it comes to market transformation activities for changing consumer behavior. This especially true given the large amount of conservation utilities will be required to acquire in the future. The FERC Form 1 data do not distinguish or identify the specific purpose or intent of advertising and promotion costs. BPA cannot tell from the Form 1 whether advertising costs are related to conservation or are image building or branding. Utilities that wish to include conservation related advertising expenses in their Base ASC Filings will be permitted to do so by performing a Direct Analysis on their advertising related expenses. The direct analysis must show in a clear and convincing fashion that the costs are truly related to conservation activities. Advertising and promotion that is image building or branding will not be allowed. BPA will make the determination of what constitutes conservation related advertising expenses.

Decision

BPA will allow conservation related advertising and promotion costs in the determination of ASC based on a detailed Direct Analysis submitted by the Utility in its Base ASC Filing. All other advertising and promotion costs will be functionalized to Distribution/Other.

4.6.4 Tariff Riders Treatment

Issue

Whether BPA should include amounts collected by Washington utilities through "tariff riders" to accomplish conservation programs as an allowable cost in ASC, regardless of whether these amounts appear on the FERC Form 1 and regardless of whether the conservation programs are delivered by the utility or a third party.

Parties' Positions

WUTC argues that BPA should include "tariff riders" for conservation programs in a manner similar to treatment of OPPC. (WUTC, ASC0005 at 13-14.)

BPA's Position

BPA did not address this issue in the Proposed ASCM.

Evaluation of Positions

BPA proposes to include in ASC the revenue generated by Oregon's "public purpose charge," which revenue is administered to achieve conservation by the Energy Trust of Oregon, Oregon Educational Service Districts and Oregon Housing and Community Services. *Id.*

Under Oregon law, utilities in that state no longer operate their own conservation programs. Instead, they secure conservation resources through third-party agencies, which are funded by a charge on utility customer bills. *Id.* The utilities treat the revenue and expense as a direct pass-through, which is not entered on the FERC Form 1. *Id.*

BPA is proposing to include these public purpose charge revenues as expenses in ASC as a substitute for what the utilities operating in Oregon would otherwise have expended to secure the conservation resources, consistent with the resource priorities in the NWPA. *Id.* Because of the unique circumstances surrounding this item, this treatment is appropriate. *Id.*

By the same token, a similar situation may exist when utilities use tariff "riders" that establish a funding source for conservation programs. *Id.* For example, Puget Sound Energy, Avista and PacifiCorp all use tariff riders to fund their conservation programs in Washington. Consequently, BPA should accord similar ASC treatment of these revenues if they are not reported on the FERC Form 1. *Id.*

BPA disagrees. Based on BPA's review of "tariff riders" for Washington Utilities, almost all of them were to fund Utility sponsored conservation programs. The costs of Utility conservation programs are included on the FERC Form 1 as evidenced by Utility and WUTC comments on inclusion of various conservation program costs in ASC in other parts of this document. The situation in Oregon with the OPPC is unique. Oregon Utilities no longer operate conservation programs. In essence they have been "outsourced" to OPPC recipient organizations and no conservation related costs are included PGE's FERC Form 1 and for the Oregon portion of PacifiCorp's FERC Form 1. What the WUTC is asking for is to "double count" conservation costs; once when the tariff rider revenue is included as an expense on the Utility ASC filing, and again through the inclusion of conservation program costs from the Utility FERC Form 1.

Decision

BPA will not allow the inclusion of 'Tariff rider' revenue as an expense in utility ASC filings.

4.7 Rate of Return

Issue

What is the appropriate rate of return for inclusion in ASC?

Parties' Positions

The WUTC, OPUC and IPUC all support inclusion of equity return in the determination of exchanging utilities' ASCs. (WUTC, ASC0005 at 14-19; OPUC, ASC0010 at 5; IPUC, ASC0003 at 8.) Inclusion of equity in the IOUs' capital structures serves to reduce the IOUs' costs of debt. (WUTC, ASC0005 at 16.) If IOUs were 100 percent debt financed they would be at greater risk of default, which would result in a significant increase in their cost of debt. (*Id*.)

WPAG opposes including return on equity in ASC because determination of the rate of return on common equity by state regulatory commissions is a subjective exercise and conditions which gave rise to inclusion of the cost of terminated plants through manipulation of return on equity (ROE) could recur under BPA's proposed ASCM. (WPAG, ASC0008 at 4-5.)

PPC/NRU oppose inclusion of return on equity in ASC because of the risk of including the costs of terminated plants in ASC; the potential for manipulation of ROE to increase ASC; the potential for the costs of subsidiary or parent companies to be improperly included in ASC; and because BPA's reliance on state commission orders could overstate ROEs in periods of declining capital markets, thus overstating ASCs. (PPC/NRU, ASC0006 at 8-10.)

Even though PRC supports the comments provided by PPC/NRU, it also states that in the event that BPA is successful in its effort to re-introduce ROE into the ASC Methodology, it believes COUs should be allowed to include an ROE in the same manner that BPA is currently proposing for IOUs. (PRC, ASC0001 at 1-2).

BPA's Position

The proposed ASCM allows ROE in ASC based upon a Utility's most recent ROE approved by the Regulatory Body. For purposes of determining return on rate base, the Utility will include the weighted cost of capital from its most recent rate order. For Utilities with service territories in more than one state, the Utility will submit a weighted cost of capital based on its most recent Regulatory Body rate orders, weighted by rate base in states within the Pacific Northwest region. For COUs, the return component will equal the weighted cost of debt times the rate base in the ASC filing.

Evaluation of Positions

In the Federal Register Notice for the proposed 1984 ASC Methodology, BPA stated that "in developing an ASC methodology the BPA Administrator has considerable discretion in deciding whether to permit inclusion of an equity return allowance and, if so, how that component is to be determined." 49 Fed. Reg. 4230, 4235 (Feb. 3. 1984). The Administrator's discretion was affirmed by FERC in its order approving the 1984 ASC Methodology:

> Congress chose the Administrator to determine cost of utility resources. Had the Congress intended that the Administrator must follow State commission determinations of a utility's resource costs, it could have easily included this requirement in the statute or simply left the Administrator out altogether and let the State commissions develop the ASC methodology. This was not done. The Administrator was chosen to develop a methodology to determine ASC, subject only to the Commission's review.

49 Fed. Reg. 39,293, 39,296 (Oct. 5, 1984). In the 1984 ASC Methodology, BPA excluded the cost of equity from ASC primarily because of concern that Regulatory Bodies might increase the allowed ROE to compensate Utilities for the cost of terminated plants. In one case, terminated plant costs were removed from an ASC filing during BPA review. *See* BPA's Average System Cost Report for Portland General Electric Company, Jurisdiction: Oregon (May 13, 1983). Because a Utility had attempted to unlawfully include terminated plant costs in its retail rates and its ASC, which was effectuated by the Public Utility Commissioner allowing a higher return on equity, BPA wanted to revise the ASC Methodology to prevent future abuse. BPA's remedy was severe, limiting a Utility's return to the long-term cost of debt. On review, the Ninth Circuit conditionally affirmed BPA's exclusion of ROE from ASC based on BPA's experience with implementing the program and its need to avoid abuses. *PacifiCorp v. F.E.R.C.*, 795 F.2d 816, 823 (9th Cir. 1986). In making this finding, however, the Court did not "sanction any permanent implementation of these exclusions." *Id*. at 823.

The 1984 ASC Methodology did not allow ROE in ASCs, but instead determined a Utility's return on rate base for ASC purposes through use of a Utility's long-term cost of debt. BPA now proposes that ROE should be included in ASC. The cost of debt is a cost of resources and, in the case of investor-owned utilities, the cost of debt is lowered by the contribution of equity by the company. Without spreading risk to shareholders there would be a significant increase in the cost of debt. State commissions and rating agencies require investor-owned utilities to maintain specific capital structures that affect the company's debt ratings. Therefore, debt alone is not an adequate reflection of the capital cost of a Utility's resources. Without an equity component in the cost of capital, a higher cost of debt is needed to reflect the true cost of financing resources.

Enough changes have occurred in the regional regulatory environment to reasonably ensure that terminated plant costs will not be included with allowable costs under the ASC Methodology. First, the costs of the Pebble Springs nuclear plant that were the basis of the terminated plant controversy in the mid-1980s have been completely written off by the utilities involved. Second, Oregon's establishment of a three-person appointed public utility commission greatly reduces the chance of improper communications between the OPUC and utilities. Third, since 1984, Oregon has had a Citizens' Utility Board (CUB), which monitors the retail rate development of utilities conducting business in Oregon. CUB reviews retail rates in order to ensure, among other things that terminated plant costs are excluded from such rates. In addition, increased disclosure and filing requirements at the commission level make identifying inappropriate costs much easier. All four state commissions now require utilities under their review to prepare Integrated Resource Plans (IRP). Although approval or acknowledgement of IRPs does not assure that resources included in the IRP will be allowed in rate base if constructed, the IRP process greatly reduces the probability of terminated plants. Thus, the risk that Regulatory Bodies will include inappropriate costs in the ROE has diminished significantly since 1984.

Because of these changes, and based on BPA's experience in implementing the ASCM, BPA now proposes that Utilities should be allowed to exchange ROE at a Utility's most recent commission-approved level. For purposes of determining return on rate base, the Utility will include the weighted cost of capital from its most recent rate order. For Utilities with service territories in more than one state, the Utility will submit a weighted cost of capital based on the most recent Regulatory Body rate orders weighted by rate base in states within the PNW region.

The IPUC strongly supports inclusion of equity return in the proposed ASCM. (IPUC, ASC0003 at 8.) The current exclusion of this cost in the 1984 ASC Methodology fails to recognize the very real impact that an IOU's capital structure has upon its operating and capital costs. (*Id.*) The cost of common equity in an IOU's capital structure results in a reduction of the company's cost of debt. (*Id.)* The 1984 ASCM took advantage of the lower cost of debt in a typical IOU capital structure by failing to include the cost of that equity. (*Id.*) The proposed change to include ROE in the new ASCM corrects this deficiency in the 1984 ASCM. (*Id.*) The original concerns that led to excluding ROE costs either no longer exist or are adequately addressed by other regulatory bodies. (*Id.*)

The WUTC strongly supports BPA's proposal to include ROE as an allowable cost component in ASC. (WUTC, ASC0005 at 14.) The WUTC supports BPA's proposal to allow return on equity as most recently approved by a state utility regulatory commission(s). (*Id.*) For multi-state utilities, the WUTC supports BPA's proposal to allow return on equity in ASC as the average of most recent costs-of-capital approved by the state utility commission(s), weighted by the rate base in the states located in the Pacific Northwest region. (*Id.*) Return on equity is an inseparable component of the cost an investor-owned utility (and its customers) bears to finance and own the power resources it needs to serve its qualifying residential and small farm loads. (*Id.*) Accordingly, cost of equity is a resource cost and it should be included in ASC as such. (*Id.* at 15.) Obviously, investor-owned utilities must raise the capital necessary to build and own power facilities, and investors supply this capital in two basic forms: debt and common equity. (*Id.*)

The WUTC states it is a long recognized principle of finance in general, and utility finance in particular, that the appropriate mix of these sources of capital (generally referred to as the capital structure) achieves the lowest cost when the concepts of investor "safety" and cost "economy" are balanced. (*Id.*) "Economy" refers to the cost of the financing. (*Id.*) Debt generally has a lower cost than common equity. (*Id.*) "Safety" refers to the security of the financing. (*Id.*) A highly leveraged capital structure is less safe because the risk of default is higher. (*Id.*) Equity generally costs more than debt because its returns are not guaranteed and its repayment is secondary to debt in the event of bankruptcy. (*Id.*) However, for an investor-owned utility, equity investment provides the security (safety) necessary to achieve a balanced capital structure and to secure the lowest reasonable debt cost. (*Id.*)

The WUTC notes, for example, that for an investor-owned utility, a capital structure containing 100 percent debt would be unsafe and would have very high cost. (*Id.*) Debt rating agencies such as Standard & Poors (S&P) likely would rate that debt as below investment grade and investors would accordingly demand a very high risk-premium. (*Id.* at 16.) By contrast, a capital structure approaching 100 percent equity would have very low leverage, very high security and maximum safety for debt holders. (*Id.*) However, such a capital structure would also be very expensive because the low cost of debt in the capital structure would be more than offset by the much higher cost of the equity. (*Id.*) An appropriate capital structure balances the economy of the low cost of debt with the safety provided by equity. (*Id.*) The WUTC states and BPA acknowledges this relationship between debt and equity in its 2007 ASCM proposal, saying "without an equity component in the cost of capital, a higher cost of debt is needed to reflect the true cost of financing resources." (*Id.*) BPA's proposed ASCM correctly includes return on equity as an indivisible component of the cost of capital that investor-owned utilities must pay in order to finance resources included in its average system cost. (*Id.*) Nothing in the Northwest Power Act precludes BPA from including the true cost of financing resources in the ASCM. (*Id.*) Moreover, both FERC and the Ninth Circuit Court of Appeals have found that the BPA Administrator has the authority to exercise discretion in determining an ASCM. (*Id.*) Indeed, the objective of the exchange provision in section 5(c) of the Act is to allow the residential and small farm customers to share in the economic benefits of the lower cost federal resources marketed by BPA. (*Id.*) Their rightful share of those benefits is based on the utility's resource costs, or ASC. (*Id.*)

The WUTC states that a reasonable measurement of the utility's ASC must accurately reflect the cost of the capital that financed the utility's resources. (*Id.*) For an investor-owned utility, the cost of equity capital is no less a cost of financing a utility resource than the cost of debt capital. (*Id.*) It is therefore improper for BPA's ASCM to continue to ignore the cost of equity, and base financing costs solely on the cost of long-term debt. (*Id.*) The cost of equity and the cost of debt are inextricably interrelated because an investor-owned utility cannot obtain debt capital unless it has a balanced capital structure that includes equity capital. (*Id.*) Nothing in the Northwest Power Act requires, or specifically authorizes, BPA to treat investor-owned utilities like public (or preference) utilities, who are able to finance resources without issuing common equity, or who can obtain government-secured debt by financing resource development through BPA. (*Id.*) Including the cost of equity results in a more accurate ASC calculation, thereby enhancing the BPA Administrator's ability to manage the true cost of the resources purchased under the exchange program. *(Id.)* Section 5(c)(5) allows BPA ample flexibility to manage these costs when necessary by purchasing a less expensive resource "in lieu" of purchasing resources at an exchanging utility's accurately determined ASC. *Id.*

The WUTC notes that while some may assert that including the cost of equity *may* present problems related to abandoned plant, "black-box" settlements or "stale" data, these arguments go to BPA's <u>review</u> of these costs; they are not reasons to exclude entirely what is clearly a legitimate and necessary cost of power resources. (*Id.*) For example, there are other means for BPA to ensure that the cost of terminated power plants is not included in a utility's ASC. (*Id.* at 19.) Terminated plants are readily identifiable. (*Id.*) BPA's review of any utility's ASC filings would allow it to make adjustments to ASC components as appropriate on a case-by-case basis. (*Id.*) If the cost of equity is found to reflect terminated plant, BPA can determine the impact on cost of equity and make an appropriate adjustment. (*Id.*)

WPAG argues that because determination of the rate of return on common equity by state regulatory commissions is a subjective exercise, conditions which gave rise to inclusion of the cost of terminated plants through manipulation of ROE could recur under BPA's proposed ASCM. (WPAG, ASC0008 at 4.) BPA disagrees with WPAG that the conditions that allowed terminated plant in ROE could easily recur in the current regulatory environment. As noted above, enough changes have occurred in the Pacific Northwest regulatory environment to reasonably ensure that terminated plant costs will not be included with allowable costs under the ASC Methodology. First, the costs of the Pebble Springs nuclear plant that were the basis of the terminated plant controversy in the mid-1980s have been completely written off by the utilities involved. Second, Oregon's establishment of a three-person appointed public utility commission greatly reduces the chance of improper communications between the Oregon PUC and utilities. Third, since 1984, Oregon has had a Citizens' Utility Board (CUB), which monitors the retail rate development of utilities conducting business in Oregon. CUB reviews retail rates in order to ensure, among other things that terminated plant costs are excluded from such rates. Additionally, increased disclosure and filing requirements at the commission level make identifying inappropriate costs much easier. All four state commissions now have requirements that utilities under their review prepare Integrated Resource Plans. From these filings, BPA and its customers can likely determine if a Utility included the costs of terminated plant in its equity calculation. Thus, the risk that Regulatory Bodies will include inappropriate costs in the ROE has diminished significantly since 1984. Because of these changes, and based on BPA's experience in implementing the ASCM, BPA now proposes that Utilities should be allowed to exchange ROE. As noted previously, this argument goes to BPA's review of ASC filings, not the inclusion of ROE in retail rates. The WUTC notes that (while) including the cost of equity *may* present problems related to abandoned plant, "black-box" settlements or "stale" data, these arguments go to BPA's review of these costs; they are not reasons to exclude entirely what is a legitimate and necessary cost of power resources. (WUTC, ASC0005 at 18.) The WUTC notes there are other means for BPA to ensure that the cost of terminated power plants is not included in a utility's ASC. (*Id. at 19.*) Terminated plants are readily identifiable. (*Id.*) BPA's review of any utility's ASC filings would allow it to make adjustments to ASC components as appropriate on a case-by-case basis. (*Id.*) If the cost of equity is found to reflect terminated plant, BPA can determine the impact on cost of equity and make an appropriate adjustment. (*Id.*)

WPAG notes that meeting the region's load growth with new generating resources increases the likelihood that some of the resources planned to meet this load growth could be terminated prior to commercial operation. (WPAG, ASC0008 at 4.) BPA will need to spend more time and effort, thus increasing the cost of the REP, in order to police this aspect of IOU retail ratemaking. (*Id.*) BPA acknowledges that there will always be the possibility that resources acquired to meet the region's load growth will be terminated prior to commercial operation. BPA necessarily will need to spend time and effort to exclude terminated plant costs from ASC. Nevertheless, BPA is required by law to exclude such costs from ASC and BPA is prepared to devote adequate resources to fulfill its statutory obligations. As described previously, given the current regulatory environment, BPA believes it would be extremely difficult for a Utility to include terminated plant costs in its ASC, even where a Regulatory Body attempted to do so through return on equity. BPA believes it is more appropriate to allow legitimate resource costs in ASC (such as return on equity) than to simply exclude such a cost, even if it requires greater effort to police the inclusion of such costs.

WPAG argues that BPA should use the actual return as shown on the FERC Form 1 filings because the proposed ASCM relies on Form 1 filings for most other data in ASC filings. (WPAG, ASC0008 at 4-5.)

WPAG states that by including the actual return from the Form 1 filing, BPA preference customers that pay for the program will only have to pay for the return actually earn by the IOUs. (*Id*.)

BPA respectfully disagrees. BPA develops wholesale power rates using projected test years and will develop projected ASCs so that they are aligned with BPA rates. BPA uses the allowed rate of return from state commission orders, in part, to develop these projected ASCs. The Base Period ASC filed by IOUs and based on its most recent FERC Form 1 is the starting point of the ASC determination process. BPA must take the costs and loads contained in the Base Year ASC and project them for 3 years in the future. If BPA used the actual returns from the Form 1, BPA would have to project whether or not the actual return, whether above or below the state commission allowed return, would continue. Because the actual IOU rate of return seldom equals the allowed rate of return is no reason to abandon the allowed rate of return. State commission rates of return are prepared on a normalized test year representative of costs and loads expected to occur over the period when rates are in effect. The possibility that a utility's actual ROE will not equal its forecasted ROE should be no more surprising than the fact that a utility's actual power costs or electricity sales do not equal the values contained in a state commission's order.

PPC/NRU argue that because state commissions must balance the conflicting needs of shareholders and ratepayers, they could use the ambiguity in the ROE determination to increase the ROE if they knew that the increase in residential rates as a result of the higher ROE would be offset by higher REP benefits. (PPC/NRU, ASC0006 at 8.) PPC/NRU also argue that an upward bias in ROE determination cannot be extracted easily by BPA from the IOU ratemaking process. (*Id*. at 8.) BPA respectfully disagrees. A higher ROE would also affect rates to other utility customers. Industrial customers of exchanging IOUs are well represented in state commission proceedings and would vigorously oppose any attempt to burden them with higher rates because of the effect of a higher ROE. Information on allowed ROEs is widely available on the Web and BPA will monitor trends in ROEs both in the Pacific Northwest and nationally. Also, as customers of BPA, PPC/NRU are automatically granted party status in BPA's ASC reviews. If they suspect that ROEs are inflated, they can bring their analysis into the ASC review process where it will be considered by BPA and other parties to the process. BPA and its power sales customers also retain the ability to intervene in state utility rate proceedings for purposes of obtaining information relevant to ASC determinations, including allowed ROE.

PPC/NRU argue that because the ROE actually earned by an IOU is a function of numerous other issues such as numerous rate base and expense disallowances, the state commissions have a strong incentive to increase ROE to offset deductions in other areas of the rate order. (PPC/NRU, ASC0006 at 9.) BPA respectfully disagrees. This is similar to PPC/NRU's earlier argument about higher ROEs because the REP benefits will offset the residential rate increase. Again, PPC/NRU ignore the active and aggressive role played by industrial customers and other intervenors in state regulatory proceedings and BPA's ASC review proceedings. BPA has the ability to make independent determinations and decisions on any cost it believes is improperly inflated or is too high. If BPA, or any of the participants in the ASC review process, believes that an ROE is too high for any reason, including offsetting deductions in other cost areas or alleged improper conduct by the state commission, they can raise that as an issue in the ASC review process.

PPC/NRU argues that because many IOU rate orders end in settlements, it is easier for the state commissions to include a higher ROE than they would otherwise allow. (PPC/NRU, ASC0006 at 9.) BPA respectfully disagrees. Again, this argument goes to BPA's review of ASCs, not to inclusion of ROE. BPA will monitor allowed ROEs nationwide and will participate in state regulatory proceedings. If BPA or any participant in the ASC review process finds evidence of manipulated, inflated or otherwise improper ROEs, BPA will adjust the ASC accordingly. BPA has the ability to make independent determinations and decisions on any cost that it believes is improperly inflated or is too high. If BPA, or any of the participants in the ASC review process, believes that an ROE is too high due to settlements or stipulated rate orders, they can raise that as an issue in the ASC review process.

PPC/NRU also argue that allowed ROE can change for reasons not related to conditions in the electric utility, but because of changes in non-regulated subsidiaries or for changes in the gas utility of companies such as Avista and Puget, which provide both retail gas and electric service. (PPC/NRU, ASC0006 at 9.) PPC/NRU argue that increasing waves of mergers and acquisitions occurring in the utility industry, such as the recent Puget merger, could also affect ROE for reasons not related to the electric business. (*Id.*) BPA respectfully disagrees. If a state commission allows a higher ROE than is justified by the evidence presented in the regulatory proceeding, the higher ROEs will affect rates to all customers, which will be vigorously opposed by industrial customers and others. Again, the PPC/NRU argument goes to the level of BPA review. BPA will work diligently to ensure that the allowed returns are not inflated or otherwise manipulated. BPA has the ability to make independent determinations and decisions on any cost that it believes is improperly inflated or is too high. If BPA, or any of the participants in the ASC review process, believes that an ROE is too high due to mergers, acquisitions, non-regulated subsidiaries or any other non-electric business, they can raise that as an issue in the ASC review process.

Finally, PPC/NRU note that in periods of declining cost of capital such as occurred in the mid-1990's, utilities did not file rate changes for many years. (PPC/NRU, ASC0006 at 11.) PPC/NRU argue that by using the allowed ROE from the most recent state commission rate order, BPA's proposed ASCM could overcompensate the IOUs for their cost of capital. (*Id.*) BPA disagrees. This argument goes to the level of BPA's review of ASC filings, not inclusion of return on equity. BPA has the ability to make independent determinations and decisions on any cost that it believes is improperly inflated or is too high by virtue of the vintage of the data. If BPA, or any of the participants in the ASC review process, believes that an ROE is too high due to changes in the capital market, they can raise that as an issue in the ASC review process.

PRC believes that if ROE becomes part of the ASC Methodology, consumer-owned utilities (COUs), such as PRC and its members, should be allowed to include an ROE in the same manner that BPA is currently proposing for IOU's. Unlike shareholder return that drives the determination of IOU return on equity, a cooperative's return on equity is driven by equity planning goals established by its members and lending covenants. These goals establish objectives to support the optimum mix of debt and equity in order to minimize the cooperative's margin requirements and to meet its debt coverage obligations. Additionally, strong equity management practices enable the system to follow the cooperative principal of retiring capital credits to its members as tangible evidence of ownership. This later feature of cooperative equity planning is analogous to an IOU determining dividend levels for its shareholders. (PRC, ASC0001 at 1-2).

A cooperative has real and perceived "risk" just as an IOU has. Similarly, that risk typically translates into a higher cost of equity than debt. BPA's initial proposal was to use just the COU's weighted cost of debt as a proxy for weighted cost of capital. Unless the IOU cost of capital is similarly calculated, COU's will be disadvantaged in the determination of ASC. Therefore, BPA should allow COUs to include a ROE in the determination of the weighted cost of capital in their ASC filings. For a cooperative, this ROE will be based upon the equity planning goals adopted by their Board which is a cooperative's governing body. Similar considerations should be given to other forms of COU's, such as municipals and PUDs, in the determination of ROE to be included in ASC determination. (Id.)

BPA believes a COU should get a return on equity as the PRC argues, but just not based on the approach that PRC states. BPA is giving COUs a return on 'equity' that equals the rate base less the total debt, the capital or 'equity' provided by the customers of the COU, times the weighted cost of debt.

Decision

BPA will allow return on equity in ASC starting from a Utility's most recent Regulatory Body-approved return. BPA may adjust the return on equity for factors such as declining cost of capital not reflected in Regulatory Body approved return on equity or if BPA finds that the Regulatory Body approved return on equity includes the cost of terminated plants. For purposes of determining return on rate base, the Utility will include the weighted cost of capital from its most recent rate order. For Utilities with service territories in more than one state, the Utility will submit a weighted cost of capital based on the most recent Regulatory Body rate orders weighted by rate base in states within the Pacific Northwest region. For COUs, the return component will equal the weighted cost of debt times the rate base included in the ASC filing.

4.8 Taxes

4.8.1 Federal Income Taxes

Issue

Whether Federal income taxes should be included in ASC.

Parties' Positions

The IOUs, WUTC, OPUC and IPUC support inclusion of Federal income taxes in ASC, which should be considered resource costs. (IOU, ASC0004 at 2-3; WUTC, ASC0009 at 20-22; OPUC, ASC0010 at 6; IPUC, ASC0008 at 8-9.)

WPAG argues that Federal income taxes should not be included in ASC because they are a function of the utility's organizational structure and not a cost of resources. (WPAG, ASC0008 at 5-6.) PPC/NRU argues that Federal income taxes are transfer payments from some individuals in society to others and are not resource costs as defined in the Northwest Power Act. (PPC/NRU, ASC0006 at 10-11.)

BPA Position

The proposed ASCM includes Federal income taxes in ASC through "grossing-up" a utility's allowed return on equity at the marginal tax rate so the equity return in the ASC calculation is an after tax return on equity.

Evaluation of Positions

Federal income taxes were included in BPA's 1981 ASCM and, like equity return, were not controversial issues during the initial consultation process. Indeed, inclusion of Federal income taxes and return on equity were not discussed and analyzed as issues in the 1981 ASCM Administrator's ROD. In fact, the only mention in the 1981 ROD was in the ASC Review Procedures, where BPA described the ASC Schedules for utilities' ASC filings. The 1981 ROD showed further evidence of the lack of controversy where it recognized that "[a]greement has been reached by the consulting parties that the costs allowed or established for retail ratemaking purposes should be used in calculating ASC, subject to certain specific requirements." *See* 1981 ASCM ROD at 9. In its order approving the 1981 ASCM, FERC did not address the issue of income taxes. 48 Fed. Reg. 46970-01 (Feb. 3, 1984).

In the 1984 ASCM, income taxes were removed from the ASC calculation. The 1984 ASCM ROD stated that income taxes were not resource costs within the meaning of section 5(c) of the Northwest Power Act. *See* 1984 ASCM ROD at 63. In the 1984 ASCM consultation proceeding, however, there was considerable controversy surrounding the exclusion of income taxes from ASC. The 1984 ASCM was contested at FERC on this issue, among others. In its decision approving the 1984 ASCM, FERC was troubled with BPA's exclusion of income taxes. FERC stated that BPA's rationale to "allow a proxy for equity return while disallowing taxes on such profits is somewhat contradictory." 49 Fed. Reg. 39,293, 39,296 (Oct. 5, 1984). When the Ninth Circuit reviewed the 1984 ASCM, the Court echoed FERC's concern. The Court stated there is "an inconsistency in first disallowing equity return and then further disallowing the taxes on such profits." *PacifiCorp* v. *F.E.R.C.,* 795 F.2d 816 (9th Cir. 1986). The Court nevertheless affirmed BPA's interpretation with the reservation that it did not "sanction any permanent implementation of these exclusions." *Id.*

Under the revised ASC Methodology, BPA is proposing to allow Utilities to exchange the costs of certain taxes through their ASCs. BPA is proposing this change because it is appropriate to have symmetry between the treatment of ROE and taxes. As noted in the section of this ROD discussing return on equity, BPA is proposing to allow the costs associated with equity return as a resource cost in calculation of ASC. If the cost of Federal income taxes at the marginal tax rate is not also included, then an investor-owned utility's cost of resources would be understated. When calculating the revenue requirement for an investor-owned utility, regulatory bodies typically "gross-up" the cost of equity by the marginal Federal income tax rate to arrive at the "after tax" return. In the same manner, because BPA is proposing to include ROE as a resource cost in the ASC Methodology, BPA is also proposing to "gross-up" the equity component by the Federal income tax rate when determining an investor-owned utility's weighted cost of capital in ASC.

The IOUs, WUTC, OPUC and IPUC support inclusion of Federal income taxes in ASC. (IOU, ASC0004 at 2-3; WUTC, ASC0009 at 20-22; OPUC, ASC0010 at 6; IPUC, ASC0008 at 8-9.) The IOUs state that income taxes and revenue related taxes should be considered resource costs. (IOU, ASC0004 at 2-3.) A utility finances the construction of plant using debt and equity. (*Id.*) The return on equity is made available through the utility's net income after taxes. (*Id.*) Therefore, income and revenue related taxes are an integral component of resource cost and excluding these costs from ASC would be inconsistent with the Northwest Power Act. (*Id.*) The tax exempt status of preference agencies does not excuse them from paying the cost of taxes incorporated in the prices of products they purchase. Similarly, the tax exempt status of preference agencies does not require the exclusion of income taxes from ASC. (*Id.*)

The IPUC notes that income taxes are a real, significant, and distinct cost that is incurred by IOUs, and income taxes are widely recognized as one of the costs of conducting business. (IPUC, ASC0008 at 8-9.) The failure to include tax costs would deny the residential and small farm customers of IOUs their benefits under the Act. (*Id.*) In addition to the inclusion of federal income taxes in the ASC, BPA should recognize the impact of federal income taxes on ROE. (*Id.*) State regulatory commissions typically gross-up the IOUs' income deficiency for taxes to arrive at the revenue requirement on an "after tax" basis that reflects the ROE established in a rate case. (*Id.*) This gross-up calculation neutralizes the impact of taxes on rate of return. (*Id.*) Because BPA is proposing to include ROE costs as a component in the ASCM, BPA should recognize the interplay between federal income taxes and ROE. (*Id.*)

The OPUC supports BPA's proposal to include federal income taxes in ASC. (OPUC, ASC0010 at 6.) This proposal recognizes a distinct cost that investor-owned utilities incur. (*Id.*)

The WUTC supports BPA's proposal to include the effect of Federal income taxes in the calculation of ASC. (WUTC, ASC0009 at 20.) Like the cost of equity, federal income taxes are a normal, indeed unavoidable expense an investor-owned utility incurs when acquiring resources and other capital needs. (*Id.*) To exclude income taxes from calculation of ASC would misrepresent the cost of financing and retaining investor capital in the resources necessary to serve utility loads. (*Id.*) As BPA correctly observes, "[i]f the cost of Federal income tax at the marginal tax rate is not also included, then an investor-owned utility's cost of resources would be understated." (*Id.*) An investor-owned utility's income tax obligations are based on all of the utility's net revenues generated from all of its company's sales, including return on distribution and other assets. (*Id.*) Consequently, BPA's proposal to capture the effect of Federal income taxes by adjusting the overall rate-of-return that is applied to the ASC-qualified assets is essential. (*Id.*) Income taxes are an inseparable consequence of the cost of attracting the investor capital necessary for a utility to finance and own the assets it uses to meet the loads of exchange-eligible customers. (*Id.* at 21.) Inclusion of these costs in ASC properly reflects that taxes are an unavoidable cost of doing business and therefore are necessary to include in an accurate ASC. (*Id.*) There is nothing in the Northwest Power Act that requires, or specifically authorizes, BPA to treat that investor-owned utilities like federal income tax tax-exempt entities, who are able to finance resources solely with tax deductible debt, or who can obtain access to government-secured financing resource development through BPA. (*Id.*) Excluding from ASC the income taxes associated with the net revenue necessary to finance the assets required to meet exchange-qualified load is not necessary to allow the BPA Administrator to manage the cost of the resources purchased under the exchange program. (*Id.*) Section 5(c)(5) allows BPA to fulfill its exchange obligations by purchasing a less expensive resource "in lieu" of resources at an exchanging utility's ASC. (*Id.* at 22.)

WPAG argues that Federal income taxes should not be included in the ASC calculation because they are a function of the utility's organizational structure and not a cost of resources. (WPAG, ASC0008 at 5 and 6.) BPA respectfully disagrees. It is true that IOUs pay income taxes because they are profit-making entities, as opposed to consumer-owned utilities. However, IOUs were established well before the Northwest Power Act and therefore before the establishment of the REP. The IOUs thus did not establish themselves in order to become eligible for REP benefits. Given their structure, the IOUs incur income taxes as a cost of acquiring resources and using such resources to meet residential load. As the WUTC correctly points out, "to exclude income taxes from calculation of ASC would misrepresent the cost of financing and retaining investor capital in the resources necessary to serve utility loads." (*Id.* at 2*0*.) Income taxes are a cost of resources in the same way as interest expense. As noted in the section of this ROD discussing return on equity, BPA is proposing to allow the costs associated with equity return as a resource cost in calculation of ASC. If the cost of Federal income taxes at the marginal tax rate is not also included, then an investor-owned utility's cost of resources would be understated. When calculating the revenue requirement for an investor-owned utility, regulatory bodies typically gross up the cost of equity by the marginal Federal income tax rate to arrive at the "after tax" return. In the same manner, because BPA is proposing to include ROE as a resource cost in the ASC Methodology, BPA is also proposing to gross up the equity component by the Federal income tax rate when determining an investor-owned utility's weighted cost of capital in ASC.

WPAG further argues that should BPA allow Federal income taxes in the ASC calculation, it should include the actual taxes paid as included in the FERC Form 1. (WPAG, ASC0008 at 5 and 6.) BPA should not use the marginal Federal tax rate in the ASC calculation because IOUs' effective marginal tax rate is always below the marginal tax rate. (*Id.*) IOUs also note that the FERC Form 1 data reflects actual income and revenue related taxes. (IOU, ASC0004 at 2-3.) Accordingly, they suggest that reliance on such data is simple, verifiable, and avoids issues regarding any difference between actual taxes and allowances for taxes in retail rates. (*Id.*) In contrast, PPC/NRU argues just the opposite. PPC/NRU argues that inclusion of Federal income taxes will greatly complicate the ASC review process because it will invite BPA to become involved in the various methods by which IOUs defer and/or avoid payment of income taxes, and to make judgments about the appropriateness of such decisions. (PPC/NRU, ASC0006 at 10-11.) Also, PPC/NRU argue that inclusion of Federal income taxes will complicate the ASC review process because the IOUs use a variety of funding sources to fund acquisition of new resources because it will be difficult to track the tax burden of a resource or group of resources. *(Id.)* Further, PPC/NRU add that many of the region's IOUs are now part of larger companies as a result of mergers and acquisitions, a trend PPC/NRU argues will continue. This increase in merger activity increases the likelihood that utility holding companies will be able to shift their tax burden to their Pacific Northwest customers, and then to BPA. *(Id.)*

BPA disagrees that it should use the actual taxes paid as reported in the FERC Form 1 instead of grossing up the IOU equity return by the Federal marginal income tax rate for the reasons stated in the paragraph above and for the reasons discussed in the paragraphs below.

First, use of the gross-up factor is how state commissions determine the after-tax revenue requirement in rate orders and is easy to understand and implement. It is simple, straightforward, and over time will approximate the actual taxes paid by the IOUs. The differences between actual taxes paid and taxes used for rate making are due to a variety of factors having to do with the Federal tax code, US law and state regulatory commission orders and policies. In addition, much of the difference between actual Federal income taxes paid and income taxes at the Federal marginal tax rate are due to timing differences resulting from differences between depreciation used for Federal income tax and ratemaking differences that will tend to equalize over the life of the utility assets.

Determination of the "fair just and reasonable" amount of income taxes to include in electric utility revenue requirement has been the subject on what can easily described as one of the most complex, contentious and longest running issue facing state commissions and FERC, stretching back to the 1950s when Congress passed the Internal Revenue Code of 1954, which permitted use of accelerated depreciation for income tax purposes. *See* H.R. Rep. No. 1337, 83rd Cong, 2d Sess 25 (1954). Electric utilities could use straight line depreciation for determining income tax for setting retail rates but used accelerated depreciation actual income tax payments. The difference in income taxes in retail rates and taxes paid started the "Phantom Tax" debate, a series of bitter and contentious regulatory hearings, state laws, ballot measures that continues today in many parts of the US.

The passage of Senate Bill 408 in Oregon (SB 408) is yet another response to the issue of "fair just and reasonable" level of taxes in retail rates. *See* Oregon Citizen's Utility Board, October 14, 2005, CUB Filing MidAmerican Comments Today. SB 408 was passed to ensure that IOUs in Oregon only recover in rates the amount of taxes actually paid to the IRS. Although the concept sounds simple, implementation of this law greatly increase the workload of the OPUC staff. Indeed, the Oregon Administrative Rules concerning implementation of SB 408 cover 11 pages. The difficulty and increased effort and expense associated with implementation of SB 408 lies in the complexity of the U.S. Tax Code and its application to the electric utility industry.

The combination of the fact that utilities are regulated and also very capital intensive has resulted in several unique and complex applications of certain income tax rules. Historically, utilities had been prime beneficiaries of tax legislation that encouraged taxpayers to modernize and expand their plants - primarily through rapid tax depreciation and investment tax credit (ITC) benefits. The unique interaction between income tax accounting, income tax compliance under the Internal Revenue Code (IRC), and the regulatory process created complexities in the income tax area. PriceWaterhouseCooper's Public Utility Manual, March 2007 at 127 and 128. Further, because of the complexity of the IRC and the related Treasury regulations, most of the questions and controversy concerning taxes tend to be focused on income taxes. G. Hahne and G. Aliff, *Public Utility Accounting* 17-4 (Mathew Binder 2005).

The knowledge required to analyze and determine the proper level of electric utility income taxes requires an understanding of several complex issues; interperiod income tax allocation, accelerated depreciation, investment tax credits, inter-company tax allocation, and intra-company tax allocation. *Id*. at 17-5. For example, interperiod tax allocation issues arise when electric utility transactions may affect the determination of net income for financial accounting purposes in one reporting period and the computation of taxable income in a different reporting period. Thus, revenues or gains and expenses or losses may be included in the determination of taxable income either earlier or later than they are included in pre-tax accounting income. Therefore, the amount of income taxes determined to be payable for a period does not necessarily represent the appropriate income tax expense applicable to the transactions recognized for financial accounting purposes in that period. BPA staff does not possess the expertise to prepare an independent analysis of electric utility income tax, nor does it think that it should obtain such expertise for ASCM purposes.

Using the marginal tax rate, WPAG argues, also results in costs included in the ASC that are not being paid by the utility. (WPAG, ASC0008 at 5.) BPA disagrees. First, the ASCs developed by BPA will be for a projected period to coincide with the period that BPA rates will be in effect. For example, BPA currently is developing Base ASCs using data from 2006 FERC Form 1s for IOUs. BPA will then project the data in the Base ASC to 2009 to coincide with the period of time when new BPA rates will be in effect. Thus, it will only be by coincidence that any cost in the projected ASC will be equal to the costs actually incurred by the IOUs. Some actual costs will be higher than the projected costs used in an ASC filing other costs will be lower. This is universally true for almost all costs in any regulatory proceedings that use projected or normalized data. However, the costs will be reasonably representative of the utility's costs.

PPC/NRU argues that Federal income taxes are transfer payments from some individuals in society to others and are not resource costs as defined in the Northwest Power Act. (PPC/NRU, at 10-11.) BPA disagrees with PPC/NRU's argument because nothing in the Northwest Power Act mentions that BPA should or should not include transfer payments in the determination of ASC. In fact, the Northwest Power Act does not even mention the term "transfer payments". Even assuming *arguendo* that income taxes were a transfer payment between different members of society, this does not mean they are not costs of resources as defined in the Northwest Power Act. The Northwest Power Act does not define individual components of resource costs. The Court said "[r]ather, it is assigned to the BPA Administrator in rate making proceedings to devise a 'methodology' for determining costs." *PacifiCorp*, 795 F.2d at 2.

PPC/NRU also argue that inclusion of Federal income taxes will greatly complicate the ASC review process because it will invite BPA to become involved in the various methods by which IOUs defer and/or avoid payment of income taxes, and to make judgments about the appropriateness of such decisions. (PPC/NRU, ASC0006 at 10-11.) BPA disagrees. BPA's proposal is to gross up the IOUs rate of return to reflect the Federal after-tax return for ASC determination.

PPC/NRU also argue that inclusion of Federal income taxes will complicate the ASC review process because the IOUs use a variety of funding sources to fund acquisition of new resources and because it will be difficult to track the tax burden of a resource or group of resources. BPA disagrees because neither the Northwest Power Act nor the proposed ASCM requires tracking the Federal income tax burden of a resource or group of resources. BPA's proposal is to gross up the IOUs rate of return to reflect the Federal after-tax return for ASC determination. BPA's proposal for inclusion of income taxes completely avoids the need for obtaining expertise in Federal income tax law and accounting and getting involved in the tracking of tax burden of a resource or group of resources, assuming that this was required by the Norwest Power Act, which iit is not.

PPC/NRU also adds that many of the region's IOUs are now part of larger companies as a result of mergers and acquisitions, a trend PPC/NRU argues will continue. (*Id*.) This increase in merger activity increases the likelihood that utility holding companies will be able to shift their tax burden to their Pacific Northwest customers, and then to BPA. (*Id.)* Oregon recently signed into law SB 408, which the PPC/NRU argues will "hopefully combat some potential taxes abuses" witnessed in recent years. (*Id.)* BPA should keep in mind, PPC/NRU argue, that SB 408 was passed against strident opposition and could be overturned or weakened in the future, so BPA should not use SB 408 as a backstop against unfair tax shifting by the IOUs. *(Id.)*

BPA disagrees. BPA believes it has eliminated the problem of potential abuse of Federal income taxes with its proposal to use a Federal income tax gross-up factor. The potential abuses mentioned by the PPC/NRU refer to actual Federal income taxes paid by the utility, which BPA will not use in the ASCM. BPA also disagrees with the PPC/NRU's position on this issue because the ASCM does not use actual Federal income tax paid, but uses the Federal marginal tax rate to gross-up the equity return to reflect the after tax return of the IOUs. The tax shifting argument would only apply if the ASCM used the actual Federal income tax paid in the determination of ASC, which it does not. BPA understands the difficulty in determining the actual taxes paid by an electric utility in a given year, especially one that is a wholly-owned subsidiary of a holding company. That is why our proposal to apply a gross-up factor to equity return is superior to use of the actual tax paid, as suggested by WPAG. BPA's proposed approach for income taxes greatly reduces the administrative burden of Federal income tax determination because it uses the Federal marginal tax rate in a simple gross-up factor in an Excel spreadsheet that changes only when the Federal marginal tax rate changes. To use the actual Federal income tax paid would require numerous experts in the area of electric utility income tax policy to determine the amount of actual taxes paid in a particular year. BPA must also keep in mind the ultimate use of the ASCM, which is to develop a rate that will be used to determine the level of payments to residential and small farm customers of exchanging utilities. Due to the complexities of Federal tax law in general, and as it applies to electric utilities in particular, the actual Federal income taxes paid in a particular year can vary significantly over and above the variances caused by increases or decreases in net income or decision of utility management with respect to their approach to Federal income tax policy.

One of the central goals of utility ratemaking is rate stability. Using actual taxes paid could cause unwanted variability in exchange payments, which would lead to variances in retail rates of exchanging utilities, with little apparent benefit. In addition, BPA's proposed approach to inclusion of Federal income taxes results in a stable and consistent treatment for all exchanging utilities and reduces volatility in the retail rates of residential and small farm customers of the exchanging utilities. In addition, the Proposed ASCM uses the exchanging utility's FERC Form 1 to develop ASCs which will be for the year prior to the ASC filing. BPA must then forecast or project these individual ASCs for an additional three years (for a BPA 2-year rate period) so that it can include the projected ASCs into its own rate development process, and an additional four years after that for use in the 7(b)(2) rate test. If BPA used the actual taxes paid by a utility to determine its ASC, it would be forced to determine if the actual taxes paid that year were reasonable and representative or an aberration either up or down, that will not continue in the forecast period. Again, in order to perform such an analysis BPA would have to retain additional expertise in Federal income tax accounting, a cost that BPA believes is not worth the expense or required by the Northwest Power Act. S*ee* 49 Fed. Reg. 39,293, 39,296 (Oct. 5, 1984).

Decision

BPA will include Federal income taxes in ASC. BPA will gross-up the utility's equity component by the Federal income tax rate when determining an investor-owned utility's weighted cost of capital in ASC.

4.8.2 Other Income Taxes

Issue

Whether other state and local taxes, regulatory fees and other levels should be considered a cost of resources for the determination of average system cost?

Parties Positions

The WUTC states that the arguments it raised in support of inclusion of federal income taxes also apply to state and federal revenue related taxes associated with power supply and transmission. (WUTC at 22.) WUTC recommends that BPA include in ASC all taxes incurred as a result of power generation and transmission, such as Federal and state income taxes and the Public Utility Excise Tax (PUET) assessed in Washington. PUET tax expense should be included and allocated according to the PTD allocator. *Id.* The IOUs also argue that income taxes and revenue related taxes should be considered resource costs. (IOU at 2.) Similarly, the OPUC argues that state and local taxes are a cost of resources and a cost of doing business and should be included in ASC. (OPUC at 3.) Further the OPUC argues that Regulatory fees imposed on a utility and related to a resource cost should be included in ASC. (*Id*. at 4.)

BPA Position

The proposed ASCM proposed to include only Federal income tax, property tax on generation and transmission assets and employment taxes as resource costs in the determination of ASC.

Evaluation of Positions

Both BPA's 1981 and 1984 ASC Methodologies did not allow inclusion of other state taxes and fees in ASC.

> In my judgment it is more appropriate to functionalize expenses incurred at the retail level to distribution/other. Therefore, I have adopted a functionalization footnote (see footnote 3) requiring that revenue taxes related to retail sales, and other items unrelated to the power supply level such as bad debt expense, be functionalized to distribution/other.[7]

In the 1984 ASC Methodology BPA did not change the exclusion of revenue related taxes. The functionalization of FERC Account 408.1 provides that:

> With the exception of property taxes and labor related taxes, all taxes will be functionalized to Distribution/Other. Property taxes will be functionalized using the gross plant ratio including general plant. Labor related taxes will be functionalized using labor ratios.[8]

The OPUC argues that state and local taxes are costs of conducting business. (OPUC at 2.) BPA's current proposal to exclude state and local taxes will frustrate the goal of wholesale rate parity because utility ASC will not include a significant component of the cost of conducting business**.** *Id.* The IOUs argue that federal income taxes, state income taxes and state revenue taxes are a cost and a function of providing electricity to the customer. All income or revenue related taxes are a cost the utility pays on the revenues resulting from the rates charged for the production, transmission and distribution of electricity. (IOU at 3.) For example, the Public Utility Tax in Washington generally applies to all revenue generated for utility services provided by investor-owned utilities that operate in the state of Washington. These activities include production, transmission and distribution functions. *Id.* The Montana Electric Energy Producers Tax is a tax on production of electricity. *Id.* Any other generation or transmission related taxes that are incurred by a utility should be functionalized to production and transmission respectively.

BPA disagrees with the parties that taxes other than income taxes are a cost of resources for purposes of ASC Determination. While BPA understands that other taxes such as the PUET, the Oregon Income Tax and the Montana Electric Energy Producers Tax are all costs of doing business, that does not make them costs of resources for ASC determination. Congress chose the Administrator to determine cost of utility resources.[9] The Administrator was chosen to develop a methodology to determine ASC, subject only to the Commission's review. (*FERC Oct. 25, 1984* at 24)

The OPUC argues that the fact that including state and local taxes will "socialize" these costs to all utilities that exchange under the REP is not reason to exclude the costs from utilities' ASC. *Id.* We fail to identify the legal or policy basis for treating state and local taxes differently than other utility costs, especially when excluding such costs would frustrate the objective of wholesale rate parity. (*OPUC* at 3)

BPA did not state that we excluded state and local taxes because they will somehow socialize those costs to other BPA customers. Instead, BPA simply decided that those taxes are not resource costs

[7] Administrator's ROD, 1981 ASCM at 13.
[8] Administrator's ROD, 1984 ASCM at 85.
[9] 49 Fed. Reg. 39,293, 39,296 (Oct. 5, 1984).

under the ASC Methodology. BPA also disagrees that exclusion of state and other revenue related taxes will frustrate the objective of wholesale rate parity. As FERC stated in its approval of the 1984 ASCM:

> it is not clear what "wholesale rate parity" means. BPA states that it "simply means that the wholesale rate used for BPA's paper sales under the exchange program is to be the same rate used for actual sales to BPA preference customers." IOUs contend that "wholesale rate parity" means that the ASC "must contain all other wholesale power cost items" except those excluded under sections 5(c)(7) (A), (B) and (C). This approach would require BPA to recognize in the ASC all but the prohibited cost-of-service items. Unfortunately, these conflicting arguments do not advance the inquiry very far, considering how various regulatory commissions apply different ratemaking approaches to ascertain the cost of service.[10]

FERC further notes later in the same Order:

> The Commission finds that BPA reasonably construes the NPA not to require payment of every cost that an IOU incurs. The Commission finds tenable BPA's argument that Congress did not intend to place IOU customers and the customers of publicly-owned utilities on precisely the same ground by eliminating every financial difference between the IOUs and the publicly-owned utilities.[11]

The OPUC states that the specter that governments may manipulate tax obligations in order to "game" the Residential Exchange Program is not sufficient reason to exclude the costs from ASCM. *Id.*

Under the 1981 methodology, BPA has dealt with a revenue related state tax seemingly tailor-made for regionalization through the residential exchange. Idaho Power Co. attempted to include in ASC the so-called Idaho "KWH tax." Section 63-2701 of the Idaho Code. Exceptions and exemptions in the Idaho KWH tax remove the requirement of payment from many, if not all, of the affected electric utility's commercial and manufacturing customers. That is, the tax almost exclusively applies to the retail customers whose rates are subsidized under the residential exchange.

As in both 1981 and 1984 it is BPA's position that the ability of state and local taxing authorities to shift the incidence of a tax obligation to rate payers outside the taxing jurisdiction is sufficient reason to exclude these costs from the ASCM. Therefore it is BPA's conclusion that these state and local those taxes are not exchangeable under the ASC methodology.

The OPUC states that regulatory fees imposed on a utility and related to resource costs should be included in the utility's ASC. Under Oregon statute, public utilities must pay to the OPUC an annual fee to defray the OPUC's costs in performing its statutory obligations. The fee is a significant cost to utilities operating in Oregon. Much of the OPUC's regulatory activities include annual reviews of utility generation power costs, review and monitoring of utility integrated resource planning, review of Energy

[10] *Id.*
[11] *Id.*

Trust activities, carbon regulation and transmission coordination focusing on wind integration, estimating the investor return required for investing in the utility, review of utility financing applications for securing funds to pay for new generation resources, and actively participating in BPA forums, dockets and residential exchange issues. (OPUC, ASC0010 at 4). In addition, the IOUs argued for inclusion of several other miscellaneous taxes and fees. (IOU at 2 - 6.)

BPA does not believe that regulatory fees and other miscellaneous taxes and fees are resource costs for purposes of ASC determination. As noted in the 1981 ASM ROD

> In my judgment it is more appropriate to functionalize expenses incurred at the retail level to distribution/other. Therefore, I have adopted a functionalization footnote (see footnote 3) requiring that revenue taxes related to retail sales, and other items unrelated to the power supply level such as bad debt expense, be functionalized to distribution/other.[12]

As both BPA and FERC noted, it is not necessary to require payment of every cost an IOU incurs to have a fair and equitable REP program.[13]

Decision

BPA will exclude all state and local income and revenue related taxes, excise taxes and miscellaneous fees from the determination of Average System Cost.

4.9 Transmission

Issue

Whether BPA should include all transmission costs in ASC.

Parties' Comments

Parties submitted comments both in favor and in opposition to BPA's proposal to include all transmission costs in the new ASC Methodology. The IOUs, OPUC and IPUC were generally in favor of BPA's proposal to include all transmission costs. (IOU, ASC0004 at 8-10; OPUC, ASC0010 at 6; IPUC, ASC0003 at 6.) They note that including all transmission costs avoids penalizing a utility's past resource siting decisions. (*Id.*) They also note that excluding transmission would have detrimental effects on a utility's future resource decisions by favoring more expensive resources that were closer to loads. (*Id.*) The IPUC and IOUs both explain that this result would economically harm utilities that must acquire more and more renewable resources because these projects typically must be sited near the resource rather than the load center. (IOUs, ASC0004 at 4; IPUC, ASC0003 at 7.)

[12] Administrator's ROD, 1981 ASCM at 14.
[13] *Id.*

Snohomish and the WUTC suggest that ASCs should contain the "symmetrical" transmission costs that BPA includes in its PF Exchange rate. (Snohomish, ASC0009 at 3; WUTC, ASC0005 at 10-11.) Snohomish advocates comparable costs in the ASCs and PF Exchange rate. (Snohomish, ASC0009 at 3.) The WUTC generally supports including transmission costs to the extent they are also included in BPA's PF Preference and PF Exchange rates. (WUTC, ASC0005 at 10-11.)

PPC/NRU and WPAG do not support BPA's proposal to include all transmission costs in ASC. PPC/NRU state that BPA should not include any transmission costs in ASC. (PPC/NRU, ASC0006 at 4-6.) WPAG argues that BPA should exclude transmission costs that are not in the PF Exchange rate to avoid a mismatch with the PF Exchange rate. (WPAG, ASC0008 at 4.) WPAG also argues that BPA should only allow transmission costs that serve the sole purpose of "generation integration," and exclude any transmission costs associated with any other functions. (*Id.*)

BPA's Position

Transmission costs are a cost to a utility of delivering power to load and should be included in the calculation of a utility's ASC. Increasingly, utilities rely on transmission to find the least cost resource available to serve load. This includes bringing power to load from distant, lower cost generation, particularly renewable resources such as wind where moving fuel to local generation is not an option. In addition, dramatic changes in the electricity industry have taken place since BPA originally developed the 1984 ASC Methodology, such as increased reliance on independent power producers to develop generation to sell at market ("merchant plant") or under long-term power purchase agreements; strengthening of wholesale power markets; increased reliance on planning and operating the region's transmission system under a "one utility" vision through ColumbiaGrid (an independent regional transmission entity); the creation of an Independent System Operator in California; and a more constrained transmission system. These changes support including transmission as a cost of ASC. BPA should, therefore, include transmission as a component of ASC.

Evaluation of Positions

Before addressing the parties' comments, a brief overview of the historical treatment of transmission costs in BPA's various ASC Methodologies is warranted. Transmission costs have always been a component of ASC in the ASC Methodologies previously developed by BPA. In the 1981 ASC Methodology, an exchanging utility's *entire* transmission investment and expense were included in ASC. To reiterate, all transmission costs were included in ASC. This approach was adopted pursuant to a negotiated settlement and agreed to by all parties. *See* Administrator's 1981 ASC Methodology Decision, at 1-2. FERC granted final approval to the 1981 ASC Methodology on October 17, 1983. *See Sales of Electric Power to Bonneville Power Admin., Methodology and Filing Requirements*, 48 Fed. Reg. 46,970 (Oct. 17, 1983).

Three years later, in the 1984 ASC Methodology, BPA again allowed transmission costs in ASC. Of particular concern during the consultation process was the belief that exchanging utilities may build unnecessary transmission facilities or facilities used to exclusively serve out-of-region sales. *See* 1984 Average System Cost Methodology Proposal, Administrator's Record of Decision at 42-43, (June 4,

1984) ("1984 ASCM ROD"). BPA evaluated these issues in its 1984 ASCM ROD and determined that, as a legal matter, BPA was not either required or prohibited from including transmission costs in ASC. *Id.* at 42. Consequently, the question of whether all transmission costs would be in or out of ASC was a matter of policy. *Id.*

As a matter of policy, for the 1984 ASC Methodology, BPA decided to include transmission costs. (*Id.*) However, BPA agreed that some limitations should be placed on an exchanging utility's ability to include the cost of transmission that was not built to serve regional loads. The key question became defining which facilities' costs would be allowed in ASC. Numerous proposals were presented, but the parties could not reach consensus. Ultimately, BPA decided to adopt what amounted to a compromise. Specifically, BPA stated that it would allow additional transmission costs in ASC, but limit such costs according to the following criteria:

> For transmission plant commencing service after July 1, 1984, transmission plant costs which can be exchanged are limited to transmission facilities that are directly required to integrate resources to the transmission system grid. Specifically, transmission costs which can be exchanged are limited to the lesser of the costs of transmission facilities required to transmit power from the generating resource to the exchanging utility's system or the sum of the costs of the transmission facilities required to integrate the generating resource to the BPA system and the wheeling costs necessary to wheel the power over the BPA system to the exchanging utility's system. If the utility chooses to construct facilities that are more costly than the facilities required to interconnect to the BPA system, the total costs of that facility to be exchanged shall be no greater than the facility costs that would have been incurred to interconnect with the BPA system.

Id. at 42-43. Simply put, costs of existing transmission were included in ASC. In addition, for transmission facilities constructed *after* July 1, 1984, BPA would only allow the cost to be included in ASC if it met two criteria. First, the facilities had to be used to "integrate resources to the transmission system grid. . ." *Id.* That is, the transmission facilities must be for delivering generation from a resource to the utility's system. Second, the cost of those facilities had to be less expensive than the cost of constructing facilities to connect the same resource to BPA's transmission system plus any transmission charges BPA would charge to transmit the resource to the utility. If the transmission facilities failed to meet either criterion, its costs would be excluded from ASC.

The compromise BPA adopted in 1984 ASCM was intended to address the two divergent views that were expressed during the consultation process. On one hand, BPA's proposal allowed exchanging utilities to retain in their ASCs the costs of *all* transmission that was built prior to July 1, 1984, regardless of its use or function. This result allowed BPA to avoid the difficult "definitional problem" that prohibited the parties from reaching a consensus on which transmission facility costs qualified for inclusion in ASC. On the other hand, the limitations described in the Record of Decision allowed BPA to assuage the concerns that exchanging utilities would increase their ASCs with the construction of unnecessary or extra-regional transmission facilities.

On review at FERC, the Commission acknowledged that BPA's compromise approach was reasonable. *See Methodology for Sales of Electric Power to Bonneville Power Administration*, 49 Fed. Reg. 39,293, 39,299 (Oct. 5, 1984). Although FERC concurred with BPA's legal analysis that nothing in the Northwest Power Act required including transmission costs in ASC, the Commission was "confident that BPA has struck an equitable balance on this issue and has not contravened the NPA by including transmission costs." *Id*.

Twenty-four years have passed since BPA originally adopted this compromise in the 1984 ASC Methodology. In these twenty-four years, the energy industry has seen tremendous changes in both the wholesale power and transmission markets. Regional power markets have matured significantly since 1984 to the point that utilities now regularly buy and sell power in the wholesale power markets. Utilities can now purchase power from a larger pool of participants at market clearing prices through entities like the Independent System Operator in California, or at prices tied to an index such as the Mid-C or COB Dow Jones Electricity Price Index. These transactions exceed by several times the number of bilateral agreements that were negotiated in wholesale markets in 1984. There is now increased reliance on independent power producers to develop generation to sell at market ("merchant plant") or under long-term power purchase agreements to serve load. There is increased reliance on planning and operating the region's transmission system under a "one utility" vision through ColumbiaGrid, a regional transmission entity whose purpose is to facilitate "one utility" planning and operation of the region's transmission grid through a single transmission entity managed by an independent board. Further, the increased reliance on transmission to import generation into utility service territories to serve load at least cost, and a lack of corresponding transmission investment, has resulted in a more constrained transmission system than existed in 1984.

In the transmission markets, major changes have occurred with the unbundling of transmission and power rates through the FERC's unbundling requirement in Order No. 888. *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, FERC Stats. & Regs. ¶ 31,036, 61 Fed.Reg. 21,540 (1996) ("Order No. 888"). In 1999, BPA administratively separated its power and transmission functions to voluntarily comply with the Commission's order for investor-owned utilities to separate generation and transmission. Consequently, BPA now develops separate rates for power and transmission. Further changes have occurred with the creation of regional transmission organizations (RTOs) as well as other forms of regional transmission coordination.

Electric utilities have a variety of robust ways to acquire generation to serve retail load, most of which entail incurring transmission costs. For example, utilities can: (1) rely on wholesale power markets; (2) build centralized generation units close to the fuel source; (3) build generation close to the load center and transport the fuel source (*e.g.* coal by rail); (4) import power from outside the region; and (5) purchase power under long-term power purchase agreements with independent power producers. In addition, many large power plants are owned by more than one utility.

In light of all of these changes, BPA announced in its February 7, 2008, Federal Register Notice that it was proposing once again to include all transmission costs in ASC. 73 Fed. Reg. 7270, 7275 (Feb. 7, 2008). BPA noted that the diversity in the methods of acquiring electric generating capacity to serve retail load means that excluding transmission costs from the ASC calculation would have adverse effects on Utilities. *Id.* In particular, exclusion of the transmission component of electricity production and delivery would introduce an inequity between Utilities that develop resources close to their service territory and those that develop geographically distant resources. *Id.* at 7276. BPA, therefore, proposed to return to its original position of including all transmission costs in ASC.

The IOUs and state commissions generally agree with BPA's decision to move away from the 1984 ASC compromise. (IOUs, ASC0004, at 8-10; WUTC, ASC0005 at 11.) The IOUs note the 1984 ASC Methodology created certain "vintages" of transmission and "subfunctionaliz[ed]" transmission into "integration" and "other" categories, which complicated the calculation of the ASCs. (*Id*. at 8.) The IOUs also contend that nothing has changed since the 1984 ASC Methodology that would require BPA to exclude transmission from ASC. (*Id*. at 9.) The WUTC also correctly notes that BPA included transmission costs in the 1981 ASC Methodology, and nothing in the Northwest Power Act precludes returning those costs to ASC. (WUTC, ASC0005 at 11.)

The IOUs' and state commissions' main contention for including transmission costs in ASC is that it avoids penalizing the resource siting decisions of the exchanging utilities. (IPUC, ASC0003 at 6; OPUC, ASC0010 at 6; IOU, ASC0004, at 9-10.) They note that many utilities decided to site their resources away from load centers because the projected costs of transporting fuel to the resources (such as coal) would exceed the cost of transmission facilities to bring the generated electricity to the load. (*Id.*) For example, the IOUs explain that a utility may locate a generation plant closer to load, thereby eliminating transmission plant investment, and invest in facilities to transport the fuel ("coal by truck"). (IOU, ASC0004 at 9.) Alternatively, a utility might determine to locate a generating plant near a coal mine and invest in transmission facilities to deliver the power generated by the plant to load ("coal by wire"). (*Id*. at 9.) The IOUs contend that if BPA removes transmission from ASC it "imposes a penalty" on those utilities that made an economic decision to site their generation at greater distances from their load. (*Id*. at 9-10.) The IPUC similarly provides examples of these scenarios, and notes that all of the coal fired generation used in Idaho is transported to Idaho load centers from distant locations. (IPUC, ASC0003 at 7-8.)

The OPUC and WUTC also make the point that not including transmission in ASC would have detrimental effects on a utility's future resource decisions. (WUTC, ASC0005 at 10-11; OPUC, ASC0010 at 6.) They note that expensive resources located closer to load centers would be favored over cheaper resources located further away, resulting in economic inefficiency. (*Id.*) The OPUC states these types of decisions should not be influenced by the ASC Methodology. (OPUC, ASC0010 at 6.) The OPUC concludes that BPA's proposal to include transmission avoids these problems, and promotes economic efficiency. (*Id.)*

The IOUs and IPUC both assert that excluding transmission costs would particularly harm utilities that need to acquire more renewable resources. (IPUC, ASC0003 at 7; IOU, ASC0004 at 10.) Both parties explain that renewable resources, such as wind, geothermal, and solar, typically need to be located where the resources are, without regard to where the load is located. (*Id.*) They claim that transmitting the output of these renewable projects to loads consequently becomes a significant component of the costs of these resources, and therefore, should be included in the ASC determination. (*Id.*)

BPA concurs that the reasons explained in the comments of the IOUs and state commissions are important considerations that warrant returning transmission costs to ASC. The IOUs' concern that retaining the "vintaging" of transmission as required under the 1984 ASC Methodology would complicate the ASC determination process is particularly apropos. One key objective of the new ASC Methodology is to streamline and simplify the review process, and to make the ASC determinations more manageable. Moving away from the compromise BPA adopted in the 1984 ASC Methodology alleviates a significant administrative burden on BPA and the parties. Further, the "coal-by-wire" issue raised in the IOUs' and state commissions' comments echoes one of the reasons BPA gave in its February 7, 2008, Federal Register Notice for allowing all transmission costs back into ASC. *See* 73 Fed. Reg. 7270, 7276 (Feb. 7, 2008).

Several other parties commented that there should be "symmetry" between the transmission costs included in BPA's PF Exchange rate and transmission costs included in ASC. Snohomish comments that the ASC and PF Exchange rate should contain comparable costs. (Snohomish, ASC0009 at 3.) If the ASC contains transmission, then the transmission costs should be included in the PF Exchange rate. (*Id.)* The WUTC supports BPA's proposal to include transmission in ASC, with the caveat that these costs should be included in the ASC to the "degree" they are included in the PF Preference and PF Exchange rates. (WUTC, ASC0005 at 10.) The WUTC explains that the cost of resources a utility uses to serve loads is both generation and the cost of delivering that generation to load centers. (*Id*.) According to the WUTC, including one component (resource costs) but not the other (transmission costs) would likely distort utility resource decisions. (*Id*.) The WUTC concludes that consistency requires that both BPA's costs and the utility's ASCs include transmission in the same manner and degrees. The WUTC supports including transmission costs in ASC in order to ensure this symmetry. (WUTC, ASC0005 at 11.)

WPAG comments that BPA's proposal to include all transmission costs in ASC would create a "mismatch" between the costs included in ASC and the costs included in the PF Exchange rate. (WPAG, ASC0008 at 3.) WPAG argues that since BPA functionally separated into power and transmission services, transmission costs have not been included in the PF Exchange rate. According to WPAG, comparing an ASC that contains transmission costs with a PF Exchange rate that does not is an "apples to oranges" comparison that results in unjustifiable increases in REP costs. (*Id*.) WPAG concludes that the ASC calculation under the ASCM must "track" with the costs that are included in the PF Exchange rate. (*Id.* at 4.) BPA, therefore, must either eliminate transmission and related expenses from ASC or gross-up the PF Exchange rate by including transmission incurred by preference customers. (*Id*.)

BPA agrees there needs to be consistency between the transmission costs included in the PF Exchange rate and the transmission costs included in ASC. The purpose of comparing a utility's ASC with the PF Exchange rate is to calculate the REP benefits to an exchanging utility's residential consumers. This comparison can only work if the two rates being compared are constructed of the same component parts. Without this symmetry, the result would be an "apples to oranges" comparison that would inappropriately increase or decrease REP benefits to the exchanging utilities. (*See* WPAG, ASC0008 at 3.) BPA, therefore, acknowledges that there must be "symmetry" between the PF Exchange rate and ASC.

BPA, however, cannot commit through this process to develop the PF Exchange rate in any particular manner in future rate proceedings. The rate design methodology that BPA uses to create the PF Exchange rate is a rate case issue, which must be decided in the context of a section 7(i) rate proceeding. *See* 16 U.S.C. § 839e(i). Decisions made in rate proceedings must be based on the record and cannot be predetermined through other processes. *Id.* at § 839e(i)(5). Although BPA cannot commit to developing the PF Exchange rate in any way, it can commit to initially propose in its rate proceedings to include transmission costs in the PF Exchange rate so that it will be "symmetrical" to the ASCs developed under the ASC Methodology. In any event, however, BPA will not implement the REP in a manner that does not reflect the foregoing symmetry regarding transmissions costs.

PPC/NRU do not support BPA's proposal to include transmission costs in ASC. PPC/NRU finds it "noteworthy" that in 1984 the IOUs argued that because BPA's rates included both transmission costs and power costs, the ASC Methodology should also allow transmission costs in determining ASCs in deference to "wholesale rate parity." (PPC/NRU, ASC0006 at 4-5.) Now, however, even without the inclusion of transmission costs in BPA's rates, PPC/NRU assert BPA is proposing to include transmission costs in ASC determinations. (*Id*. at 5.)

Though not exactly clear, PPC/NRU's comment seems to be implying that BPA previously rejected the IOUs' argument that ASC should include all transmission costs when developing the 1984 ASC Methodology, even though BPA's own rates at the time included both transmission and generation costs. (*Id.* at 5.) If that is what PPC/NRU is attempting to assert, then it is operating under a fundamental misunderstanding of the 1984 ASC Methodology. The 1984 ASC Methodology includes *most* of the exchanging utilities' transmission costs. As explained above, when the IOUs raised concerns about removing transmission costs from ASC, BPA responded by allowing the costs of *all* transmission that was in operation prior to July 1, 1984, into the ASC determination. This concession meant that the costs of all of the existing transmission facilities of the exchanging utilities were automatically allowed into ASC. In addition, the 1984 ASC Methodology allowed all *new* transmission into ASC provided that it could meet the two criteria described in the 1984 ASC Methodology ROD. *See* 1984 ASC ROD at 42-43. Furthermore, BPA adopted these provisions even though it found that it had no legal requirement to include transmission costs in ASC. *Id.* at 42. These actions indicate that BPA was concerned about the IOUs' issue of "wholesale rate parity" as it related to transmission costs under the 1984 ASC Methodology. PPC/NRU's assertion that BPA somehow rejected these concerns of the IOUs when developing the 1984 ASC Methodology is unfounded.

PPC/NRU also take issue with the observations BPA made in the Federal Register Notice that described the background for BPA's proposal to include all transmission in the proposed ASC Methodology. (PPC/NRU, ASC0006 at 5-6.) As noted above, BPA explained in the Federal Register Notice that changes in the electricity industry were important developments that support including transmission costs in ASC. *See* 73 Fed. Reg. 7270, 7276 (Feb. 7, 2008). In its comments, PPC/NRU presents several arguments alleging that the changes noted in BPA's FRN do not warrant allowing transmission costs back into ASC. (PPC/NRU, ASC0006 at 5-6.)

First, PPC/NRU argue that wholesale power markets existed in 1980, which was before the 1984 ASC Methodology, so their presence does not justify changes now. (PPC/NRU, ASC0006 at 5.) First, due to the *enormous* changes in the wholesale power market between 1980 and 2008, one cannot reasonably equate the existence of the former to the latter. Also, PPC/NRU appear to misunderstand the relevance of the changes that the wholesale power market has on the calculation of a utility's ASC. BPA did not say in its Federal Register Notice that the mere "existence" of wholesale power markets made changes to the ASC Methodology necessary. Rather, BPA stated that with the "change[s] in industry structure, electric utilities have a variety of ways to acquire generation to serve their retail load." *See* 73 Fed. Reg. 7270, 7276 (Feb. 7, 2008). This statement simply recognized the obvious fact that utilities have far more resources to choose from today then they did twenty-four years ago. This statement also recognized the fact that utilities have far more resources, suppliers, and business strategies to choose from today to serve load than they did twenty-four years ago—because of increased reliance on transmission.

Although this diversity of choice provides utilities with more options to find least-cost supply solutions, nearly all of these choices entail absorbing significant transportation costs as utilities purchase generation from a larger pool of potential sellers or develop their own generation. Indeed, purchased power, which nearly always entails paying transmission costs, is playing a much more significant role in utilities' resource mix than it did in 1984. As an administrative matter, it would be virtually impossible for BPA to remove the transmission component from these transactions without access to the individual contracts. Such information is not readily available, not consistent from contract to contract, and is difficult to assess once obtained. All of these factors militate in favor of including transmission in ASC.

PPC/NRU also states that the Northwest does not have a Regional Transmission Organization (RTO), so the fact that RTOs exist cannot be a reason to justify a change in BPA's rate-setting processes in the Northwest. (PPC/NRU, ASC0006 at 5.) BPA concurs that the Pacific Northwest does not have an operational RTO at this time. However, BPA and other transmission providers are taking steps toward planning and operating the region's transmission system under a "one utility" vision (that is, as though owned and operated by a single transmission owner). BPA and a number of regional utilities, including publicly owned utilities, are active members in ColumbiaGrid, a non-profit membership corporation formed in 2006 to improve the operational efficiency, reliability, and planned expansion of the Pacific Northwest transmission grid. The corporation itself does not own transmission, but its members and the parties to its agreements own and operate an extensive network of transmission facilities. ColumbiaGrid is developing a number of tools to achieve its objective, including transmission planning, a common ATC methodology, a common OASIS, and improved reliability such as redispatch.

In addition, FERC has adopted policies to promote regional transmission cooperation, improve reliability of the grid as a whole instead of utility-by-utility, to encourage transmission development through enhanced rates of return and other rate incentives, to facilitate siting of transmission through establishing federal transmission corridors, to assure wholesale power markets are relatively free of manipulation, and generally to assure broader choice for utilities to serve load. More than ever, the power industry is in many ways a transmission-centric business.

These and other types of measures demonstrate that regional utilities are operating in a new regulatory paradigm that stresses coordination and cooperation in transmission planning. This environment is remarkably different than what existed in 1984 when BPA developed the previous ASC Methodology.

As noted above, participants in that process were concerned that exchanging utilities would construct duplicative or redundant transmission facilities and place the costs of these facilities on BPA's ratepayers. *See* 1984 ASCM ROD at 41-43. Due to the above-noted regulatory changes and regional cooperation, these concerns generally do not exist today. Therefore, allowing all transmission costs back into ASC makes sense.

PPC/NRU also argues that the functional separation of generation and transmission as a result of FERC Order No. 888 argues against inclusion of transmission costs in ASC because separate functions have led to separate rates. (PPC/NRU, ASC0006 at 5.) PPC/NRU's comment misses the point. BPA's reference to Order No. 888 in its Federal Register Notice was a general reference to another significant change in the regulatory environment that supports allowing transmission costs back into ASC. Prior to Order 888, vertically integrated utilities had the ability to discriminate against other users of their transmission system. Power producers and other utilities wishing to use a third-party transmission system could not be assured they would be allowed to gain access to the transmission provider's system on reasonable terms and conditions. In this type of regulatory environment, alternatives such as building duplicative or redundant transmission lines were a real and possible outcome. Now, with the imposition of Order 888 and its progeny, open access to transmission is almost universal. The problem of a utility building an unnecessary duplicative transmission line, which was a primary concern in the 1984 ASC Methodology, is far less troubling today.

Furthermore, BPA fails to see how separating rates into two rate schedules supports a position that transmission should be excluded from ASC. Simply because a utility separates its rates into one, two, or five rate schedules does not mean that its ASC has dramatically changed. The key question is the utility's average system cost of resources. Historically, BPA has always included transmission costs as a component of resource costs in ASC. Rate unbundling has not fundamentally changed this aspect of ASC. The only issue created by rate unbundling is ensuring that the ASCs and BPA's PF Exchange rate are symmetrical. As described earlier, BPA intends to address these issues in its rate processes.

PPC/NRU asserts that the changes mentioned in BPA's Federal Register Notice are "irrelevant" to revising the ASC Methodology because all of the options for integration of new resources were also available in 1984. (PPC/NRU, ASC0006 at 6.) PPC/NRU explains that some utilities rely on "coal-by-wire" while others on "coal-by-rail," and that these options still exist and are not fuel dependent. (*Id.)* BPA does not understand PPC/NRU's argument. It appears PPC/NRU are stating that the issue of resource integration existed back in 1984. BPA fails to see how this makes the factors BPA identified "irrelevant." BPA agrees that the location of resources was a consideration in 1984 and is still a consideration today. In fact, in the 1984 ASC consultation proceeding, the IOUs raised this same concern. The IOUs argued that excluding all transmission would result in inequities between utilities that have resources closer to load centers and utilities that have generation located closer to its fuel source. *See* 1984 ASCM ROD at 37. Ultimately, BPA was persuaded to include most transmission costs in ASC even though BPA found that it was not legally required to do so. *Id.* at 42-43.

In this proceeding, the IOUs and several of the state commission have once again raised the issue of resource siting and the inequities of excluding transmission costs. As noted earlier, BPA finds these arguments persuasive. (*See* IPUC, ASC0003 at 6; OPUC, ASC0010 at 6; IOUs, ASC0004, at 9-10.) An inequity would be created if BPA were to exclude transmission costs. As a policy matter, it would not be reasonable to exclude a portion of a utility's resource costs where that utility made a reasonable economic decision to site its generation closer to its source of fuel, particularly where Northwest utilities must, for policy and cost reasons, increasingly rely on distant renewable resources that must be located where the resources are located.

PPC/NRU claim that the options of "coal-by-wire" and "coal-by-rail" are not "fuel dependent." (PPC/NRU, ASC0006 at 6.) BPA interprets this comment to mean that PPC/NRU do not think transportation costs are a major consideration in the siting of resources. That statement may or may not be true with coal and other fossil fuels, but it is definitely not the case with most renewable resources. Several Northwest states have adopted aggressive renewable resource portfolio standards. For these resources, such as wind, transmission investments are essentially mandated because "wind-by-rail" is not possible. Similarly, geothermal generation can only be sited at or near the location of the resource. The cost of transmitting energy from these projects to the exchanging utility's load is a significant component of the costs of acquiring these types of resources. (*See* IOU, ASC0004 at 10.) If BPA were to adopt PPC/NRU's proposal and exclude all transmission costs from ASC, it would have an adverse effect on the utilities that are required by state law to acquire renewable energy, which in many cases must be located hundreds if not thousands of miles from load centers.

Finally, PPC/NRU argues that including transmission in ASC could create a number of biases. For example, PPC/NRU assert that BPA's proposal would create a bias toward developing more distant resources because the COUs would be picking up part of the cost of transmission through the REP. (PPC/NRU, ASC0006 at 6.) PPC/NRU believes that this result will lead to greater reliance on distant resources that will, in turn, impact the reliability of the Northwest transmission system. (*Id.*) Second, PPC/NRU believe that including transmission in ASC determinations will create a bias against investment in conservation, because it will make distant generation appear to be less expensive than it really is. (*Id.*)

BPA disagrees that biases in resource decision would result as a consequence of including transmission costs in ASC. Including transmission costs in ASC does not change the underlying economic question of the most efficient means of delivering power to load. If constructing the generator closer to load is cheaper than transmitting it over hundreds of miles of transmission lines, then the utility would likely adopt this option, all other factors being equal. If it is cheaper to wheel power to load, then the utility would likely adopt this option.

Either way, the exchanging utility will have to satisfy its regulators that its choice makes economic sense. BPA's proposal does not create a bias for one option over another because it takes a neutral position on the transportation aspects of this decision. Indeed, BPA's proposal tends to neutralize the inequitable biases that would occur if transmission costs were excluded. If transmission costs were not allowed in ASC, utilities would potentially be biased in favor of more expensive resources closer to load centers.

Following PPC/NRU's logic, excluding transmission costs would tend to bias exchanging utilities against renewable resources, which tend to be located some distance from load. BPA's proposal, consequently, is the better choice because it avoids these biases and adopts a neutral position on the transportation aspects of resource decisions. If, as a tertiary consequence of BPA's proposal, utility investment more in transmission, BPA sees that as a good thing for the region because new transmission investment tends to relieve congestion and increase reliability.

PPC/NRU concludes that BPA should not allow transmission costs as a resource cost in determining ASCs at all. (PPC/NRU, ASC0006 at 6.) As BPA previously explained in the 1984 ASCM ROD, "[w]hen reviewing the ASC methodology the Administrator is provided considerable discretion by section 5(c)(7). The inclusion of transmission costs is permitted by the Act but not required. The question for the BPA administrator to decide then becomes one of policy." 1984 ASCM ROD at 41. Thus, nothing in the Northwest Power Act prohibits BPA from including transmission costs in the determination of an ASC. BPA believes the policy reasons articulated above and in the Federal Register Notice warrant returning to its original position of allowing all transmission costs in ASC.

Moreover, PPC/NRU's own comment does not support its conclusion that all transmission be excluded from ASC. PPC/NRU note throughout their comments that nothing significant has "changed" since 1984 that would warrant a change in the ASC Methodology as BPA has proposed. Assuming *arguendo* that PPC/NRU was correct, it then follows that BPA should remain with its previous treatment of transmission under the 1984 ASC Methodology. As explained earlier, that treatment allowed *all* transmission costs in ASC that existed prior to 1984, and *all* subsequent transmission that met the criteria identified in the 1984 ASCM ROD. PPC/NRU's comments do not demonstrate that BPA should move even further beyond this historical treatment and exclude *all* transmission going forward.

WPAG argues that if BPA decides to stay with its proposal, it must limit the types of transmission costs that can be included in ASC. (WPAG, ASC0008 at 4.) Specifically, WPAG asserts that BPA must limit the transmission costs to facilities that serve solely the "generation integration" function. (*Id.*) WPAG explains that transmission is used for a variety of purposes and not just generation integration. (*Id.* at 3.) BPA's proposed ASC Methodology makes no distinction between transmission used to serve generation integration function exclusively and transmission used for other purposes. (*Id.*) As such, WPAG contends that the proposed ASCM permits the inclusion of transmission costs that are not resource related costs. (*Id.*)

WPAG's comment essentially requests BPA to retain the 1984 ASCM ROD compromise on transmission. BPA declines to do so. The 1984 compromise was adopted in a regulatory and industry climate that viewed redundant and duplicative transmission facilities as a significant threat to the stability of ASC. That threat, as noted earlier, has abated significantly with the changes in the regulatory environment and energy industry as a whole. Moreover, the time and cost of building new transmission has increased significantly since 1984. It is highly unlikely that a utility would commit its resources to obtain all of the environmental, regulatory, and other approvals necessary to build a duplicative or redundant line. All of these changes militate against retaining the 1984 ASCM compromise on transmission costs.

In addition, BPA notes that the present transmission network operates in many respects already as "generation integration." The transmission costs that are included in a utility's transmission tariff for network charges are those facilities that are part of the integrated network, which is designed to meet the loads within the balancing authority. FERC and the state utility commissions are continually monitoring the separation of distribution and transmission assets and the associated costs. This oversight ensures that only the costs of facilities that are used to deliver energy over the network at least cost under high standards of reliability are included in the utility's network tariff charges.

WPAG contends that BPA should distinguish between transmission used to serve generation integration function exclusively and transmission used for other purposes. (WPAG, ASC0008 at 3.) This suggestion, however, would reintroduce the divisive "definitional problem" of what facilities constitute "generation integration" that caused BPA to originally adopt the compromise on transmission in 1984. *See* 1984 ASCM ROD at 41-43. Attempting to specify which facilities serve solely "generation integration" functions would be immensely difficult and a huge burden on the administrative process of determining ASCs. This job would become even more difficult as more and more transmission facilities are assigned to a utility's integrated network, which by definition, serves multiple purposes. Even if BPA could define the term "generation integration" today, there would be no guarantee that this definition would be accurate in later years. The more reasonable and simpler approach is to remove the complication of defining "generation integration" and allow all transmission costs in ASC.

WPAG also asserts that BPA's proposal allows in ASC the costs of transmission facilities that serve "other purposes" unrelated to the acquisition of resources for the exchanging utility. (WPAG, ASC0008 at 3.) BPA acknowledges that its proposal may allow transmission costs into ASC that may not solely serve the load needs of the utility. The effects of including such transmission costs will have on the overall ASCs, however, should be minimal. The proposed ASC Methodology requires exchanging utilities to include as a credit to their ASC the revenues the utility receives as a result of these "other purposes." These revenue credits tend to neutralize most if not all of the costs of transmission facilities that serve other purposes than bringing a utility's resources to its load. Finally, the significant cost and time of administering a policy to exclude these costs, and resolving disputes relating thereto, reduces any benefit of excluding them. A utility's ASC, consequently, should not be significantly affected by the presence of a modest amount of transmission facilities that may serve other purposes.

Decision

BPA will include all transmission costs in ASC. BPA will also individually propose and support in its rate proceedings to include "symmetrical" transmission costs in its PF Exchange Rate.

4.10 Other

4.10.1 Cost Of Service Analysis (COSA) Requirement

Issue

Whether BPA should retain the requirement in the proposed ASC Methodology that requires COUs to submit a detailed Cost of Service Analysis (COSA) prepared by an accounting or consultant firm, approved by the governing board and used to set retail rates.

Parties' Positions

WPAG argues BPA has not justified its requirement that COUs produce COSA tables that are prepared by an accounting or consulting firms. (WPAG, ASC0008 at 7.) It claims that requiring COUs to provide these tables is an unnecessary expense, and adds nothing to the accuracy or veracity of the resulting study. (*Id.*) WPAG also complains that there is no comparable requirement for IOUs. (*Id.*)

BPA's Position

BPA must be able to verify that the financial information COUs enter into the ASC templates is accurate and a reasonable projection of the utility's cost of operations during the period of time covered by BPA's rate case. COUs are not subject to the same regulatory and financial reporting requirements as IOUs, so requiring an independent accounting or consulting firm to prepare the COSA tables is a prudent means of substantiating the information used to calculate the utility's ASC.

Evaluation of Positions

Verifying the accuracy and reliability of financial information provided by the COUs is a key concern of BPA. The financial reporting requirements of COUs are dramatically different than those required of IOUs. A minimal level of review by an independent accounting or consulting firm would be useful in eliminating errors and omissions in the COUs' filings prior to being submitted to BPA for an ASC determination.

WPAG claims it has no objection to providing BPA with the cost of service study used to set retail rates, or to the requirement that such cost of service study be approved by the governing body. (WPAG, ASC0008 at 7.) It, however, sees no reason to require that a consultant or accounting firm prepare such document. (*Id.*) WPAG claims this imposes an additional, unnecessary expense on the participating utility, and adds nothing to the accuracy or veracity of the cost of service study. (*Id.*) WPAG also comments that no comparable requirement is imposed on the documentation provided by participating IOUs, so it is unfair and unnecessary to impose such a requirement on preference customers. (*Id.*)

BPA included the verification requirement in its original proposal in order to ensure that a high level of accuracy and reliability is inherent in the financial information COUs file with BPA in the ASC review process. Without this requirement, BPA would have no way of knowing whether the COSAs submitted by the COUs are a materially correct and reasonable projection of their costs of operations going forward that will be collected in the rates charged retail customers. BPA could, of course, request that the COUs provide all documentation supporting every number in their COSA tables during the discovery portion of the ASC review period. This approach, however, would greatly increase the administrative burden of the ASC Review process and expand BPA's oversight duties beyond merely checking the COUs' compliance with the ASC Methodology.

WPAG argues that requiring an accounting or consulting firm to prepare the COSA puts an unnecessary expense on the participating utilities and adds nothing to the accuracy or veracity of the COSA. (WPAG, ASC0008 at 7.) These entities are required to present audited financial statements as part of the information contained in "Official Statements" when issuing bonds to the public or in obtaining credit from local financial institutions. Official Statement information and credit lending application information require submission of historical utility rate information and load information to assess credit worthiness and debt repayment. Once an entity has assembled this financial information and has engaged the services of independent accounting and consulting firms, the incremental cost associated with the preparation and review of COSA information is usually quite small. BPA is unaware of any bank or lender that would loan money to a utility without the requirement of providing audited financial statements. Thus, the potential burden on the COUs in providing these COSAs is likely not to be as great as WPAG suggests.

Nevertheless, BPA recognizes that requiring an accounting or consulting firm to prepare the *entire* COSA may not be necessary to substantiate the accuracy of the financial information. Instead, as a compromise, BPA is willing to allow COUs to present a COSA table that has been reviewed by an accounting or consulting firm for the ASC Review process. Specifically, the COUs will be required to present COSA Statements that are accompanied by a statement prepared by an independent accounting or consulting firm outlining the scope of the review such firm performed along with a statement that the COSA represents a reasonable projection of the operating costs of the utility that will be collected in rates from the utility's customers and for the period of time covered by BPA's rate case.

WPAG's second point that these reviews would not add to the accuracy or veracity of the COSA, is not convincing. If the COSAs prepared by the COUs must undergo review by an independent accounting or consulting firm, it follows that the chances of catching errors and omissions greatly increases. Reviews would, therefore, add tremendous value to the accuracy and veracity of the COSAs submitted by the COUs. Furthermore, requiring the COUs and their auditors or consultants to resolve these issues prior to submitting the financial information for ASC Determinations will improve the efficiency of the ASC Review process, and limit the scope of BPA's role to administering the ASC Methodology.

Finally, WPAG complains that no comparable requirement is imposed on the documentation provided by participating IOUs, so it is unfair and unnecessary to impose such a requirement on preference customers. (WPAG, ASC0008 at 7.) WPAG's complaint is incorrect. BPA does not need to impose a requirement that the IOUs have their financial information from the FERC Form 1 audited and reviewed by an independent accounting firm in the ASC Methodology because *FERC* already requires it. *See* 18 C.F.R. §§ 41.10-11. The Commission's regulations require utilities to obtain an independent certified accountant to "test compliance in all material respects of those schedules as are indicated in the General Instructions set out in the Annual Report, Form No. 1, with the Commission's applicable Uniform System of Accounts and published accounting releases." *Id.* The CPA must file a Report of Certification, also referred to as the CPA Certification Statement, within 30 days after the electronic filing date of the FERC Form 1. *Id.* at § 41.11. Because the IOUs already have this requirement under the Commission's regulations, there is nothing "unfair" with BPA's requirement that COUs provide BPA with COSA Statements described above.

Decision

BPA will require exchanging COUs to file COSA tables that have been either "prepared or reviewed by" an independent accounting or consulting firm along with an accompanying statement prepared by the reviewing entity that outlines the scope of its review, and a statement that the COSA represents a reasonable projection of the utility's operating costs that will be collected in rates from the utility's customers, and a statement that the review is for the period of time covered by BPA's rate case.

4.10.2 Cost of Debt

Issue

Whether BPA should use its own cost of debt rather than the utility's cost of debt in determining ASC.

Parties' Positions

PPC/NRU argues that the ASC should not include the IOU's actual cost of debt, but BPA's cost of debt. (PPC/NRU, ASC0006 at 13.) This approach, according to PPC/NRU, avoids incremental risk-taking behavior by exchanging utilities. (*Id.*)

BPA's Position

The cost of debt used in the weighted cost of capital for IOUs will be the weighted cost of debt from the Utility's FERC Form 1 filing.

Evaluation of Positions

BPA proposes to use the weighted cost of debt from the IOUs FERC Form 1 filings in the weighted cost of capital section of the ASCM.

PPC/NRU argues that some portion of the cost of debt incurred by IOUs is driven by the risk profile of the utility. (PPC/NRU, ASC0006 at 13.) In financial terms, there is a "risk-free" component of the cost-of-debt and a "risky" component that is utility-specific. (*Id.*) According to PPC/NRU, this risk profile is not entirely exogenously determined, but results from actions taken by the utility and decisions made by its regulators. (*Id.*) Some of these actions and decisions drive up the risk profile of the utility, and thus the cost of debt. (*Id.)* PPC/NRU recommends that the ASC Methodology not encourage incremental risk-taking behavior because of the expectation that some of that risk will be "regionalized" via the REP. (*Id.*) In order to reduce the incentive for risky activities, PPC/NRU suggest that ASC not include the actual cost of debt of an IOU, but rather BPA's cost of debt. (*Id.*)

BPA disagrees with PPC/NRU that the ASC should replace the IOUs cost of debt with the BPA cost of debt. The REP program cannot effect or encourage incremental the risk-taking behavior of the IOUs because REP benefits flow directly through to the residential and small farm customers of the IOUs and do not affect IOU profits. In addition, nothing in the Northwest Power Act requires, or specifically authorizes, BPA to treat investor-owned utilities like BPA, who is able to finance resources without issuing common equity and can obtain Treasury bonds or government-secured debt. As noted above, the Administrator's discretion to determine the cost of resources was affirmed by the Commission in its order approving the 1984 ASC Methodology.[14] Also, Section 5(c) of the Northwest Power Act does not specifically authorize the Administrator to encourage or discourage IOU risk taking behavior. In fact, Section 5(c) is silent on the subject.

Decision

BPA will have the cost of debt used in the weighted cost of capital section of the ASCM for IOUs be the weighted cost of debt from the Utility's FERC Form 1 filing.

4.10.3 Cash Working Capital

Issue

Whether BPA should continue to include one-eighth of total exchangeable O&M costs, less fuel and purchase power costs, as Cash Working Capital (CWC) in ASC.

Parties' Positions

PPC/NRU states CWC must be functionalized before it is included in ASC, and only CWC for the Production function should be allowed in ASC. (PPC/NRU, ASC0006 at 12-13.)

The WUTC supports BPA's proposed treatment of CWC. (WUTC, ASC0005 at 23-24.)

BPA's Position

Cash Working Capital (CWC) is a component in almost all Regulatory Body determinations of rate base. BPA's proposal includes CWC as an element of rate base, which is consistent with the principle that investors receive a fair return on investment that is used, useful and devoted to public service.

Evaluation of Positions

CWC is a component in almost all Regulatory Body determinations of rate base. Inclusion of CWC as an element of rate base is consistent with the principle that investors receive a fair return on investment that is used, useful and devoted to public service. One definition of CWC as used in regulatory proceedings is:

> The average amount of capital provided by investors, over and above the investment in plant and other specifically measured rate base items, to bridge the gap between the time

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[14] 49 Fed. Reg. 39,293, 39,296 (Oct. 5, 1984):

> The Administrator was chosen to develop a methodology to determine ASC, subject only to the Commission's review.

> expenditures are required to provide services and the time collections are received for such services. [15]

Because the 1981 and 1984 ASC Methodologies relied on a jurisdictional approach, CWC was a part of the Utilities' rate base calculation in Regulatory Body rate orders. The 1981 and 1984 ASC Methodologies simply set an upper limit on the amount of CWC included in rate base for the ASC calculation.

Because the revised ASC Methodology proposes to use the Form 1 (which does not include a CWC value) as the basis for data for ASC filings, BPA believes it is important to include a separate determined value for CWC in the Utility's rate base calculation for ASC purposes. Although the determination of the proper amount of CWC in rate base is often very controversial, a standard and widely accepted measure is one-eighth of total O&M costs, less fuel and purchase power costs. This one-eighth formula was the cap or maximum amount that BPA allowed for CWC in the 1984 ASC Methodology.

The WUTC supports BPA's treatment of CWC in the ASC determinations. (WUTC, ASC0005 at 23-24.) The WUTC states that the method proposed by BPA is consistent with the "45-day" rule of thumb used by FERC. (*Id.)* Although there are a number of methods available for calculating working capital, such as lead-lag studies and investor-supplied working capital analysis, and some methods may be more appropriate than others depending on the context, the WUTC generally agrees that the method proposed by BPA is appropriate for the purposes of determining ASC. (*Id.)*

PPC/NRU, however, argues that this proposal, although a continuation of the 1984 ASC Methodology, ignores the possibility that some CWC is normally attributable to the Transmission and Distribution functions. (PPC/NRU, ASC0006 at 12-13.) PPC/NRU state that Schedule 1-A in Endnote f to the ASC Methodology includes CWC for the Transmission and Distribution functions. (*Id.*) PPC/NRU assert that CWC must be functionalized before it is included in ASC, and only CWC for the Production function should be allowed in ASC. (*Id.*)

BPA respectfully disagrees with PPC/NRU on this argument. PPC/NRU misinterprets the ASCM functionalization template. The CWC worksheet in BPA's ASCM template takes O&M costs from other sections of the template that have already been functionalized. For example, the line labeled 'Total Production O&M" on the CWC worksheet imports the value directly from the Expenses worksheet line with the same name. This value is placed in the production column of the CWC worksheet. The line labeled "Total Distribution O&M" on the CWC worksheet imports the value directly from the Expenses worksheet line with the same name. That value is placed in the Distribution column of the CWC worksheet. Thus, the ASCM Template does not functionalize CWC to Production. CWC is functionalized to Production, Transmission and Distribution based on the functional nature of individual components of CWC, and only the portions functionalized to Production and Transmission

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[15] G. Hahne and G. Aliff, Public Utility Accounting , page 5-4 (Mathew Binder 2005).

are included in ASC. It is appropriate to include the transmission portion of CWC in ASC because transmission-related costs are considered costs of resources in the proposed ASCM.

Decision

BPA will include CWC as an element of rate base, which is consistent with the principle that investors receive a fair return on investment that is used, useful and devoted to public service. The ASCM will include cash working capital for both the production and transmission functions.

4.10.4 Regulatory Assets and Liabilities

Issue

Whether regulatory assets and liabilities (RAL) should be reviewed by direct analysis.

Parties' Positions

PPC/NRU note that Account 182.3 (Other Regulatory Assets) and Account 245 (Other Regulatory Liabilities) are a new issue in the development of ASCs because they did not exist when BPA developed the 1984 ASCM. (PPC/NRU, ASC0006 at 12.) PPC/NRU note that BPA's proposal may or may not adequately mitigate the potential that RALs will be allowed (and adjusted) by state commissions in light of the ability of the net costs of such assets to be reduced by an increase in subsidies from BPA's preference customers. (*Id.*) PPC/NRU suggests that BPA retain its proposal to use direct analysis when evaluating RALs. (*Id.*)

The WUTC supports BPA's proposal to require exchanging utilities to conduct a direct analysis on RALs. (WUTC, ASC0005 at 22-23.)

BPA's Position

Direct analysis of RALs is necessary because the account information available from the FERC Form 1 is not sufficiently detailed to determine the functional nature of the costs and their proper treatment in the ASCM.

Evaluation of Positions

Under the proposed ASC Methodology, exchanging utilities are required to conduct a direct analysis on regulatory assets so the individual items included in regulatory assets or liabilities can be properly functionalized and included in the calculation of ASC. The utility must describe the functional nature of the regulatory asset or liability, whether or not the asset or liability is included in rate base by its state commission(s), and the return or carrying costs allowed by the state commission(s). Under no conditions would regulatory assets be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates.

PPC/NRU notes that the issue of whether RALs should be included in ASC is a new issue, because Other Regulatory Assets and Liabilities did not exist in 1984. (PPC/NRU, ASC0006 at 12) In this case, BPA's proposal may or may not adequately mitigate the potential that Other Regulatory Assets and Liabilities will be allowed (and adjusted) by state commissions in light of the ability of the net costs of such assets to residential ratepayers to be reduced by an increase in subsidies from BPA's preference customers. (*Id.*) Thus, according to PPC/NRU, Other Regulatory Assets and Liabilities create the same incentive problems as inclusion of ROE in ASC. (*Id.*) PPC/NRU asserts that functionalization of the RALs is not the only issue, although it is important. (*Id.*) PPC/NRU is concerned that state commissions will perceive incentives to allocate regulatory assets and liabilities in ways that maximize ASCs for purposes of the REP, irrespective of whether such assets and liabilities are actually included in residential rates. (*Id.*) The proposed changes in the ASC Methodology create such incentives. (*Id.*) Thus, PPC/NRU recommends that BPA retain the ability to exclude RALs, based on direct analysis. (*Id.*)

The WUTC supports BPA's proposal to require direct analysis on Other Regulatory Assets and Liabilities. (WUTC, ASC0005 at 22-23.) It notes that regulatory assets are a creature of regulatory decisions made by state regulators or FERC. (*Id.)* These assets represent costs a utility is allowed to book and recover in rates over a period of time, rather than expense in a particular period. (*Id.)* Nonetheless, these costs are real, known and measurable. (*Id.)* Recovery of regulatory assets typically includes recovery of carrying costs at a level approved by a state commission. (*Id.*) The WUTC states that although this approach is a departure from the general use of FERC Form 1 data, BPA's approach is provides appropriate flexibility. (*Id.)* For example, the WUTC states that BPA appropriately places the burden on the utility to demonstrate that these costs are appropriate to include in ASC and how they should be functionalized, based on the regulatory decisions that created the regulatory asset. (*Id.*)

BPA agrees the observations that PPC/NRU and the WUTC make in their comments. Other Regulatory Assets and Liabilities are a new aspect of the regulatory rate environment that is untested in the ASC context. For some utilities, RALs represent a significant amount of costs in the FERC Form 1. BPA cannot determine merely by looking at the FERC accounts the functional nature of a line item in the regulatory asset or liability accounts, or the regulatory treatment by state regulators. If BPA is to fulfill its responsibility of calculating an ASC that only includes the allowable costs specified in the ASC Methodology, it must require that exchanging utilities perform and BPA review a direct analysis on regulatory assets and liabilities proposed for inclusion in ASC. BPA, therefore, will maintain its proposal to require utilities to perform a direct analysis on RALs.

Decision

BPA will require each filing utility to functionalize Account 182.3 (Other Regulatory Assets) and Account 245 (Other Regulatory Liabilities) by direct analysis.

4.10.5 Distribution Loss Study

Issue

Whether BPA should require participating utilities to prepare and provide a current Distribution Loss Study with their Appendix 1 filings.

Parties' Positions

Parties had no comments on this issue.

BPA's Position

In the proposed ASCM, BPA required participating utilities to provide a current distribution loss study with their Appendix 1 filings.

Evaluation of Positions

Distribution loss factors are required to calculate the distribution losses to be included in both a utility's Contract System Load and its exchange loads. During the Expedite Review Process, BPA learned that a number of utilities do not have current loss studies. Because of the time and cost involved in preparing a loss study, some parties argued that it was not appropriate to require a current study to be prepared just for purposes of participating in the REP. In addition, some utilities could not complete a current loss study by October 1, 2008, when utilities will start billing BPA for actual exchange loads under the new REP.

In response to the concerns cited above, BPA is offering the following alternate method for determining a utility's distribution loss factor.

1. Calculate a 5 year average total system loss factor, using data from the base year plus the preceding 4 years. IOUs will use data from the FERC Form 1. COUs will use a comparable data source.

2. From this 5-year total system loss factor, subtract the loss factor for BPA's transmission system.

3. The resulting loss factor will be deemed to be the exchanging utility's distribution loss factor for calculating Contract System Load and exchange loads under the REP.

Decision

BPA will allow participating utilities to use the method described above to determine their distribution loss factors if they do not have a current distribution loss study.

4.10.6 Interpretation of ASC and Adjustments to Functionalization Codes

Issue

Whether the ASCM, which states the Administrator may interpret the Methodology, should clarify the ASCM's Appendix 1 instructions to allow BPA to add, remove or modify a functionalization code during ASC reviews in response to changes in the FERC Uniform System of Accounts.

Parties' Positions

No parties submitted comments on this issue.

BPA's Position

The proposed ASCM should contain a provision that acknowledges that the Administrator may issue interpretations of the ASCM, and should include clarifying language that provides for additions, subtractions, and modifications to functionalization codes in response to changes in the FERC Uniform System of Accounts.

Evaluation of Positions

During the ASCM consultation proceeding, BPA became concerned that the ASCM as proposed on February 8, 2008, did not provide the Administrator with enough flexibility to address minor issues that might arise as the Methodology is being implemented. These concerns became particularly evident to BPA during the expedited ASC review process, where BPA had to clarify several aspects of the proposed ASCM. This experience led BPA to propose two minor adjustments to the Methodology.

First, BPA proposes to add a statement in the Methodology that acknowledges that the Administrator may, from time-to-time, issue interpretations of the ASCM. Specifically, BPA proposes to add a new Section V to the Methodology which states simply: "The Administrator may, from time to time, issue interpretations of the ASC Methodology." By adding this section, BPA is not proposing to change the ASCM in any substantive way. Even without the added language, BPA would have the ability to interpret the Methodology. The ASCM is an administrative rule of BPA, and as such, BPA has the discretion to interpret its own rules. *See United States v. Alisal Water Corp.*, 431 F.3d 643, 652 (9th Cir. 2005). Adding the above-noted language, therefore, does not change either BPA's or any of the parties' substantive rights. It does, however, give all parties notice that BPA may use this form of administrative interpretation to aid in the implementation of the ASCM. This notice is important because, under the 1984 ASCM, BPA issued eight of these interpretations on issues as varied as in-lieu taxes, transmission plant, rebates, procedural matters, rate base issues, experimental rates, and others. Consequently, BPA believes it is prudent for the ASCM to acknowledge that BPA may use this form of administrative interpretation to clarify the ASCM. For these reasons, adding the language described above is a prudent measure that should assist BPA in implementing the ASCM in an efficient and expeditious manner.

As a corollary to BPA's ability to interpret the Methodology, BPA also proposes to include a minor revision to the Appendix 1 instructions that makes clear that functionalization codes may be adjusted under limited circumstances. The proposed ASCM contained provisions that would have allowed BPA to make adjustments to accounts for changes in the FERC's Uniform System of Accounts. In the Appendix 1 instructions, the proposed ASCM stated the following:

> [i]f the Commission Accounts are later revised or renumbered, any changes shall be incorporated into this form by reference, except to the extent BPA determines that a particular change results in a change in the type of costs allowable for REP purposes. In such event, BPA shall address the changes, including escalation rules, in its Review Process for the following Exchange Period.

Proposed 2008 ASCM, Appendix 1 at 1.

The proposed ASCM is based primarily on the FERC Form 1, which has its foundation on the Commission's Uniform System of Accounts. The Commission, from time-to-time, changes these accounts by adding new accounts, subtracting old accounts and redefining existing accounts. It is very likely that over the next twenty years the Commission will adopt changes to its accounting system, which will in turn flow through to the exchanging utilities that use the FERC Form 1. These changes may result in the creation of new FERC Form 1 accounts, modification of existing accounts, or the deletion of old accounts. An expeditious way to handle these adjustments is to acknowledge that the Administrator may add, subtract or modify functionalizations of accounts through the ASC Review Process in response to changes in the FERC Uniform System of Accounts. BPA, therefore, proposes to revise the language in the instructions to say:

> [i]f the Commission Accounts are later revised or renumbered, any changes shall be incorporated into this form by reference, except to the extent BPA determines that a particular change results in a change in the type of costs allowable for REP purposes. In such event, BPA shall address the changes, including escalation rates and whether to add, remove, or modify a functionalization code, in its Review Process for the following Exchange Period.

Without this clarifying language, BPA is concerned that there would be an ambiguity as to what changes could be proposed in the event FERC were to add, subtract or modify an account. Although the ASCM provided general guidance on this subject, the proposed minor revision provides greater clarification regarding the connection between changes in the Uniform System of Accounts and ASC determinations.

<u>Decision</u>

BPA will add a section noting the Administrator may interpret the Methodology, and add clarifying language in the Appendix 1 instructions providing that BPA may add, remove or modify a functionalization code in an ASC Review Process in response to changes in the FERC Uniform System of Accounts.

4.10.7 <u>ASC Methodology and Market-driven Approach</u>

Issue

Whether BPA is reversing industry wide trends toward market driven approaches.

Parties' Positions

WPAG argues that by reversing many of the decisions in the 1984 ASCM, BPA will be reversing an industry wide trend toward a market driven approach by substantially increasing the size of a regulatory subsidy program for its IOU customers. (WPAG, ASC0008 at 2.)

BPA's Position

BPA establishes and implements the REP as required by law, generally regardless of industry trends, although such trends may influence costs incorporated in ASC determinations.

Evaluation of Positions

WPAG argues that on many of the substantive issues that are the subject of this process, the proposed ASCM would turn back the clock to the 1982-84 period by reversing many of the changes that were made in the 1984 revisions to the ASCM. (WPAG, ASC0008 at 2.) By doing so, BPA will be reversing an industry wide trend toward a market driven approach by substantially increasing the size of a regulatory subsidy program for its IOU customers. (*Id.*) Ironically, BPA is doing so at the same time it is proposing to institute a more market driven rate and resource acquisition approach for its preference customers in the form of tiered rates. (*Id.*) BPA has offered no meaningful explanation for this contradictory approach to the treatment of its two largest customer groups. (*Id.*) Although WPAG claims BPA is "reversing an industry wide trend toward a market driven approach by substantially increasing the size of a regulatory subsidy program," WPAG has made no demonstration that the REP should be established based on a market driven approach. As FERC and the Court have recognized, the REP is not a typical power transaction. No power is actually sold. No transmission losses are incurred. The REP is a monetary program established to provide rate relief to residential and small farm customers of preference utilities and IOUs. Congress established the REP as an alternative means of access to the low-cost Federal base system, therefore BPA must implement the REP in accordance with the law, regardless of "trends." Just as BPA's 1984 ASC Methodology was not founded on responding to industry trends, the proposed ASC Methodology also is not founded on responding to industry trends. This is not to say that the REP is unaffected by industry trends. To the extent the costs used to establish ASC reflect such trends, the effect of such trends will be reflected in the costs. This is much different, however, than founding an ASC Methodology on such trends.

Decision

BPA's ASC Methodology is not required to be founded on industry trends, but such trends may affect the costs used to establish ASCs.

4.10.8 ASC Consistency with Tiered Rates

Issue

Whether the ASCM is consistent with BPA's approach to tiered rates for its preference customers.

Parties' Positions

PPC/NRU state that a significant issue with the ASC Methodology, and the REP generally, is that BPA is moving to a system of tiered power rates. (PPC/NRU, ASC0006 at 3.) Many preference customers will be developing resources on their own in lieu of purchasing power to meet load growth from BPA, so the PF rate or rates will not accurately reflect the total cost of generation used to meet preference customers' retail loads. (*Id.*) BPA's proposed revision to the ASC Methodology does not address this problem, and so is deficient. (*Id.*) Any revisions to the ASC Methodology must take into account the fundamental change expected in the way BPA does business with its preference customers. (*Id.*)

BPA's Position

BPA's Regional Dialogue Policy identified a need to ensure that BPA's establishment of tiered rates is properly reflected in the ASC Methodology. The proposed ASC Methodology contains provisions to address the adoption of tiered rates. BPA can always revise the ASC Methodology in order to address any problems implementing tiered rates.

Evaluation of Positions

PPC/NRU state that a significant issue with the ASCM and the REP generally, is that BPA is moving to a system of tiered power rates. (PPC/NRU, ASC0006 at 3.) Many preference customers will be developing resources on their own in lieu of purchasing power to meet load growth from BPA, so the PF rate or rates will not accurately reflect the total cost of generation used to meet preference customers' retail loads. (*Id.*) BPA's proposed revision to the ASC Methodology does not address this problem, and so is seriously deficient. (*Id.*) Any revisions to the ASC Methodology must take into account the fundamental change expected in the way BPA does business with its preference customers. (*Id.*) In an extreme case, preference customers could be acquiring resources on the margin to meet all of their own load growth (and to replace all of their retired resources), while at the same time subsidizing the acquisition of all new resources by the IOUs. (*Id.*) This was not a result contemplated by the Northwest Power Act, and it would be an extremely unstable outcome politically because preference customer residential rates could be rising more rapidly than IOU residential rates concurrent with a subsidy. (*Id.*) For this reason, PPC/NRU recommends that any changes in the existing ASC Methodology at this time be modest and temporary. (*Id.*)

PPC/NRU seriously misconstrues BPA's service obligations, Tiered rates, and the relation of both to the REP. In terms of service obligation, BPA is obligated only to serve preference customers load that a customer requests BPA to serve. The customer has always had the right or option to develop its own resources or choose to purchase power from a service provider other than BPA. Many BPA preference customers have done just that and in some cases, have themselves participated in the REP. Tiered rates in no way alters the customer's rights, or BPA's obligation regarding service under Section 5(b) of the Northwest Power Act. Rather, what tiered rates do change, purely as a matter of rate design, is the allocation of costs that, for the same service, would, prior to Tiered rates, have been melded. That melded rate would have reflected BPA's cost of serving preference customer load, all in accordance with the rate directive of section 7 of the Northwest Power Act. Tiered rates do no change that. They too will reflect BPA's costs of serving preference customer load, all in accordance with the rate directive of section 7. Tiered rates simply break out and allocate those costs between load that can be served with existing resources (with limited augmentation) and load that necessitates acquisition of additional resourece. Given the same amount of preference customer load placed on BPA, the total costs recovered from preference customers would be the same with melded or Tiered rates. From this standpoint, the conflict PPC/NRU posits does not exist.

At the same time, PPC/NRU raises a legitimate point regarding the possible impact of the REP on the PF rate in the event preference customers choose, as a consequence of Tiered rates, to rely on BPA considerably less to meet their load growth. They express concern that BPA's PF rate could be lower, resulting in more REP benefits and the consequent diminution in the value of the Tier 1 PF rate. At this point in time, due to the very significant uncertainty of what customers will do, BPA does not believe it is necessary to address this issue now. If implementation issues associated with interactions between Tiered rates and the ASCM become more apparent and real, particularly with respect to the treatment of load growth, it can be addressed in BPA's design of the PF rates and, if appropriate, the Administrator will start a reconsultation on the ASC Methodology.

Even though BPA is taking steps towards changing the manner in which it does business with its preference customers, BPA must ensure that it has an ASC Methodology ready to implement the REP. The 1984 ASC Methodology has been in place for 24 years and was developed in a radically different environment. Cost exclusions contained in the 1984 ASCM were not permanently sanctioned by the Court, yet have continued in effect for that 24 years, thereby reducing REP benefits. BPA has proposed specific changes in order to establish a lawful, efficient and reasonable Methodology. Nevertheless, BPA recognizes that the Methodology is being established in a period of change. That is why the manner in which the ASC Methodology interacts with BPA's tiered rate development can be changed. The proposed ASC Methodology contains provisions under which customers can ask the Administrator to revisit the ASC Methodology. Thus, significant changes can be made to the ASC Methodology for a myriad of reasons, but BPA can later revise the ASC Methodology to address any problems with its implementation.

Decision

BPA has properly developed the ASC Methodology to accommodate the adoption of tiered rates. If implementation issues associated with interactions between Tiered rates and the ASCM become more apparent and real, particularly with respect to the treatment of load growth, it can be addressed in BPA's design of the PF rates and, if appropriate, the Administrator will start a reconsultation on the ASC Methodology.

4.10.9 REP Payment Levels

Issue

Whether BPA is trying to establish REP benefits that approximate the payments made under the Subscription REP Settlement Agreements by reversing many decisions in the ASCM.

Parties' Positions

WPAG argues that it appears that BPA is driven to establish REP benefits that approximate the payment stream enjoyed by the IOUs under the Subscription Settlement Agreements and the subsequent amendments, and is willing to reverse many decisions that have been in place for more than twenty years. (WPAG, ASC0008 at 3.)

BPA's Position

BPA's proposed changes to the ASC Methodology unequivocally do not replicate the benefits provided the IOUs under the 2000 REP Settlement Agreements. BPA is proposing to change a 1984 ASC Methodology that contained cost exclusions the Ninth Circuit did not permanently sanction, and which has been in effect for 24 years despite radical changes in the electricity industry.

Evaluation of Positions

WPAG argues that it appears that BPA is driven to establish REP benefits that approximate the payment stream enjoyed by the IOUs under the Subscription REP Settlement Agreements and the subsequent amendments, and is willing to reverse many decisions that have been in place for more than twenty years. (WPAG, ASC0008 at 3.)

WPAG's comment is without merit. First, the ASC Methodology only determines the ASCs of exchanging utilities, not the amount of their REP benefits. Actual REP benefits are dependent in much larger part by the section 7(b)(2) rate test. The rate test can only be conducted in a section 7(i) hearing to establish BPA's rates and the REP must be implemented with whatever PF Exchange rate results from the separate administrative ratemaking proceeding. Thus, the ASC Methodology simply cannot be used, as WPAG suggests, to replicate the level of REP benefits under the REP Settlement because it is only one part of the determination of such benefits.

Second, when BPA entered into the 2000 REP Settlement Agreements, preference customers were aware that the IOUs' REP benefits could be quite substantial if the IOUs were to prevail on challenges to BPA's failure to revise the 1984 ASC Methodology and/or BPA's implementation of the section 7(b)(2) rate test. BPA's preference customers generally supported the initial REP Settlement Agreements, which significantly limited the REP benefits IOUs could receive. The REP Settlement Agreements were not challenged because they provided excessive benefits, but rather because later Load Reduction Agreements provided benefits to two IOUs that were perceived as excessive. Now that the 2000 REP Settlement has been held unlawful, WPAG feigns surprise when BPA revisits the ASC

Methodology and must revisit the dormant issues critical to implementation of the REP. The 2000 REP Settlement Agreements left significant REP issues unresolved which, when resolved, could significantly increase or decrease REP benefits. This should come as no surprise since there is no settlement that eliminates the need to deal with these issues. By addressing these issues now, BPA is not attempting to resurrect the value of the 2000 REP Settlement Agreements. Instead, BPA is performing its statutory duties in accordance with the law. If BPA's decisions increase REP benefits, they increase REP benefits. If BPA's decisions decrease REP benefits, they decrease REP benefits. BPA can only make such decisions in accordance with the law and the record.

WPAG argues the detrimental long-term consequences of any drive to increase REP benefits above a level never seen under the ASCM will be dealt with by preference customers for years to come. (*Id.*) WPAG's general assertion is unfounded. BPA does not currently know what level of REP benefits will ultimately result from BPA's ASC Methodology and ratemaking decisions because neither administrative process has been completed. . Also, BPA does not know whether the eventual level of REP benefits under the ASCM will be at a level "never seen" under the ASCM. No such analysis has been presented and such a result would be surprising. Regardless of whether such benefits are viewed as high or low, however, BPA can only make its decisions based on the law and the record. Administrative actions must be judged on the law and the facts. As BPA has demonstrated above, both support BPA's proposed ASC Methodology.

Decision

BPA's proposed changes to the ASC Methodology do not attempt to replicate the benefits provided IOUs under the 2000 REP Settlement Agreements.

4.10.10 ASC Decisions and Level of Benefits

Issue

Whether decisions in the ASCM are creating overly generous ASC Determinations for IOUs, putting COUs in the position of paying subsidies to neighboring private utilities that may already have lower residential rates.

Parties' Positions

PPC/NRU argue that the proposed ASC methodology runs the risk of having an irrational situation recur a third time, through overly generous ASC determinations for private utilities. (PPC/NRU, ASC0006 at 2-3.)

BPA's Position

BPA is proposing changes to the 1984 ASC Methodology that are consistent with the Northwest Power Act and are not overly generous. The effects of the REP on retail rates of adjacent customers are a consequence of properly meeting BPA's statutory obligations.

Evaluation of Positions

PPC/NRU argue that one of the principal reasons why PPC protested the 1981 ASC Methodology was the fact that numerous consumer-owned utilities had higher residential rates than adjacent privately owned utilities, putting consumer-owned utilities in the position of paying subsidies to neighboring private utilities with lower residential rates. (PPC/NRU, ASC0006 at 2-3.) This problem recurred under the invalid Subscription REP Settlement contracts where again across the Northwest consumer-owned utilities paid subsidies to adjacent private utilities with lower residential rates. (*Id*.) The proposed ASCM runs the risk of having this irrational situation recur a third time, through overly generous ASC determinations for private utilities. (*Id*.) While we are confident that a properly functioning rate test would blunt the impact of the new ASCM, the operation of the rate test should not serve as an excuse for adopting a flawed ASC methodology. (*Id*.)

BPA agrees that a properly functioning section 7(b)(2) rate test should not serve as an excuse for adopting a flawed ASC methodology. Indeed, BPA's development of the proposed ASC Methodology is not dependent on the results of any 7(b)(2) rate test. Instead, BPA's decision to revisit the methodology is based on the fact that the REP has not been implemented for *12 years*; the fact that the existing ASC Methodology is *24 years old*; the fact that the electric utility industry has undergone radical changes; the fact that the Court that reviewed the previous ASCM and did not sanction a permanent exclusion of certain costs; and the fact that very real concerns have been raised regarding the continuing legitimacy of the changes made in the 1984 ASCM. BPA is revising the ASC Methodology because it is time to revisit the Methodology and ensure it is working properly in the current environment and as intended by the Northwest Power Act.

BPA's customers receive certain benefits and certain obligations under the Northwest Power Act. BPA's preference customers receive rate benefits through section 7(b)(2) cost protection. Preference utilities and IOUs receive benefits under the REP. Direct service industrial customers received a right to initial long-term power sales contracts and subsequent service as determined by the Administrator. BPA must implement all of the requirements of the Northwest Power Act, which may have varied and interrelated impacts. BPA understands PPC/NRU's concern; however, the Northwest Power Act established specific directives regarding the REP and ratemaking. BPA must follow the law and cannot artificially suppress the proper implementation of the ASC Methodology in order to benefit adjacent preference customers.

Decision

BPA's proposed ASC Methodology complies with the Northwest Power Act and provide only such REP benefits as are proper under the law.

4.10.11 Justification of Proposed ASCM Changes

Issue

Whether BPA has justified proposed changes to the ASCM.

Parties' Positions

PPC/NRU argue that in proposing changes to the ASCM, BPA has provided either inadequate or no justification; in some cases, the proposed changes contradict the purposes and limitations on the program as established in the Northwest Power Act. (PPC/NRU, ASC0006 at 4.)

BPA's Position

BPA has properly justified its proposed changes to the 1984 ASC Methodology, and BPA will be receiving additional comments regarding the proposed changes that will supplement the record in this proceeding.

Evaluation of Positions

PPC/NRU argue that in its Federal Register Notice in this proceeding, BPA proposed several changes to the 1984 ASC Methodology, which collectively serve to increase the IOUs' ASCs compared with the 1984 Methodology and thus increase the benefits paid by BPA's preference customers (except to the extent overall benefits are limited by the rate test). (PPC/NRU, ASC0006 at 4.) PPC/NRU correctly note that some of the changes proposed by BPA would, all else being equal, increase exchanging utilities' ASCs. This is true, however, not just for exchanging IOUs, but also for exchanging *preference* customers. The ASC Methodology applies equally to all utilities, regardless of structure. Although higher ASCs can result in higher REP benefits/costs, PPC/NRU necessarily qualified their statement by acknowledging that the REP benefits for exchanging utilities are controlled by the section 7(b)(2) rate test. Indeed, the rate test is a much more significant constraint on REP benefits than changes to BPA's ASC methodology. Indeed, the section 7(b)(2) rate test has consistently provided preference customers significant protection from numerous costs of the Northwest Power Act and will likely continue to do so for many years. The fact that preference customers pay some of the costs of the REP is prescribed by law. BPA is not imposing any costs on preference customers that do not arise from the proper implementation of the Northwest Power Act.

PPC/NRU argues that BPA's proposed changes to the 1984 ASC Methodology are not adequately justified; in some cases, the proposed changes contradict the purposes and limitations on the program as established in the Northwest Power Act. (*Id.*) PPC/NRU's accusation, however, is inaccurate. BPA only provided a brief explanation of its rationale in its original FRN. Since then, BPA has explained on numerous occasions through a number of workshops its position. Even more, any such claim is refuted by this record, beginning with BPA's Federal Register Notice and proceeding to the final comments BPA will receive on the proposed ASC Methodology. Furthermore, when such a claim is made, a party should identify where the agency's proposed changes are unsupported. This allows the agency to review the record and its rationale and determine whether it has proposed a correct position. PPC/NRU does not specify any changes where justification is lacking. It is obviously difficult for an agency to respond to such sweeping, unidentified claims. As it stands now, BPA is unaware of any provision of the proposed ASC Methodology that is contrary to the Northwest Power Act. Indeed, BPA believes the revised ASCM is entirely consistent with The Act. Again, PPC/NRU has not identified any specific elements of the proposed ASC methodology that are allegedly unlawful. To the extent that PPC/NRU's general assertion is directed at a specific aspect of BPA's proposal, BPA has already responded above.

Decision

The elements of the proposed ASC Methodology have been fully justified and are consistent with the Northwest Power Act.