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

2008 AVERAGE SYSTEM COST METHODOLOGY

FINAL RECORD OF DECISION

June 2008

BONNEVILLE POWER ADMINISTRATION

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

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Table of Contents

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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
CHWM	Contract High Water Mark
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	Gigawatt-hour
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
PRC	Power Resources Cooperative
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) established 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, establishing new data sources from which ASCs were to be derived, and changing the nature and timing of BPA's procedures for review of ASC filings by utilities participating in the REP. BPA announced these proposed 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. On May 29, 2008, BPA published a revised version of the ASCM. BPA's response to the public comments and an explanation of the proposed revisions to the ASCM were described in an accompanying Draft Record of Decision (Draft ROD). Comments on the revised ASCM and the Draft ROD were accepted until June 12, 2008.

This Record of Decision describes the Administrator's final decisions on the 2008 ASCM and provides responses to the comments received 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] 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," (REP) there is generally no power transferred either to or from BPA.[2] "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, although BPA's preference customers may also participate in the REP. The REP is the mechanism that calculates the level of the benefits for the exchanging utilities. *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 is sold by BPA to preference customers and exchanging utilities at the PF rate (subject to section 7(b)(2)), "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 authority to determine each exchanging Utility's ASC on the basis of a methodology established in consultation proceedings. 16 U.S.C. § 839c(c)(7). Section 5(c)(7) states:

> 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

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[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).

[2] 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. *See* 16 U.S.C. § 839c(c)(5).

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) the 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 ASCM 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 ASCM 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 ASCM 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 file the BPA-determined ASC with FERC for review and approval. BPA determines a Utility's REP payments 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, BPA's PF Exchange rate has been lower than exchanging utilities' ASCs under the 1984 ASCM. The resulting monetary benefits paid to participating utilities are described as the "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 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 (FBS) 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 resource 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 ASCM 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 ASCM 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 exchanging 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 1981 following the signing of the Northwest Power Act into law in 1980. The 1981 Average System Cost Methodology (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 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 agreement that resource cost data would be based on information obtained from the state regulatory agencies (known as the "jurisdictional costing approach"), agreement on 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 ASCM. A public comment forum concerning the proposed ASCM was held on July 8, 1981, at BPA headquarters in 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 ASCM.

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) (now PacifiCorp) 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's 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 ASCM on August 26, 1981, in a Record of Decision ("1981 ASCM ROD"). That decision was based on a settlement agreement that had resolved nearly all issues raised by parties in the consultation proceeding. On October 14, 1981, FERC granted interim approval to the 1981 ASCM. *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 ASCM 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 ASCM, exchanging utilities filed an Appendix 1[3] with BPA "for each jurisdiction in which it desires to exchange power with BPA." 1981 ASCM ROD at 9. 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 Utility to file an Appendix 1 with BPA "each time it files for a jurisdictional rate change or otherwise commences a rate change proceeding" 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 during the course of a retail rate proceeding in each jurisdiction they served. 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 to FERC for review and approval. Docket No. RM81-41-000 Order No. 337 at 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 ASCM, which required only that BPA's review "be as prompt as possible." *See* 1981 ASCM ROD at 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 ASCM 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 ASCM, 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 contain the specific numbers necessary for ASC computation. In such instances, values for ASC accounts had to be imputed.

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[3] Appendix 1 refers to the appendix to the ASC Methodologies containing the form on which exchanging utilities report their cost of resources (known as "Contract System Cost") and other information required for the calculation of ASC.

Another drawback to the jurisdictional approach was that state rate regulators were not responsible for enforcing the requirements of 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 rates 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. To monitor whether the Utility was imprudently increasing its costs, however, would require BPA to become familiar with the utilities' state retail filings.

The need to have access to this underlying state retail filing information became ever more important as concerns of abuse emerged in the ASC reviews. Because costs approved by the state regulatory agency for retail ratemaking purposes were used as the basis for the ASCs under the 1981 ASCM, any cost included by the state Regulatory Body would generally be included in the exchanging Utility's ASC. This meant that if a Utility's state regulator allowed in the costs of terminated plant, it would become part of the Utility's ASC, which is expressly prohibited by the 1981 ASCM and 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, BPA engaged in a detailed 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 yet 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).

The alleged abuses and irregularities in the ASCs filings of the exchanging utilities prompted BPA's DSI customers to invoke their rights under Section IV of the Methodology to request a consultation process be held on the 1981 ASCM. BPA's public agency customers also requested that a new consultation proceeding be commenced. In response to these requests, on October 7, 1983, BPA initiated the 1984 ASCM consultation proceeding with the publication of 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 ASCM.

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 ASCM. 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 a final Record of Decision for the 1984 ASCM 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

Like the 1981 ASCM, the 1984 ASCM (1984 ASCM) required utilities to file with BPA an Appendix 1 form that contained cost information based on rate orders from state Utility Commissions or consumer-owned Utility governing bodies. BPA reviewed each Appendix 1 for conformance with criteria specified in the Methodology. *See* 18 C.F.R. § 301.1. Unlike the 1981 ASCM, however, the 1984 ASCM established elaborate procedures for reviewing and evaluating ASCs. Most importantly, the Appendix 1 filings were reviewed in a 210-day review process that started whenever the exchanging Utility implemented a change in retail rates. Not later than 80 days after a Utility filed a new Appendix 1, Regional Power Sales Customers or their designee could submit written challenges to costs included in the Utility's Contract System Costs. Not later than 90 days following the date the Utility filed its revised Appendix 1, BPA mailed to the Utility and all parties a list of issues or challenged costs concerning the Utility's revised Appendix 1 and requested comments from all parties. Written comments on the issues list from all parties were due 30 days after the issue list was filed. Parties could submit cross-comments in response to comments on the issues list up to 15 days after the written comments were submitted. Parties could request oral argument before the Administrator or the Administrator's designee up to 150 days after a Utility filed a new Appendix 1. BPA also had the right under the 1984 ASCM to issue a notice to parties requesting comments on costs that had not been challenged previously, on Contract System Loads[4], and other issues not raised previously. Comments from parties on such notice were due 150 days after a Utility filed a new Appendix 1. Written cross-comments in response to comments on the BPA notice were due 165 days after a Utility filed a new Appendix 1.

If BPA granted a request for oral argument, such argument was presented up to 180 days after a Utility filed a new Appendix 1. BPA was required to issue a final determination on the revised Appendix 1 no later than 210 days after a Utility filed a new Appendix 1.

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

Consumer-owned utilities could execute Residential Purchase and Sale Agreements (RPSAs) for participation in the REP. Because consumer-owned utilities were not regulated by the state Commissions in the Pacific Northwest, preparation and review of ASC filings was 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 ASCM made several changes to the 1981 ASCM. First, as noted above, it established a formal ASC review process with a 210-day timeline for review of utilities' ASC filings. Second, the 1984 ASCM made several substantive changes to the types of costs that would be allowed in ASC. The most significant changes were to the treatment of transmission, taxes, and return on equity. Transmission plant costs, which previously had been allowed in ASC without reservation, were limited to what was in service as of July 1, 1984, plus any additional cost of new transmission plant placed in service after July 1, 1984, if it was used to integrate generation resources into the exchanging Utility's grid, or the sum of new transmission plant 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. *See* 1984 ASCM ROD at 42-43. Return on equity was also removed from the determination of an exchanging Utility's ASC largely because a state commissioner had 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 utilities' ASC filings. Finally, Federal income taxes were also excluded from the calculation of exchanging utilities' ASCs.

[4] This refers to the total regional retail load of the exchanging utility.

2.3.4 Legal History of 1984 ASC Methodology

The IOUs and state commissions vigorously opposed the 1984 ASCM. They filed several lawsuits that attempted to enjoin or otherwise prohibit BPA's creation and implementation of the 1984 ASCM. *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 ASCM 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 ASCM 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 paid to the IOUs under the REP.

FERC approved the 1984 ASCM, 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 expressed 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. *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 ASCM. *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 ASCM, including the decisions to exclude taxes and return on equity from ASC. *Id.* However, in sustaining BPA's decision to adopt the 1984 ASCM, 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 ASCM.

Id.

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

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

As noted above, the 1984 ASCM continued the use of jurisdictional filings to calculate ASCs. This approach required BPA to rely on state regulatory agencies to determine the level of costs included in the ASC. Although providing BPA access to more detailed information, the jurisdictional costing approach also resulted in long, burdensome, expensive and often contentious review processes. The 210-day review period for each ASC filing under the 1984 ASCM meant that during its implementation BPA and its customers were almost always reviewing an ASC filing. This burden was further compounded by the volume of Utility rate orders. Because any commission-ordered change in retail rates triggered a new ASC filing under the 1984 ASCM, BPA and its customers were faced with reviewing several ASC filings a year for each Utility participating in the REP. This administrative burden continued to grow as utilities adopted adjustment clauses to allow for automatic changes to rates in each state where the utilities provided retail electric service.

BPA's ASC determinations under the 1984 ASCM were very contentious. This derived in part from the IOUs' objections to the implementation of the 1984 ASCM, which they continued to view as seriously flawed. Dozens of BPA's ASC determinations were contested before FERC. *See, e.g., Pacific Power & Light, dba PacifiCorp*, 37 FERC ¶ 61,105 (1986); *Idaho Power Company*, 37 FERC ¶ 61,104 (1986); *Utah Power & Light Co.*, 39 FERC ¶ 61,002 (1987); *Puget Sound Power & Light Co.,* 56 FERC ¶ 61,124 (1991). Some ASC disputes were resolved by the Ninth Circuit. *See Wash. Util. & Transp. Comm'n v. FERC*, 26 F.3d 935 (9th Cir. 1994); *CP Nat. Corp. v. Bonneville Power Admin.*, 928 F.2d 905 (9th Cir. 1991). Due to the burdensome, expensive and often contentious nature of implementing the 1984 ASCM, BPA worked with exchanging utilities to develop REP settlement agreements, which resolved REP disputes 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 these settlements with exchanging utilities, BPA did not conduct formal ASC reviews under the 1984 ASCM for purposes of establishing REP benefits from 1998 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

In early 1997 BPA 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 executive branch, 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 product and pricing principles. BPA also proposed to develop a Power Subscription Strategy.

BPA's Subscription Strategy was a comprehensive BPA business plan that addressed many details regarding service for all of BPA's customer classes: COUs and other 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 forecast 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 REP Settlement Agreements. At the conclusion of this public process, BPA published its final Subscription Strategy and Record of Decision on December 21, 1998.

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 resulted in a Supplemental Subscription Strategy and 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 regional State commissions and proposed by BPA. BPA's allocation received support from diverse customer and interest groups: COUs, IOUs, the regional State regulatory commissions, state agencies, and a city commission.

2.5.4 2000 REP Settlement Agreements and RPSAs

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 the REP Settlement Agreements. During this comment process, several of the IOUs requested that BPA not use its 1984 ASCM 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 consultation process to revise the ASCM. *Id.* BPA decided not to formally commence the process of adjusting the ASCM, but agreed to "informally discuss possible revisions." *Id.* at 24.

The need to have informal discussions on revising the 1984 ASCM, however, became less important as 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. With the primary beneficiaries of the REP agreeing to the REP Settlement Agreements, and no consumer-owned utilities requesting a new consultation process, BPA decided to postpone any further discussions on revising the 1984 ASCM.

2.5.5 *Portland General Elec. Co.* and *Golden NW Aluminum* Decisions

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 (the Court). 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. *See 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 began this consultation proceeding to revise the ASCM.

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 ASCM. These discussions began on August 1, 2007, when the Administrator initiated the first of many public meetings in which informal comment was taken on issues pertaining to the 1984 ASCM. On August 22, 2007, BPA held a follow-on workshop to consider various ASC issues and to begin exploring future ASC options, including potential changes.

On September 10, 2007, BPA held another workshop to discuss a BPA "straw" proposal that included attributes of a revised ASCM. 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 regarding the ASCM. 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.

BPA held a public working session on a proposed ASC filing template on October 16, 2007, followed on October 22, 2007, by another public workshop to discuss a proposed construct for the ASCM. 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 Utility 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 COUs presented comments in response to BPA's request for feedback on the ASCM. BPA held another public workshop on November 15, 2007, to discuss ASC issues.

Following the close of the informal workshops, on February 7, 2008, BPA published in the Federal Register (73 Fed. Reg. 7270, February 7, 2008), a proposed ASCM. The proposed ASCM, based in large part on public comment, redefined the types of capital and expense items includable in ASC, established new data sources from which ASCs would be derived, and changed the nature and timing of BPA's procedures for review of ASC filings by utilities participating in the REP. The Federal Register Notice (FRN) also contained detailed procedures for public participation in the consultation proceeding. The FRN solicited a new round of formal written comments from interested members of the public and provided for a comment period from February 8, 2008, through May 2, 2008. The notice also included a procedural schedule for taking official comments in the formal consultation proceeding. The schedule allowed numerous opportunities to comment as well as multiple opportunities to discuss matters with BPA staff in public workshops, all of which were specifically designed to facilitate the compilation of a full record upon which the Administrator would base a decision to establish a new ASCM.

Although preliminary informal comments had already been made by some groups and members of the public, the FRN initiated the process to receive formal comments on the proposed ASCM. 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.

The February 7, 2008, Federal Register also announced the commencement of an ASC expedited review process (Expedited Process). As explained more fully below, the Expedited Process was created to enable BPA to develop preliminary ASCs under the proposed ASCM for purposes of REP cost assumptions in BPA's WP-07 Supplemental Rate Proceeding. BPA requires ASC forecasts to develop its rates. The February 7, 2008, FRN notified parties that in order to participate in the REP during FY 2009, a Pacific Northwest Utility was required to notify BPA by February 22, 2008, and intervene in the Expedited Process. Exchanging utilities were required to submit an ASC filing (an Appendix 1) to BPA by March 3, 2008. If the Utility failed to file, BPA would use the corresponding forecast Appendix 1 from its WP-07 Supplemental Power Rate Adjustment Proceeding as the base filing to determine the Utility's ASCs for FY 2009. The Expedited Process was a valuable tool in developing and testing, in concert with the region, an ASCM that would be legally sustainable, efficient, and durable over time.

BPA also conducted numerous public workshops and briefings to discuss the proposed ASCM. On February 12, 2008, BPA made a formal presentation to the Northwest Power and Conservation Council and sought the Council's comments on the proposed ASCM. BPA conducted public workshops, including those held on March 6, 13, 26, and 31 and April 16, 17, 18, and 23, 2008. 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 purchases from BPA 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 Service Commission (MPSC) 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 ASCM website (http://www.bpa.gov/applications/publiccomments/closedcommentlisting.aspx).

On April 18, 2008, early 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.

Interested members of the public were afforded an opportunity to make written comments throughout the consultation process. The first comment period began on February 8, 2008, and closed on May 2, 2008. By the close of the first comment period, BPA had received comments from a wide range of customer groups. Participants submitting comments included all six of the region's 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 COU customers, including the Western Public Agencies Group (WPAG), the Public Power Council (PPC), and the Power Resource Cooperative (PRC). Snohomish Public Utility District, BPA's largest COU customer, also filed comments.

On May 29, 2008, BPA posted a draft ASCM and Record of Decision (ROD) for public comment. Comments on the draft ASCM and ROD were accepted until June 12, 2008. A total of seven additional comments were received by the close of comment date. Most of the comments were from the same diverse group of parties described above, and reflected many of the same issues and comments addressed in BPA's Draft ROD. Some comments, however, raised new issues that will be addressed in this final Record of Decision.

3.2 Initial 2008 ASC Methodology

BPA's February 2008 proposed ASCM was intended to implement section 5(c) of the Northwest Power Act in a manner that alleviated much of the administrative burden and expense associated with the jurisdictional approach to ASC determinations. It also was intended to reflect changes in the organization and operation of the electric Utility industry since the 1984 ASCM was approved. *See, e.g.*, The Changing Structure of the Electric Power Industry 2000: An Update, October 2000, Energy Information Administration, United States Dept. of Energy. 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 ASCM, the proposal was not a complete reconstruction of the 1984 ASCM. Several portions of the proposal reflect features from the 1984 ASCM that remain viable in today's environment.

BPA proposed changes to a number of areas in the ASCM. The first area of change was in how cost data was collected for a Utility's ASC. Both the 1981 and 1984 ASC Methodologies used the jurisdictional costing approach for ASC determinations. Because the jurisdictional approach had proven to be inefficient, cumbersome, and extremely contentious, BPA did not include it in the revised ASCM. In its place, BPA proposed to use the FERC Form 1 (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 its wholesale power rates, referred to as the Review Period. An IOU 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 rate period (and for an additional four years as required for the section 7(b)(2) rate test) covered in BPA's wholesale power rate adjustment proceedings. 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, expected to be two years.

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

A third area of proposed changes concerned transmission investments and expenses. All transmission investments and expenses were included in ASC under the 1981 ASCM. In the 1984 ASCM, 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 42-43. BPA is proposing to remove these criteria and once again allow all transmission investment in the determination of ASC.

The 1984 ASCM did not allow return on equity in ASCs, but instead permitted the inclusion of a Utility's long-term cost of debt. Because of changes in the Utility industry over the past 24 years and based on BPA's experience in implementing the ASC, BPA proposed that Utilities should again be allowed to exchange return on equity.

Under the revised ASCM, 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 return on equity and taxes. If costs associated with equity return as a resource cost were included in the calculation of ASCs, an IOU's cost of resources would be understated if the cost of Federal income taxes at the marginal tax rate was not also included. Because BPA is proposing to include return on equity as a resource cost in the ASCM, BPA also proposed to gross up the equity component by the Federal income tax rate when determining an IOU's weighted cost of capital in ASC.

3.3 Expedited ASC Review Process

As noted earlier, in February 2008 BPA began a separate review process, called the Expedited Process, which was run in parallel to the ASCM consultation. BPA's purpose in conducting the Expedited Process was two-fold. First, BPA needed to develop forecast ASCs for its WP-07 Supplemental rate case that reflected, as closely as possible, the ASCs that would likely be in effect during the rate period. Because BPA had commenced a consultation process and was proposing numerous revisions to the ASCM, developing ASCs under the proposed ASCM was the most accurate way to forecast such ASCs.

Second, the Expedited Process would provide BPA and its customers with valuable insight into the practical application of the proposed ASCM. Developing ASCs under the procedural and substantive terms of the proposed ASCM would give BPA, and the exchanging utilities, a working understanding of both the benefits and limitations of the ASCM. The experienced gained through the Expedited Process could be used to identify ways to improve the proposed ASCM.

BPA notified parties of the Expedited Process in its February 7, 2008, Federal Register Notice. *See* 73 Fed. Reg. 7270 (February 7, 2008). In the FRN, 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 ASCM 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 Process was not limited to 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.

BPA will file its final ASCM and this Record of Decision with FERC for confirmation and approval. BPA hopes to receive interim approval of the ASCM in September 2008. BPA intends to review the ASC data resulting from the Expedited Process (which was based on the ASCM provisions from the February 7, 2008, Federal Register Notice) in the context of the final version of the ASCM submitted to FERC. If there are no differences between the data used in the Expedited Process and the Appendix 1s to be filed under the final Methodology, the Utilities' Expedited Process data will 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 ASCM criteria. Once BPA conforms the ASCs to the final ASCM, BPA will use the ASCs to develop final wholesale power rates for BPA's WP-07 Supplemental Rate Proposal. Although ASCs from the Expedited Process will be used in BPA's WP-07 Supplemental Rate Proceeding, BPA will require Utilities to file new Appendix 1s with BPA on October 1, 2008. These filings will then be subject to the review process prescribed in the new ASCM and used to implement the REP 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 a Utility's ASC 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 and 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.

WUTC argues BPA should eliminate this provision because it is unnecessary and superfluous, creates a potential for conflict with state or Federal law, and imposes an unfair penalty. (WUTC, ASC0005 at 6-9.) 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.*) WUTC states that 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.*)

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, WUTC states, 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, WUTC states, requests can be made to the WUTC for information included in rate proceedings. (*Id.*) WUTC claims that even confidential information may be obtainable under terms of protective orders. (*Id.*) Third, WUTC states that it and the exchanging Utility could be subject to discovery requests within the BPA proceeding to review ASC costs. (*Id.*)

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.*) WUTC states that BPA cannot by regulation grant a legal right to intervene in state rate proceedings that may be contrary to state law. (*Id.*)

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.*) WUTC states that it 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.*) WUTC states that it 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.*) WUTC notes that 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, WUTC cannot consider the interests of non-regulated entities that are not customers of the Utility. (*Id.*)

Finally, WUTC argues that BPA's proposed intervention provision could force 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.*) WUTC claims that 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.*) WUTC recommends that BPA delete the provision III(A) from the ASCM. (*Id.*)

BPA appreciates WUTC's thorough comments on this issue. As noted above, the WUTC suggests that 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 under the proposed 2008 ASCM 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. 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 is not creating a legal right to intervene in state rate proceedings, however, but instead 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 COU 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 serve only 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.

In its comments on the Draft ASCM ROD, PSE suggests the language of Section III(A) of the proposed 2008 ASCM should be further amended by inserting the words "(having made a good faith effort to intervene in such retail rate proceeding and having timely complied with applicable procedures to intervene in such retail rate proceeding)." (PSE, AS20009 at 2.) PSE claims this will prevent a potential intervenor in a retail rate proceeding from intentionally or in bad faith securing a denial of intervention and thereby unfairly invoking the remedy for denial of intervention. (*Id.*) Although BPA hopes that no party would employ the tactic PSE describes, PSE's suggestion may help to preclude such actions and should be adopted.

PPC disagrees with BPA's proposed amendment to Section III(A), which it claims does not go far enough to ensure, to the greatest extent reasonably possible, that BPA and its customers will be able to intervene in retail rate proceedings for the purpose of obtaining information relevant to an IOU's ASC. (PPC, AS20003 at 2.) PPC notes the amendment only provides that BPA *may* set the IOU's ASC equal to the PF Exchange rate, not that BPA *will* do so. (*Id*.) PPC claims that if BPA, or its customers, cannot intervene in IOU retail rate proceedings, it will become much more difficult, and potentially impossible, to determine whether the resulting return on equity, for example, is appropriate. (*Id*.) PPC argues the consequence of being denied party status in a retail rate proceeding should be that the IOU's ASC *will* be set equal to the PF Exchange rate. (*Id*.) PPC states the state commissions can still exercise their authority to decide whether or not to grant petitions to intervene. (*Id*.) BPA understands PPC's argument, however, the denial of intervention by a state commission is necessarily a factual determination that will rest on different facts in each case. BPA must evaluate the particular circumstances of any denial in order to ensure that such denial deserves the consequent penalty. In order to ensure that BPA's determination will be a reasonable one, BPA must reserve the right to review the specific facts. Although exceptions to the rule may be rare, it is necessary for BPA to retain the "may" language in the ASCM.

Decision

The ASCM will amend Section III(A) of the 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> (after having made a good faith effort to intervene in such retail rate proceeding and having timely complied with applicable procedures to intervene in such retail rate proceeding), 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 Right Of State Regulatory Commissions To Intervene In BPA's ASC Reviews

Issue

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

Parties' Positions

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

BPA's Position

BPA's proposed ASCM allows only BPA's Regional Power Sales Customers an automatic right to intervene in BPA's ASC review proceedings.

Evaluation of Positions

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.*) 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.*) WUTC suggests that BPA should include the state regulatory commissions in the BPA review process described in Section III(D) in the proposed ASCM. (*Id.*)

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), 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.*) WUTC recommends that Section III(D) be modified.

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

Decision

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

> *Any Regional Power Sales Customer <u>or state Utility Regulatory Body</u> 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, WUTC, PPC, IOUs and PSE 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; WUTC, AS20002 at 3; PPC, AS20003 at 3; IOUs, AS20007 at 2; PSE, AS20009 at 2)

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 ASCM. 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 ASCM, 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[5] 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.*)

[5] "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.

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 ASCM 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 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 ASCM 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*.)

In their comments on the Draft ROD, the WUTC, PPC, IOUs, and PSE all support BPA in the use of FERC Form 1 as the primary data source for ASC determinations. (WUTC, AS20002 at 3; PPC, AS20003 at 3; IOUs, AS20007 at 2; PSE, AS20009 at 2)

BPA agrees that FERC Form 1 should be the primary data source for Base ASC determinations.

Decision

The ASCM will use FERC Form 1 as the primary data source for Base 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 BPA 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

IPUC understands 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. (IPUC, ASC0003 at 2-4.) 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 IPUC recognizes that the schedule in this proceeding is expedited for the WP-07 case, it states that it believes that using the more recent 2007 data is justified. (*Id.*) IPUC notes that 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.*) IPUC states that 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.*) IPUC claims 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.*) IPUC states that each adjustment made to historical data increases the probability of disputes, problems, and delays. (*Id.*) IPUC argues that adjusting 2006 data to reflect 2007 changes, when actual 2007 data are available, will increase this risk unnecessarily. (*Id.)* IPUC states that 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's revised ASCM proposes to use 2006 data for the FY 2009 ASCs. 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, BPA will use the most recent FERC Form 1 when determining ASCs. BPA is attempting to synchronize its ASC determinations used for implementation of the REP and BPA's rate case ASC forecasts, which are used in forecasting REP benefits for ratemaking purposes. 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

The ASCM 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 Utilities should be able to be functionalize accounts in part by direct analysis and in part by a prescribed functionalization method. (IOU, ASC0004, at 1; IOU, AS20007 at 2-3.)

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. (IOU, 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 the FRN 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. As stated in the 1984 ASCM ROD:

> These methods should serve to mitigate significant cost assignment abuses inherent in the existing ASCM, 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 ASCM.

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. (IOU, ASC0004 at 1.) 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. (IOU, ASC0004 at 1.) The IOUs cite NorthWestern, which has costs in Account 303 that are 100 percent 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.

In their comments on the Draft ROD, the IOUs state their objective is not to "apply a functionalization ratio to costs already known to be ineligible," but rather to accurately allocate costs to Production, Transmission and Distribution/Other without unnecessarily imposing an excess burden on the filing Utility or BPA. (IOU, AS20007 at 3; PSE, AS20009 at 3.) The IOUs believe that the Utility should provide support for use of a functionalization ratio for items within an account. (*Id*.) The alternative is to create another (redundant) functionalization ratio for each item in an account that is appropriately allocated to more than one function. (*Id*.) The IOUs believe that being able to use a functionalization ratio for items within a FERC account is appropriate and will help to achieve BPA's goal of reducing the burden of establishing ASCs. (*Id*.)

BPA agrees with the IOUs that the use of functionalization ratios within accounts that require direct analysis can be appropriate. However, BPA believes it is necessary for the exchanging Utility to justify through direct analysis why the ratio adequately reflects the functional nature of the costs included in any account or cost item that is being functionalized by any ratio in an account that requires direct analysis.

<u>Decision</u>

The ASCM 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 Utilities to use a combination of direct analysis and a prescribed functionalization method for the same account. The Utilities can develop and use a functionalization ratio or use a prescribed functionalization method if the Utility through direct analysis can justify how the ratio adequately reflects the functional nature of the costs included in any account or cost item being functionalized by the ratio.

4.1.6 Single ASCs For Utilities With Multiple State Jurisdictions

Issue

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

Parties' Positions

WUTC supports the establishment of a single ASC for multi-state Utilities. (WUTC, ASC0005 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

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.) 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.*) WUTC notes that 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.*) WUTC states that 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.*) WUTC states that it 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, WUTC states that 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

The ASCM 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

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.) 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.)* 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

Although 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, the Commission suggests BPA should move the filing date to June 1 instead of May 1. (WUTC, ASC0005, 4-10.) Because utilities file FERC Form 1s with FERC each April, and because 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.*) WUTC's argument is well-reasoned and will be adopted.

WUTC supports BPA's proposal to allow utilities to update information contemporaneous with BPA's test-year. (WUTC, ASC0005, at 4-10.) 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, 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.*) 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 WUTC 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. 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 unnecessary and burdensome complexity. The proposed ASCM already requires ASC filings each year, with base ASC adjustments every two years. Such frequency provides relatively timely incorporation of data into BPA's ASC determinations. Accommodating changes for return on equity, Federal income taxes, debt costs, and short-term purchases and sales of wholesale power would create a much greater administrative burden for BPA and implementation burden for the exchanging utilities with unknown benefits. 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, the 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.

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 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.

Decision

The ASCM 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, or 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.) Snohomish also expresses concern regarding Utilities' termination rights under their RPSAs and the effect of such termination on deemer accounts. (Snohomish, AS20006 at 1.)

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.*) Snohomish states that to fix this loophole, BPA should revise the ASCM 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, 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 prepare 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 will not be required to include any proposed adjustments for resource changes or changes in service territories in the Appendix 1 filing.

In its comments on the Draft ASCM ROD, Snohomish states that in previous discussions with BPA, BPA has stated that there will only be one opportunity to execute an RPSA for the 2012-2028 period. (Snohomish, AS20006 at 1.) If a Utility fails to sign an RPSA, or terminates its RPSA, the next opportunity to re-enter the REP would be in 2029. (*Id.*) Snohomish seeks confirmation of this interpretation and states that other treatment would effectively eliminate any future deemer accounts, as utilities would be free to exit and re-enter the REP at will. (*Id.*) In response, BPA notes that this issue concerns the termination and deemer provisions of the RPSA. BPA is currently conducting a separate administrative proceeding for the development of the RPSAs, which is where such issues will be resolved. BPA understands Snohomish's concern, however, and if the deemer provision is retained in the RPSA, its operation should not be precluded by utilities' termination and re-entry rights. BPA notes, however, that the Northwest Power Act provides that "[w]henever a Pacific Northwest electric Utility offers to sell electric power to the Administrator at the average system cost of that Utility's resources in each year, the Administrator shall acquire by purchase such power and shall offer, in exchange, to sell an equivalent amount of electric power to such Utility for resale to that Utility's residential users within the region." 16 U.S.C. § 839c(c)(1). In summary, issues regarding utilities' rights to terminate their RPSA and later execute an RPSA to resume participation in the REP will be resolved in BPA's concurrent forum to establish new RPSAs.

Another issue that Snohomish's comment raises is the prospect that a Utility will delay executing an RPSA until the middle of a rate period. If that occurs, the proposed ASCM is silent on how that Utility's ASC would be determined. As noted earlier, utilities must file their ASCs with BPA by June 1 of the year *preceding* BPA's wholesale power rate case. These ASCs are then reviewed in an ASC review process, which occurs during the summer prior to the commencement of BPA's rate case. The resulting ASC determinations are then used in BPA's rate case to set rates. This approach is designed to provide stability and predictability to both the recipients of the REP benefits and the customers paying for the exchange. These objectives are achieved because the REP costs included in setting rates will, with the exception of exchange load variability, closely reflect the actual REP payments made by BPA through the rate period to the exchanging utilities.

The above construct, however, would not work if a Utility could enter the exchange within an Exchange Period but after the June 1 date, or during the subsequent Exchange Period. This is because if utilities were allowed to make ASC filings within an Exchange Period, the cost of the REP would increase beyond what BPA had assumed in the rate case. This would upset the stability and predictability of REP costs in rates that BPA is attempting to achieve with the procedural schedule detailed in Section II of the Methodology, although BPA acknowledges that actual REP benefits will not be identical to rate case forecasts. To avoid potential problems and abuses, BPA proposes to insert language into Section II.B.3 of the ASCM to make it clear that a Utility will not benefit by delaying its execution of an RPSA during the Review Period or the subsequent Exchange Period. In the original February 7, 2008, proposed ASCM, BPA included language which dealt with the scenario of a Utility that fails to file an Appendix 1 by the review deadline. This language stated: "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." This language was subsequently removed when BPA revised the proposed ASCM to respond to Snohomish's concerns. BPA now proposes to reinsert similar language into a new subsection in Section II.B.3 to deal specifically with the foregoing issues. This new section (II.D.1) will read as follows:

> *d. Failure to File an Appendix 1 Because of New Residential Purchase and Sale Agreement.* After the initial and second Exchange Periods, if a Utility fails to file its Appendix 1 by June 1 because it executed a Residential Purchase and Sale Agreement after the commencement of a Review Period or during the subsequent Exchange Period, then BPA may set the Utility's ASC equal to the PF Exchange rate until the end of the Exchange Period.

This language clarifies that if a Utility misses the June 1 deadline because it had executed an RPSA after the commencement of the ASC review process or during the subsequent Exchange Period, then it will receive no benefits until the following Exchange Period begins. This provision does not preclude the Utility from subsequently filing an Appendix 1 in accordance with the ASCM for the following Exchange Period.

Decision

The ASCM will state that if a Utility fails to timely file an Appendix 1 and refuses to cure the problem, BPA will prepare and file the Utility's Appendix 1 filing and the Utility will waive its right to participate in the ASC review process 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 will not be required to include any proposed adjustments for resource changes or changes in service territories in the Appendix 1 filing. The ASCM will also state that if a Utility fails to file its Appendix 1 by June 1 because it executed a Residential Purchase and Sale Agreement after the commencement of a Review Period or during the subsequent Exchange Period, then BPA may set the Utility's ASC equal to the PF Exchange rate until the end of the Exchange Period.

4.1.9 Consumer-Owned Utility 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 that 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 that 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 ASCM, 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. (WPAG, ASC0008, at 7-8.) WPAG suggests a 60-day notice period as a more realistic option. (*Id.)* BPA agrees that a 60-day notice period is reasonable for the reasons WPAG identifies.

Decision

The ASCM 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 ASCM in 2013 to assess whether the Methodology is fairly and accurately determining utilities' ASCs.

Parties' Positions

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

BPA's Position

The proposed ASCM includes provisions for revisiting the Methodology. These measures ensure a sufficient level of oversight and alleviate the need for a date certain to review the ASCM.

Evaluation of Positions

Snohomish states that BPA should commit to review the new ASCM 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 ASCM and that many of BPA's public power customers are concerned that these changes will increase the costs of the REP. (*Id.*) Snohomish believes that BPA should provide this assessment as a "checkpoint" to assure public power that the ASCM will be a fair and verifiable method to calculate ASCs for exchanging utilities. (*Id.*)

BPA acknowledges it is possible that the ASCM may need to be adjusted to address issues identified during its implementation. That is why the proposed ASCM includes provisions for revisiting the Methodology. It is not clear however, that it is appropriate to establish a date certain to address such issues. Several years of implementing the new ASCM may have to pass before interested parties can fully understand which aspects of the ASCM 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 ASCM contains a mechanism that allows BPA or regional parties to request a consultation process to revise the Methodology. Specifically, Section V of the proposed ASCM 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. This provision is 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 ASCM.

Furthermore, the adoption of Snohomish's suggestion could inhibit BPA and the parties from addressing serious problems in the ASCM 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 ASCM 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.

PPC argues that in light of the significant changes and uncertainties introduced by the new ASCM, a provision that automatically triggers a consultation process is reasonable. (PPC, AS20009 at 3.) However, the proposed 75 percent threshold is too high, and should be reduced to 50 percent. (*Id.*) First, it should be clarified that reaching the 75 percent threshold does not automatically begin a new consultation proceeding. The Administrator still retains the discretion whether to begin a consultation proceeding after receiving such a request, although the Administrator would provide an explanation of why a new consultation proceeding was not necessary. As a practical matter, however, BPA's customer classes effectively convey their concerns regarding BPA's programs, including the REP, even in the absence of a 75 percent requirement. Although the ASCM establishes a 75 percent threshold, the Administrator retains discretion to begin a consultation proceeding even if fewer requests were made.

Decision

The ASCM will not commit to reviewing and assessing the new ASCM in 2013. The new ASCM 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 ASCM.

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 file initial comments on this issue.

BPA's Position

BPA proposed 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

BPA proposed 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.

PSE notes that page 9 of the draft ASCM includes the following: "3. If the escalators determined in the ASCM are no longer available, BPA will escalate those costs using the forecast of the GDP Price Deflator, or will designate an equivalent source of escalators." PSE suggests this sentence should be revised to read as follows: "3. If the escalators determined in the ASCM are no longer available, BPA will designate a replacement source of escalators that as near may be replicates the results produced by the prior escalator and, if such a replacement source is not available, the replacement escalator will be the forecast of the GDP Price Deflator."

BPA agrees with PSE that the replacement escalators should replicate the results produced by the prior escalator as closely as possible and that PSE's proposed language is generally appropriate.

Decision

The ASCM will use Global Insight's (or its successor'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. 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. BPA will change the ASCM language to read: "3. If the escalators determined in the ASCM are no longer available, BPA will designate a replacement source of escalators that, as near as possible, replicates the results produced by the prior escalator and, if such a replacement source is not available, the replacement escalator will be the forecast of the GDP Price Deflator."

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 IOUs state that FERC Form 1 data for a given year reflects expenses incurred throughout that entire year and reflects investments as of the end of that year. (IOU, ASC0004, at 7.) Therefore, the IOUs state, 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 FRN 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. Escalating Base Period costs to the midpoint of the 2-year Exchange Period seemed likely to help BPA 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. Escalating the costs included in ASC to the end of each year while escalating the costs BPA includes in its rates to the middle of each year would not be consistent or equitable treatment. The costs included in ASC would always have an extra 6-months escalation when compared to the costs included in BPA's rates. 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. In their comments on the Draft ROD, the IOUs agreed with BPA's approach.

Decision

The ASCM will escalate the 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 using BPA's forecast of PF rates and prices for the various power products that BPA provides.

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 that major resource and transmission investments and contracts should be allowed to trigger an ASC change within a rate period. (IOU, ASC0004, at 6.) The IOUs state that long-term contracts may substitute for generation and transmission resources. (*Id.)* The IOUs argue that as such, long-term contracts are comparable to major resources and should be allocated to either production or transmission. (*Id*. at 7.) The IOUs state that 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.*) The IOUs argue that 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 proposes to determine the Exchange Period ASCs during a public review process prior to the start of the Exchange Period, which includes 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
6. Hydro relicensing costs and fees

(IOU, ASC0004, at 6.) 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 Section 4.2.8, Transmission Cost Projection, BPA explains the method it will use for inclusion of future transmission resource additions.

In their comments on the Draft ASCM ROD, the IOUs note that BPA does not appear to allow for stand alone changes in gas contracts or other O&M costs as a trigger for a new ASC but rather would rely on the application of cost escalators for these types of O&M accounts related to existing production resources/facilities. (IOU, AS20007 at 4-5; PSE, AS20009 at 4-5.) They note that PSE is facing increases in the fuel costs of its other production facilities due to the loss of long-term fixed-price gas contracts, as well as incurring overall cost increases in gas costs due to the market increases. (*Id.*) That is, the Utility's production costs will be increasing due to the expiration of four long-term gas for power contracts that were below current average market prices. (*Id.*) If not includable as new resource costs, the full impact on the ASC will not be seen until rates are set with 2009 FERC Form 1 data at the earliest. (*Id.*) BPA's escalation factors consider overall cost increases but cannot begin to consider the effect of long-term contracts expiring. (*Id.*) Accordingly, the allowed new resource cost changes should include: (1) terminated/expiring long-term contracts (such as the expiring gas for power contracts, but could also be below-market power purchase agreements (PPAs) and (2) new gas transportation contracts/investments. (*Id.*) Current cost estimates suggest that costs included in Account 547 would increase in 2008 by almost 40% over 2006 base year costs. (*Id.*) BPA's forecast model includes escalators for Account 547 of 3%, 11.3% and 4.7% in 2007, 2008 and 2009 respectively. (*Id.*) These levels of cost escalators are not sufficient for this cost item. (*Id.*) BPA should include this clarification in its Decision and should specifically include: (1) terminated/expiring long-term contracts (such as the expiring gas for power contracts, but could also be below-market PPAs and (2) new gas transportation contracts/investments. (*Id.*)

BPA's Draft ROD allowed new long-term generating contracts to be included in ASC, subject to meeting the materiality threshold. PPAs are considered a long-term generating contract for ASC purposes and therefore allowed in ASC, subject to meeting the materiality threshold. However, replacements or changes to existing gas contracts are not considered to be a major resource addition. BPA views changes to these types of contracts as a type of true-up. The issue of allowing true-ups to a Utility's forecast ASC was discussed extensively during the consultation process, and was rejected for the following reasons. First, allowing true-ups would increase the complexity and administrative burden of the REP. Second, ASCs are established prior to BPA setting its power rates. This is necessary because ASCs are a major determinant of whether the section 7(b)(2) rate test triggers and the resulting Utility PF Exchange rates used to calculate REP benefits. If BPA were to allow true-ups to ASC, there would be a disconnection between the ASCs used to establish rates and the ASCs used to calculate actual benefits. Third, BPA is establishing ASCs for 2 years only, so actual costs for calculating ASCs would be updated every 2 years. During the discussions with stakeholders, there was general agreement that establishing ASCs for 2-year periods reduced the need for a true-up. Finally, BPA is concerned that the terms of any future replacement fuel contracts would not be known during the ASC review period when ASCs are established, so any forecast of replacement costs would be highly speculative.

<u>Decision</u>

The ASCM will include the costs of resource investments (production or generating), transmission investments, long-term generating or transmission contracts, pollution control and environmental compliance investments, plant rehabilitation investments, and hydro relicensing costs and fees 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. Changes or replacements to existing fuel contracts will not be allowed. The costs of new replacement gas contracts actually incurred will be included in future Base Period costs.

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. A 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 was 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 be included in Section IV of the ASCM.

1. At the time the Utility submits its Appendix 1 filing, the exchanging Utility will provide its forecast of major new resource additions 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 new resource costs to be included in the Utility's Exchange Period ASC will be reviewed and determined during the Review Period.

3. All major new resources included in an ASC calculation prior to the start of the Exchange Period will be projected forward to the mid-point of the Exchange Period.

4. For each major new resource addition forecast to be available to meet regional retail load during the Exchange Period, BPA will calculate the difference 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.

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

6. Steps 1 through 5 above will also be used in a similar manner for resources that are sold, transferred or retired.

Decision

The ASCM 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 contracts, pollution control and environmental compliance investments relating to generating resources or contracts, plant rehabilitation investments, and hydro relicensing cost and fees.

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 IOUs also suggest that resource additions should accumulate from the Base Period and be included in ASC when the accumulated changes in aggregate exceed the materiality threshold. (IOU, AS20007 at 6; PSE, AS20009 at 6.)

The Idaho PUC encourages 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. Parties did not favor Alternative 2 because smaller utilities might never reach the dollar threshold, even though a change in Contract System Costs lower than the threshold could result in a substantial change in small utilities' ASCs. This left Alternative 3, a percentage change in ASC, which parties stated would be the fairest approach. There was general agreement that a 2.5 percent change in ASC was a reasonable threshold for triggering a change in a Utility's ASC.

In their comments on the Draft ASCM ROD, the IOUs state it is not evident whether BPA's proposal allows for cumulative changes made during the rate case to trigger the materiality threshold. (IOU, AS20007 at 6; PSE, AS20009 at 6.) The IOUs propose that BPA adopt an ASCM that allows for resource additions or deletions to accumulate during the rate period. (*Id.*) A Utility's ASC should be updated when the accumulated changes from the Base Period in aggregate exceed the materiality threshold. (*Id.*) BPA should include both Production and Transmission additions and deletions when determining whether the materiality threshold has been triggered. (*Id.*)

BPA agrees with the principle of allowing for cumulative changes to trigger the materiality threshold. During the expedited ASC review process, it became apparent that many renewable resource purchases, by themselves, would fail to meet the materiality threshold. State renewable resource mandates require a certain percentage of utilities' new resources be renewables. Therefore, BPA believes it would not be appropriate to exclude the costs of new renewable resources from ASC simply because they failed to meet the materiality threshold. However, BPA is equally concerned about the administrative cost and burden of estimating multiple ASCs for a rate period and having to constantly change ASCs for billing purposes as multiple new resources come on-line.

To address these concerns, BPA will revise its treatment for including new resources in the calculation of exchanging utilities' ASCs. BPA will allow utilities to present stacks of new individual resources that, when the resource costs are combined, meet the materiality threshold. However, BPA will only allow the costs of individual resources into a resource stack that change a Utility's Base Period ASC by 0.5 percent or more. This minimum threshold will ease the administrative cost and burden of verifying the estimates of the resource costs included in these stacks. The new ASC will go into effect only when all resources in the stack have come on-line.

Decision

The ASCM will adopt a materiality threshold of a 2.5 percent change in a Utility's Base Period ASC for determining when a change in ASC will be made for resource additions or reductions. BPA will allow utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more. This treatment allows exchanging utilities to include resources required under state renewable resource mandates while lessening the administrative cost and burden of verifying the resource cost estimates during the ASC review period.

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; IOU, AS20007 at 6.) Long-term contracts may substitute for generation and transmission resources. (*Id.*)

BPA's Position

The Draft ASCM ROD proposed 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 would 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 some limitations to this approach soon became apparent. Many of the proposed transmission investments were too small to be material, and much of the supporting documentation was 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 included in the Draft ASCM ROD accomplished this by including a forecast of additional investment costs needed to serve the Utility's post-Base Period load growth. BPA argued that this method avoided the need to determine the portion of the costs of new transmission investments incurred for out of region sales and avoided the difficulty of estimating the revenues from wheeling power for other utilities. In addition, the costs of new transmission investments actually incurred would be included in future Base Period costs.

In their comments on the Draft ASCM ROD, the IOUs state that BPA's draft decision and rationale have three flaws. (IOU, AS20007 at 6; PSE, AS20009 at 7.) First, while some transmission investments may be small, some will be very large – PacifiCorp's Energy Gateway Project, announced in 2007, with the first phase to be completed in 2010, is estimated to cost $4 billion. (*Id*.) Second, generating and transmission resources receive the same rigorous review and have the same level of supporting documentation. (*Id*.) Third, the size of transmission investments is not necessarily related to load growth. (*Id*.) BPA should use the methodology laid out in Section 4.2.5 of the Draft Record of Decision for both new production-related and transmission additions and reductions. (*Id*.) A Utility may decide to not include new transmission resources in the list of resources submitted to BPA. (*Id*.) For these utilities, BPA will project the Utility's costs of transmission investments needed to meet load growth using the escalated average cost of transmission. (*Id*.)

Similar to new large generating plants, BPA agrees that large transmission investments may be made ahead of need to minimize long-term cost. Transmission investments may also be made to maintain system reliability, or to meet safety or regulatory requirements. For these reasons, BPA will allow new transmission investments in ASC subject to the same requirements as new generating investments. However, BPA remains concerned that allowing large new transmission investments without estimating the associated increase in off-setting wheeling revenues will overstate a Utility's ASC.

BPA will calculate new transmission wheeling revenues associated with new transmission investment by the following formula:

$$NTWR = WR_{(\text{before additions})} * [(NTP_{(\text{before additions})} + NTA) / NTP_{(\text{before additions})}]$$

Where:

- $NTWR$ = New transmission wheeling revenues
- $WR_{(\text{before additions})}$ = wheeling revenues (before additions)
- $NTP_{(\text{before additions})}$ = (Net Transmission Plant (before additions)
- NTA = new transmission additions

Decision

The ASCM will allow the costs of major new transmission investments in ASC under the same conditions as new generating investments. Additional wheeling revenues will be estimated using the methodology described above.

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

The ASCM 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 Production-Transmission-Distribution (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

The ASCM 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

Snohomish suggests BPA should commit to developing acceptable protections for confidential information in a forum outside the ASCM. (Snohomish, AS20006 at 1-2.) The IOUs state that BPA should develop special procedural rules in advance of the Final ROD so they can be evaluated and included in the overall review of this process and the Final ROD. (IOU, AS20007 at 7; PSE, AS20009 at 7-8.)

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.

In its comments on the Draft ASCM ROD, Snohomish notes the Draft ROD concluded that failure to provide needed information may result in the exclusion of the related costs, but BPA reduced the impact of this penalty by committing to use market purchases to meet load growth in this situation. (Snohomish, AS20006 at 1-2.) Snohomish states this creates an opportunity for mischief, as the wholesale market now serves as a resource cost floor. (*Id.*) Snohomish states that if a Utility is able to secure a below-market resource, it can claim "confidentiality" and include the higher market rate in the ASC calculation. (*Id.*) Snohomish suggests BPA close this loophole by deleting the final two sentences of its decision and committing to develop acceptable protections for confidential information in a forum outside development of the ASCM. (*Id.*)

Under BPA's proposal, the costs of new resource additions will be provided by the exchanging utilities as part of their ASC filings with BPA. The resource addition costs will then be subject to the same public review as all of the utilities' costs. If a Utility has access to below-market resources and fails to provide those resources in its filing, the public review process will allow parties the opportunity to voice their concerns. In any event, the current Exchange Period is limited to a 2-year maximum, so the actual costs of any below-market resources can be excluded from ASC for a relatively short period of time. Also, the below-market costs will show up in the Utility's future ASC filing.

BPA agrees with Snohomish's suggestion that confidentiality provisions should be developed in a process that is separate from the ASCM consultation process. This consultation proceeding has addressed many substantive provisions of the ASCM but less time has been spent discussing specific confidentiality concerns. These concerns are best addressed in a forum where BPA and its customers can have an open and focused dialogue on particular confidentiality issues. As such, BPA commits to work with customers to develop confidentiality provisions outside of this consultation process.

The IOUs note the Draft ROD, which states "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." (IOU, AS20007 at 7; PSE, AS20009 at 7-8.) The IOUs state that, in fact, new resource costs may be incurred to meet existing or current load (i.e., the replacement costs of expiring long-term gas contracts and/or purchase power contracts). (*Id.*) Also, the IOUs state this language is of great concern in light of BPA's apparent plan to not allow for a true-up mechanism. (*Id.*) Taken together, the inability to work with confidential data and the likely understating of the ASC impacts of new resource costs when replaced by the BPA proxy of "the price of electricity in the wholesale market" will result in postponing the full ASC impacts of new resource costs that would have otherwise triggered a change in ASC. (*Id.*)

As stated in Section 4.2.4 above, the issue of allowing true-ups to a Utility's forecast ASC was discussed extensively during the consultation process and was rejected for the following reasons. First, allowing true-ups would increase the complexity and administrative burden of the REP. Second, ASCs are established prior to BPA setting its power rates. This is necessary because ASCs are a major determinant of whether the section 7(b)(2) rate test triggers and the resulting Utility PF Exchange rates used to calculate REP benefits. If BPA were to allow true-ups to ASC, there would be a disconnection between the ASCs used to establish rates and the ASCs used to calculate actual benefits. Third, BPA is establishing ASCs for 2 years only, so actual costs for calculating ASCs would be updated every 2 years. During the discussions with stakeholders, there was general agreement that establishing ASCs for 2-year periods reduced the need for a true-up.

The IOUs state that processes are in place at the state jurisdictional level to address confidentiality requirements. (IOU, AS20007 at 7; PSE, AS20009 at 7-8.) The process in place for use in proceedings before the WUTC is described in RCW 80.04.095, WAC 480-07-160, and WAC 480-07-420. (*Id.*) These procedures could serve as a starting point for BPA to use in formulating its special procedural rules for addressing the confidentiality of data provided in conjunction with the ASC including new resource costs and new large single load determinations. (*Id.*) BPA should provide these special procedural rules to the participants of this process in advance of the Final Record of Decision so that they may be evaluated and included in the overall review of this process and the record of decision. (*Id.*)

As noted above, BPA intends to develop special rules to protect the confidentiality of sensitive information provided in the ASC review process in a separate forum. The recommendations noted by the IOUs are a useful starting point, and BPA will consider these references as it prepares the procedures for the ASC Review Process. BPA also agrees with the IOUs' suggestion that parties be allowed to comment on the special rules BPA develops for the Review Process in the fall. Such a process will allow all customers to express opinions on how best to protect sensitive information while still providing meaningful access to ASC data for participants in the Review Process.

BPA, however, declines to undertake this process prior to the completion of the final ASCM and this Record of Decision. First, BPA has not had sufficient time to consider what confidentiality provisions would be necessary or relevant for the Review Process. The IOUs have provided a few examples of such provisions from state law. BPA will need time to evaluate whether these provisions are compatible with the ASC Review Process and BPA's own disclosure requirements under federal law. BPA will also have to consider the confidentiality procedures that were previously used in the ASC Review Processes under the 1981 and 1984 ASCMs. Finally, BPA also intends to review the confidentiality procedures used in its section 7(i) rate cases. All of these reviews will take time, and cannot be completed prior to the publication of this Record of Decision.

Second, as noted earlier, BPA intends to provide parties with an opportunity to comment on the confidentiality procedures. Even if the special rules for protecting confidential information could have been developed in the limited time available, BPA does not believe there would have been sufficient time to allow the parties a meaningful opportunity to comment on the procedures before the publication of this Final Record of Decision.

Finally, BPA does not believe that it is necessary at this juncture to rush to develop confidentiality provisions as part of the ASCM consultation process. In both the 1981 ASCM consultation process and the 1984 ASCM consultation process, BPA did not develop specific confidentiality provisions prior to the submission of the Methodologies to FERC. Rather, confidentiality procedures were developed as part of BPA's Review Processes. BPA sees no reason to depart from this practice in the present case. All parties will still have an opportunity to comment on the procedures BPA develops, so adopting confidentiality provisions outside of the ASCM will not be prejudicial.

PSE notes that the draft ASCM includes the following: "1. After a Utility files electronically an Appendix 1, BPA shall provide access to these filings to each of BPA's Regional Power Sales Customers or its designee." (PSE, AS20009 at 8.) PSE argues this sentence should be revised to read as follows: "1. After a Utility files electronically an Appendix 1, BPA shall provide access, contingent on proper safeguards to prevent unauthorized use or disclosure, to these filings to each of BPA's Regional Power Sales Customers or its designee." (*Id.*)

Similarly, PSE notes that the draft ASCM includes the following: "Day 8: BPA will provide electronic access for all Regional Power Sales Customers to the Utilities' Appendix 1 filings within one week after filing." (PSE, AS20009 at 8.) PSE argues this sentence should be revised to read as follows: "Day 8: BPA will provide electronic access, contingent on proper safeguards to prevent unauthorized use or disclosure, for all Regional Power Sales Customers to the Utilities' Appendix 1 filings within one week after filing." (*Id.*)

BPA agrees with PSE's suggestions with some minor modifications. BPA proposes to change the language in section II.E.1 to the following:

> After a Utility files electronically an Appendix 1, BPA shall post the filings and any non-confidential documentation on its electronic website. **Access to such information shall be subject to any confidentiality rules or requirements established by BPA.**

Similarly, BPA proposes to modify the language in Section III.E.2. as follows:

> Day 8: BPA will provide electronic access for all Regional Power Sales Customers to the Utilities' Appendix 1 filings within one week after filing. **Access to such information shall be subject to any confidentiality rules or requirements established by BPA.**

These revisions make clear that Regional Power Sales Customers or their designees will only receive the information from the Appendix 1 if they agree to abide by BPA's special rules on confidentiality. PSE's proposed revision was too restrictive because it imposed prohibitions on *BPA* from disclosing the information absent the development of "proper safeguards to prevent the unauthorized use or disclosure" of the information. BPA believes its revision meets the IOUs' need for confidentiality without unduly restricting the ability of BPA to develop special rules for the Review Process.

Decision

The ASCM 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. BPA will provide *parties with an opportunity to comment on the rules prior to their implementation in the 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 file initial comments on this issue. PSE suggests BPA adopt a materiality threshold for changes in Utility service territory. (PSE, AS20009 at 9.)

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 stated 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 forecasts to acquire a new service territory or lose a portion of its service territory, the Utility will submit two ASC filings:
>
> 2. A base year filing that does not reflect the acquisition or loss of service territory, and
>
> 3. A second filing that incorporates:
>
>   a. The forecast of the increase or reduction in Contract System Load associated with the acquisition or reduction in service territory.

b. The forecast of the increase or reduction in Contract System Costs associated with the acquisition or relinquishment of the service territory.

c. In addition to including the forecast of capital and operating cost increases or reductions associated with the change in service territory, the Utility must also forecast 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 actual change in the new service territory could differ from the forecast date used to determine the ASC during the Review 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 used for changing ASCs due to major resource additions or retirements.

PSE suggests BPA should adopt a materiality threshold for changes in Utility service territory that will result in a change to a Utility's ASC when the sale or purchase is finalized during the rate period (Exchange Period). (PSE, AS20009 at 9.) For example, minor annexations or changes in the serving Utility for a small amount of load should not necessarily trigger a between-rate period adjustment of ASC. (*Id*.)

BPA agrees that adopting a materiality threshold for changing ASC due to changes in a Utility's service territory is appropriate. It is consistent with BPA's goal of limiting the administrative cost of the REP, and with the treatment of new resource additions.

Decision

The ASCM 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. The change in ASC must meet the same materiality threshold as the change in ASC resulting from adding major new resources, that is, a 2.5 percent or greater change up or down in Base Period ASC.

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 that 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 1-2.) The IOUs argue that in the absence of a true-up, 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 use real dollars to allow for effects of inflation. (*Id. at 5.)*

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.) WUTC argues that five-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, WUTC would support an approach that would true 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 five-year average of short-term (less than one year) energy sales and energy purchases in the Appendix 1 to determine the quantity of short-term sales and purchases. In the event the five-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. WUTC contends that a single-year's FERC Form 1 will not fairly represent actual costs in subsequent years. (WUTC, ASC0005 at 25-26.) 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. (*Id.)* The IOUs contend that use of the FERC Form 1 data could create the potential for anomalous power costs in ASCs. (IOU, ASC0004, at 1-2.) 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 and 555) on a rolling five-year basis. (*Id.)*

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 depend on 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.

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 and 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 not only the costs, but also normalizing the generation operations. As described above, this would require relatively complex analysis and modeling.

Decision

The ASCM 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 as the starting values for the forecast. The Utilities will then be allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue to be included in the Rate Period ASCs.

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 at which they sell surplus power can be different. (*Id.*) This difference will affect future ASCs. 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 FRN 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 at which 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 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 will use to forecast the short-term purchase power price and short-term sales for resale price for each Utility is as follows:

1. The Utility's 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 (Base Period and prior two years).

2. The mid-point between the Utility's average short-term purchased power price and short-term sales for resale price will be calculated for each of the years in step one above.

3. The percentage spread around the Utility's mid-point between the average short-term purchase power price and short-term sales for resale price will be calculated for each of the years in step one.

4. A weighted average spread for the Utility's most recent three years of actual data (Base Period and prior two years) will then be calculated. The following weighting scale will be used:

a. 3 times Base Period spread
b. 2 times (Base Period year minus 1) spread
c. 1 times (Base Period year minus 2) spread

This weighted average spread will be used in the forecast.

5. The Base Period mid-point price calculated in 2 will be escalated at the same rate as BPA's market price forecast.

6. The weighted average spread calculated in 4 will then be applied to the forecasted mid-point calculated in 5 to determine the purchased power and sales for resale price, to value purchased power expenses and sales for resale revenue to be included in the Rate Period ASCs.

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>

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

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

2) <u>Mid – Point Calculation</u>

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

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

If ST-PP > ST-SFR

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

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

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) **Forecasted Mid-Point**

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

6) **Forecasted Short Term Purchased Power and Sales For Resale Prices**

If ST-PP > ST-SFR

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

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

Decision

The ASCM will use the method described above to determine separate Utility 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* ROD Section 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 forecast 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 power provided by 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 forecast short-term purchased power price.

3. In the event that the power provided by a new resource exceeds the Utility's forecast load growth, the excess will be sold as surplus power into the market and priced at the Utility's forecast sales for resale price as determined in the ASCM section IV. B.

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

The ASCM 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.

4.2.15 Environmental Attributes, Renewable Energy Certificates and Carbon Credits

Issue

Whether BPA should refrain from making final decisions on the treatment of Environmental Attributes, Renewable Energy Certificates, and carbon credits..

Parties' Positions

The OPUC suggests that BPA refrain from making final decisions on the treatment of carbon credits until there is further clarity regarding regulation of carbon emissions and the level of credits that BPA may receive in the future. (OPUC, AS20011 at 1.) The IOUs state the value of Tier 1 and Tier 2 Environmental Attributes should not be allocated solely to PF Preference rate customers but rather should be equitably allocated among all BPA Customers that pay the costs of resources from which such Environmental Attributes are derived. (IOU, AS20007 at 17-18.) The IOUs request the opportunity to fully review the impact of this language and the ability to provide formal comments. (*Id.*)

BPA's Position

BPA previously took no position on the treatment of Renewable Energy Certificates, carbon credits or any other Environmental Attributes for purposes of the ASCM.

Evaluation of Positions

The OPUC identifies an issue regarding the REP treatment of any BPA renewable energy or carbon credits for which BPA is "awarded" in connection with BPA's marketing role of hydroelectric projects, acquisition of renewable power, or other means of carrying out BPA's obligations to provide service to its statutory customers. (OPUC, AS20011 at 1.) The OPUC understands that BPA may be contemplating transferring ownership of such renewable energy or carbon credits to Tier 1 customers, at no charge. (*Id.*) Under the presumption that renewable energy credits awarded to BPA are *de minimis*, the OPUC takes no position at this time regarding BPA's proposal with respect to renewable energy credits. (*Id.*) With respect to carbon credits, however, the OPUC has concerns about BPA's proposal to transfer such credits to Tier 1 customers at no charge. (*Id.*) The OPUC states that the future of carbon regulation is murky and it is unclear how carbon-related issues will be treated by Congress and other administrative agencies in the future. (*Id.*) The OPUC also notes that it is unclear what level of carbon credits might be awarded to BPA, both in terms of the quantity and monetary value. (*Id.*) In light of this uncertainty, the OPUC requests that BPA refrain from making any final decisions as to how carbon credits will be treated until there is further clarity regarding regulation of carbon emissions and the level of credits that BPA may receive in the future. (*Id.*)

The IOUs note that a policy decision seems to have been implemented through the Regional Dialogue contract review process with no formal review and opportunity to provide comments. (IOU, AS20007 at 17-18; PSE, AS20009 at 20.) The IOUs state that the value of Tier 1 and Tier 2 Environmental Attributes should not be allocated solely to PF Preference rate customers but rather should be equitably allocated among all BPA Customers that pay the costs of resources from which such Environmental Attributes are derived. (*Id*.) The IOUs request the opportunity to fully review the impact of this language and the ability to provide formal comments. (*Id*.)

BPA recognizes that the OPUC and IOUs have concerns over BPA's treatment of Renewable Energy Certificates and carbon credits associated with the Federal system. However, BPA cannot address those concerns in this Record of Decision because such a decision would be both premature and outside the scope of this consultation. First, the full value of Environmental Attributes associated with the Federal system, including Renewable Energy Certificates and carbon credits in particular, is unknown at this time. These markets are rapidly evolving and to much extent remain ill-liquid.. There is, therefore, insufficient information currently available upon which BPA can make a final decision regarding the REP treatment of Renewable Energy Certificates, carbon credits or Environmental Attributes in general at this time.

Second, even if BPA were prepared to make a definitive statement on the treatment of Environmental Attributes, Renewable Energy Certificates or carbon credits, BPA would not make that decision in this Record of Decision. The purpose of the consultation is to establish the ASCM that will be used to calculate a Utility's average system cost pursuant to section 5(c) of the Northwest Power Act. *See* 16 U.S.C. § 839c(c)(5). Consequently, the issues that must be addressed in this Record of Decision are limited to matters that directly relate to the determination of ASCs under the proposed ASCM. The concerns raised by the OPUC and the IOUs as to how BPA will use the Environmental Attributes, Renewable Energy Certificates or carbon credits of the Federal system go beyond the narrow set of issues BPA set out to address through this consultation. BPA specifically noted in its FRN the purpose of this proceeding:

> [BPA] proposes a revised methodology for determining the average system cost (ASC) of resources for regional electric utilities that participate in the . . . [REP] authorized by section 5(c) of the [Northwest Power Act]. . . . This consultation proceeding is intended to facilitate the compilation of a full record upon which the Administrator will base his decision for a final ASCM.

73 Fed. Reg. 7270 (Feb. 7, 2008).

Using this proceeding to now address the treatment of Renewable Energy Certificates, carbon credits and other Environmental Attributes of the Federal system would inappropriately expand the stated scope of this consultation into topic matters that have not been properly identified in BPA's notice. Such an expansion would endanger the viability of the ASCM decisions being made in this Record of Decision and be fundamentally unfair to other interested parties who may want to submit comments and express their views on BPA's treatment of Renewable Energy Certificates, carbon credits or other

Environmental Attributes. Therefore, BPA cannot make any final decisions in this Record of Decision regarding any Environmental Attributes.

BPA, however, recognizes the concerns that the IOUs and OPUC express in their comments. If implementation issues associated with Renewable Energy Certificates, carbon credits or other Environmental Attributes and the ASCM become more apparent and real in the future, BPA will consider all appropriate options to address such issues. Such options may include adjusting BPA's design of the PF Exchange rate or, if appropriate, commencing a new limited consultation proceeding to review the ASCM.

Decision

The ASCM cannot make any decisions in this Record of Decision on the treatment of Environmental Attributes, Renewable Energy Certificates or carbon credits because such decisions would be premature and outside of the scope of the ASC consultation. However, if implementation issues associated with Environmental Attributes, Renewable Energy Certificates or carbon credits and the ASCM become more apparent and real in the future, BPA will consider all appropriate options to address such issues. Such options may include adjusting BPA's design of the PF Exchange rate or, if appropriate, commencing a new limited consultation proceeding to review the ASCM

4.2.16 Length of Exchange Period

Issue

Whether BPA should limit the length of the Exchange Period to no more than two years.

Parties' Positions

WUTC and PSE recommend that BPA include in either the ASCM or the RPSAs a requirement that ASCs will be reset using the annually filed FERC Form 1 data no less than every two years, regardless of the length of the rate period. (WUTC, AS20002 at 10-11; PSE, AS20009 at 20.)

BPA's Position

In the proposed ASCM, BPA proposed to set the Exchange Periods equal to the term of BPA's wholesale power rate periods.

Evaluation of Positions

WUTC states that it can support "freezing" the ASC for relatively short duration rate periods, subject to the limitations proposed by BPA. (WUTC, AS20002 at 10-11.) However, if BPA rate periods become longer, BPA-determined ASCs may increasingly depart from actual Utility costs for reasons other than the two allowed, i.e., fuel costs and net power purchase costs. (*Id.*) Actual costs could depart in either direction from the established ASC. (*Id.*) Consequently, to ensure that ASCs reflect actual costs as accurately as possible, the WUTC recommends that BPA include in either the ASCM or the RPSAs a requirement that ASCs will be reset using the annually filed FERC Form 1 data no less than every two years, regardless of the length of the rate period. (*Id.*) PSE similarly argues that in the absence of true-up provisions, subsequent Exchange Periods in excess of two years will arbitrarily and capriciously result in failure to reflect appropriate ASCs during the Exchange Period because of the deviation of actual costs during that period from the projected costs developed under the ASCM. (PSE, AS20009 at 20.) Therefore, in the absence of such true-up provisions, the ASCM and individual Residential Purchase and Sale Agreements should each specify that BPA's wholesale power rate periods shall not exceed two years. (*Id.*)

BPA agrees in principle with the observations made by WUTC and PSE. It is true that longer Exchange Periods are more likely to result in disconnections between ASCs developed from historical base year data and actual ASC costs. However, BPA is not prepared, at this point, to commit to recalculating ASCs every two years.

BPA is concerned that if it agrees to set a "hard" limit for recalculating the ASC every two years, it could sever the close interplay between the ASC determinations and BPA's wholesale power rate cases, which is one of the key features of the new ASCM. Under the ASCM, ASCs are determined prior to the commencement of BPA's power rate case and are set for the duration of the rate period. Once the rate period begins, the ASCs can only change to reflect the costs of new resources that previously met a materiality test in the ASC review process. The "fixed" nature of the ASCs is designed to make the operation of the REP more predictable and certain for both the recipients of the exchange payments and to the customers that pay REP costs in rates. By developing ASCs prior to the rate case, BPA does not need to "forecast" ASCs for the rate period because they are already set. These fixed ASCs allow BPA to estimate the cost of the REP in ratemaking with more precision than before. (Actual exchange payments are still based on the exchangeable loads of the utilities, which will continue to be submitted monthly). Without this feature, BPA would have to continue its current practice of forecasting ASCs to calculate the REP costs recovered in rates and then use cost recovery mechanisms (CRACs) and other within rate period adjustments to capture the variable costs of the REP. Limiting this variability through the establishment of ASCs prior to the wholesale power rate cases is a key feature of the new ASCM.

Thus, BPA acknowledges that a longer than two-year rate period could create data problems with the development of the ASCs because the base year data, which itself is historical data, may become exceedingly stale. Although BPA does not anticipate returning to rate periods that exceed two years, WUTC's and PSE's concerns are valid. To address these concerns, BPA will commit to work with the exchanging utilities if BPA's wholesale power rate period extends beyond two years. In that event, BPA commits to consider any and all options to ensure the viability and accuracy of the ASCs and avoid the stale data problems noted by WUTC and PSE.

Decision

In the event the ASCM will set power rates for a rate period exceeding two years, The ASCM commits to work with exchanging utilities to consider any and all options to ensure the viability and accuracy of the ASCs and avoid stale data problems.

4.3 Functionalization Codes

Introduction

The 2008 ASCM 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 will 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 analyses are subject to BPA review and approval. The Utility-prepared direct analysis shall categorize costs to Production, Transmission and Distribution/Other functions as provided in the ASCM.

A direct analysis may be performed only if Table 1 indicates that a Utility may perform a direct analysis on the Account. The only exception to this requirement is for conservation-related costs. Because the FERC Form 1 does not contain a specific set of accounts for conservation-related costs, Utilities record those costs in a variety of FERC accounts. Utilities will be able to identify and functionalize to Production any conservation-related costs, irrespective of the account in which they are recorded. As explained in greater detail in sections 4.3.10, and 4.3.11, if a Utility records conservation costs in an account that is normally functionalized to Distribution/Other, the Utility will identify and document the conservation-related costs included in the account, and the balance of the costs will be functionalized to Distribution/Other. The presence of conservation-related costs in an account does not give the Utility permission to perform a direct analysis on the entire 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 that demonstrate such cost assignment is appropriate. The Utility must submit with its ASC filing any and all work papers, documents, and other materials that demonstrate 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 the exception of items included in Schedule 3B, *Other Included Items*, where the Account will be functionalized to Production as appropriate.

Functionalization of certain Accounts may be based on a 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 consultation process. Functionalization determinations not challenged 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.) Portland General Electric (PGE) notes that, for example, Account 114 for Puget Sound Energy (PSE) for 2006 includes costs relating to a combustion turbine; as such, these costs are appropriately included in ASC and functionalized as PROD. (*Id.)* PGE states that the remainder of the plant balance relates to Transmission and Distribution. (*Id.)* PGE notes that the template does appears to allow DIRECT for the related expense (*see* Amortization of Plant Acquisition Adjustments (Electric) on tab Sch 3 - Expenses). (*Id.)*

BPA's Position

The proposed ASCM requires functionalization of Account 114, Acquisition Adjustments, by direct analysis.

Evaluation of Positions

One of the 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 will 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 in which 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 factors that led to passage of the Federal Power Act in 1935.[6]

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 numerous FERC, state commission, and state and Federal court rulings concerning acquisition adjustments: (1) should the costs be included in

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

rate base, and (2) should the amortization of these amounts be considered an operating cost? Treatments 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, whereas 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. (IOU, ASC0004 at 4-5.) The IOUs suggest utilities should be allowed to perform a direct analysis on Account 114. (*Id.*) BPA agrees with the IOUs on this issue.

Decision

The ASCM will require Utilities to 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 claim 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 suggest that BPA exclude this account completely from ASC. (*Id.)*

BPA's Position

BPA initially proposed that Investment in Associated Companies, FERC Account 123, would be functionalized using the PTD ratio. After 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 proposed 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/Other.

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/Other. BPA changed its position on this issue as a result of the discussion and analysis in the ASCM consultation process when representatives of IOUs established 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 contend that allowing Investments in Associated Companies in ASC will cause costs unrelated to an IOU's resources into ASC. (PPC/NRU, ASC0006 at 13.) PPC/NRU claim 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.)* PPC/NRU claim that 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 that 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 the 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. The chance that improper cost *may potentially* be included in ASC as a result of including Account 123 in ASC is not a valid reason to exclude Account 123 from ASC. It simply means that BPA and other participants in the ASC review process should examine closely the components of Account 123 to ensure that only allowable costs are included in ASC. In response to the concerns of PPC/NRU and other participants in the ASC consultation process, BPA revised its position to require that Utilities 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/Other and thus not included in Contract System Cost.

Decision

Exchanging utilities will be required 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/Other.

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.) PPC/NRU state that BPA's initial proposal that assets accumulated in "Derivative Instruments" Accounts 175-176 should be included in rate base and functionalized to Production for the purpose of ASC 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, PPC/NRU recommend that assets should be subject to direct analysis, because it is not clear that these are associated in every case with generation costs. (*Id.)* PPC/NRU state that 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' ASCs. Further, once these transactions were realized or are marked to market, the gain or loss on the derivative would be recognized in current earnings in FERC Account 555. Expenses in Account 555, Purchased Power, are included in ASC.

Decision

The ASCM will functionalize Accounts 175, 176, 244, and 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

The proposed ASCM 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 its conservation program costs 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 Section 4.6*, Conservation and Oregon Public Purpose Charge.*

Decision

The ASCM 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.) The IOUs claim that 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 will include amounts paid to the Federal government or to a state or 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.[7] It also states that if a franchise, consent, water power license or certificate is acquired by assignment, the charge to this account shall not exceed the amount paid 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. It also states that any excess of the amount actually paid by the Utility over the amount above specified will be charged to Account 426.5, Other Deductions. The foregoing directives support conducting a direct analysis to identify Production or Transmission-related costs.

Decision

The ASCM 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 BPA proposed. (IOU, ASC0004, at 7.) BPA concurs with this need; however, these costs are already included in rate base Plant-In-Service under the Production Plant schedules. The

[7] FERC Uniform System of Accounts, Electric PART 101- *Uniform System Of Accounts Prescribed For Public Utilities And Licensees Subject To The Provisions Of The Federal Power Act*

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 subaccounts 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

The ASCM 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 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 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. (*Id.)*

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 includable 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 subaccounts associated with 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

The ASCM 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 be subject to direct analysis because some of this income may be reasonably attributable to generation. (PPC/NRU, ASC0006, at 14.)

BPA's Position

The proposed ASCM 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 includes, 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 must 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 includes, 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 the PPC/NRU proposal.

Decision

The ASCM 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 sales for resale customers who take service on that Utility's system and for whom firm system costs (both rate base and expense) are generally allocated in jurisdictional and FERC ratemaking processes. (IOU, ASC0004 at 5.) The IOUs state that 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.*) The IOUs state that RQ Sales for Resale should not be included in ASC and 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). 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, at 310.

BPA agrees in part with the IOUs on this issue. 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. In their comments on the Draft ASCM ROD, the IOUs note BPA's foregoing statement. (IOU, AS20007 at 9-10; PSE, AS20009 at 11.) The IOUs state that, for clarification, if the revenues associated with RQ sales are removed from Sales for Resale and Purchased Power, the MWhs associated with those sales revenues should be included in the calculation of ASC by adding the MWhs to Contract System Load at row 38 on tab Sch 4 - Average System Cost in the ASC template. (*Id.*) The IOUs state BPA should include this clarification and confirm the availability of this option in its Decision. (*Id.*)

PPC requests that BPA clarify the proposed treatment of this issue. (PPC, ASC0012 at 5.) Specifically, at the bottom of page 62 of the Draft ROD, the following statement is unclear: "they must also add the associated MWh from Contract System Load." (*Id*.) PPC asks whether BPA proposes to add these sales to Contract System Load, or subtract these sales from Contract System Load. (*Id*.)

BPA notes that the RQ sales are not to retail customers of the Utility and their loads are not a retail customer load. Therefore, these sales should be treated as other sales for resale revenue. Review of RQ sales in several of the FERC Form 1 filings reveals customers such as Fail Safe Corporation, Portland General Electric, Kittitas County PUD and Raft River Rural Electric Coop. BPA is therefore not convinced by the IOUs' arguments that RQ sales should not be included in Sales for Resale in ASC filings.

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. (IOU, ASC0004 at 5.) BPA agrees.

Decision

The ASCM 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 demand-side-management (DSM) programs are booked. (IOU, ASC0004 at 5.) The IOUs state that 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 that 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. Account 908 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; and engineering and technical advice to customers 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; and transportation, meals, and incidental expenses.

BPA believes an analysis should reflect whether 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

The ASCM 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 the FERC System of Accounts, Account 930.1, General Advertising Expenses, includes 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.

In their comments on the Draft ROD, the IOUs suggest that the Final ASCM ROD should specify that all conservation-related costs (not necessarily advertising and promotion costs) in Account 909 – Informational and Instructional Advertising and Account 124 – Other Investments, will be functionalized to Production. (IOU, AS20007 at 10.) PSE suggests that all conservation-related costs be functionalized to Production regardless of where they appear in the FERC Form 1 (such as in Account 909 and Account 124). (PSE, ASC0017 at 12.)

BPA agrees. Utilities will be able to functionalize all conservation-related costs to Production, regardless of the account in which they are recorded. The functionalization of conservation-related costs must be supported with enough detail so BPA can determine that they are conservation-related costs. However, if conservation-related costs are recorded in an Account that is normally functionalized to Distribution/Other, the Utility cannot perform a direct analysis on the non-conservation-related costs in the Account. All other non-conservation-related costs will be functionalized according to the functionalization rules for that Account.

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 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 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. The FERC Uniform System of Accounts for Account 930.2 definition requires the following cost items should be recorded in this Account: 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; directors' fees and expenses; publishing and distributing annual reports to stockholders; and public notices of financial, operating and other data required by regulatory statutes.

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 disagrees with the IOUs on this issue. Based on FERC's definition of Account 930.2, costs included in this account are not Production in nature and therefore should not be included in ASC. Industry association dues and conventions expenses, stockholder meetings and communications are far removed from the Production and Transmission functions of the utility. The fact that state commissions may allow Account 930.2 be functionalized using the Labor Ratio, is not sufficient reason for BPA to adopt a similar treatment for this Account. As the FERC stated in its approval of the 1984 ASCM:

> 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, if 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 this Commission's review. Therefore, the IOUs cannot logically maintain that the ASC must exactly equal the retail rates set by the State commissions, minus distribution costs and the costs specifically excluded under sections 5(c)(7) (A) and (B) and (C). 49 Fed. Reg. 39,293, 39,297 (Oct. 5, 1984)

Decision

The ASCM 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 IOUs note that state regulatory commissions regulate Utility services provided by investor-owned utilities, which include Production, Transmission and Distribution functions. (*Id.*) The IOUs claim that 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 at 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 IOUs. 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 ASCM ROD, Appendix C at page 3 and 6. In the 1984 ASCM, Account 928 was functionalized to Distribution/Other.

BPA understands that expenses included in Account 928 are related to more than just the Distribution function of utilities. However, 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 ASCM 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.[8]

In their comments on the Draft ROD, the IOUs disagree with BPA's decision to functionalize Regulatory Expenses – Account 928, to Distribution/Other. (IOU, AS20007 at 11; PSE, AS20009 at 12-13.) They argue BPA's position with respect to the functionalization of Account 928 "Regulatory Expense" is inconsistent with its position on revenue credits. (*Id.*) Under BPA's proposed ASCM, Account 447 "Sales for Resale" is functionalized to Production and Account 456.1 "Revenue from Transmission of Electricity of Others" is functionalized to Transmission. (*Id.*) Including these revenues as credits in the calculation reduces ASC. (*Id.*) The IOUs argue the expenses incurred to generate these revenues need to be functionalized in a consistent manner. (*Id.*) Those expenses include amounts included in Account 928. (*Id.*)

The IOUs state that Account 928 consists primarily of two costs. (IOU, AS20007 at 11; PSE, AS20009 at 12-13.) The first cost is the fee paid to the FERC for the right to sell energy into the market and to operate a transmission system. (*Id.*) This fee is mandated by FERC Order 582 and supports FERC's budget. (*Id.*) The amount of the fee is based on three factors: Sales for Resale, Purchased Power (Exchanges Only), and Revenues from Transmitting Power for Others. (*Id.*) All three of these factors generate revenue that BPA treats as credits in the determination of ASC. (*Id.*) Without the payment of the FERC fee there would be no revenue to credit. (*Id.*) Therefore, the IOUs argue it is inconsistent to functionalize this cost to distribution and thereby exclude it from the calculation of ASC. (*Id.*)

The second cost relates to the processing of rate cases. (*Id.*) For a regulated Utility, rates are cost-based. (*Id.*) A Utility is allowed to recover its prudently incurred costs through rates that are set by either the FERC or state regulators. (*Id.*) FERC sets the rates that determine the revenues that will be collected for transmitting energy for others, Account 456.1, and ancillary services that are included in Account 456, Other Electric Revenues. (*Id.*) Costs recovered under these rates include amounts in Account 928 that are functionalized to Transmission. (*Id.*) BPA's decision to functionalize all of Account 928 to Distribution creates an additional inconsistency where the total transmission revenue is used to reduce the ASC, but the costs recovered by those revenues are excluded. (*Id.*) Based upon a proper matching of revenues and expenses, the IOUs believe Account 928 should be functionalized on a "Direct" basis. (*Id.*) That would allow costs directly related to Production and Transmission to be considered in the determination of ASC.

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

BPA agrees that the costs of generating revenues that act as a credit to ASC should be included in ASC. These costs include the depreciation and return on investment for the resources used to generate the revenues, plus any associated operating costs. These costs are included in ASC. However, BPA continues to believe, as it did under the 1981 ASCM and 1984 ASCM, that regulatory fees are not resource costs for purposes of ASC determinations. Regulatory fees are just one of a number of prudently incurred expenses, which arguably could be considered a valid cost of doing business, but which are not resource costs incurred to conserve, generate or transmit power.

The IOUs argue that these costs should be included because they are directly related to Production and Transmission. (IOU, AS20007 at 11; PSE, AS20009 at 12-13.) Without paying these fees, the IOUs assert they would be unable to sell energy or operate their transmission system, and consequently, would have no revenue to credit against their ASCs. (*Id.*) This argument, however, proves too much. Almost any cost an *electric* Utility incurs, in one form or another, will ultimately be related to the Production and Transmission functions in some manner. BPA must draw the line on what is a Production or Transmission-related cost somewhere in order to maintain the integrity of the ASCM. Without this line, utilities would have the ability to exchange almost any cost with BPA, with the illogical result that ASC would be the "average" cost of operating the Utility, rather than the "average system cost of . . . resources." 16 U.S.C. § 839c(c)(1). FERC recognized the need for this line when reviewing the 1984 ASCM. *See* 49 Fed. Reg. 39,293, 39,296 (Oct. 4, 1984). The Commission, at that time, found that "BPA reasonably construes the [Northwest Power Act] 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." *Id.* Account 928 is one such account that includes costs the IOUs incur, but which BPA does not believe must be exchanged as a resource cost. The costs in Account 928 are costs the Utility must pay in relation to its pricing function. It is BPA's view that the regulatory fees and charges the Utility incurs in Account 928 are related to the Utility's pricing function, and as such, are a cost of doing business as an electric Utility. They are not, therefore, a type of resource cost intended to be included in ASC.

Decision

The ASCM 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.) The IOUs claim that, 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.*) The IOUs state that Common Plant appeared 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 consultation process, BPA realized that Common Plant assets and expenses included costs related to natural gas and electric operations. BPA will require that Common Plant be functionalized using direct analysis and only costs related to electric operations will be included in ASC.

Decision

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

4.4 High Water Mark and ASC Determination

Issue

Whether and how to exclude costs of resources from exchanging COUs' ASCs to be consistent with such COUs' elections to execute Regional Dialogue High Water Mark (HWM) contracts.

Parties' Positions

Snohomish states that the calculation of ASC for COUs that sign a HWM Regional Dialogue contract should be explicitly laid out in the ASCM, 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 containing Contract High Water Marks and expects all or most public preference Utility customers will choose to sign them. In such a case, the customer and BPA will agree that REP benefits will not be provided for resources added to meet post-FY 2010 load growth. To accomplish this, BPA proposes to freeze the Utility's eligible exchange load as of the time of the specified resources in the Utility's HWM contract, currently FY 2010. In the event any public preference customer declines to sign a CHWM contract, BPA plans to offer requirements contracts without CHWMs. Such customers can execute such contracts and participate fully in the REP.

Evaluation of Positions

In the draft ASCM ROD, BPA stated its expectation that Utility customers with a CHWM contract will agree that REP benefits will not be provided for resources added to meet post-FY 2010 load growth, and to freeze the Utility's eligible exchange loads as of the time of the specified resources in the Utility's HWM contract, currently FY 2010. After further review, BPA is clarifying how it will make these adjustments. In this clarification BPA is proposing to (1) tie the resources added to meet post-FY 2010 load growth to those resources not included in the Utility's CHWM calculation, and (2) tie the percentage of exchange loads to the RHWM load calculation. Those resources and the percentage will be established in the CHWM process.

WPAG states that the proposed ASCM reserves to BPA the right to modify the ASCM to accommodate the Tiered Rates Methodology (TRM) finally adopted, including the ability to exclude from the ASC calculation of preference customers who sign HWM power contracts resource costs that would otherwise be includable in their ASC. (WPAG, ASC0008 at 6; WPAG, AS20004 at 5.) WPAG also argues 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. (*Id.*) The right to participate in the REP is statutory in nature, and cannot be conditioned on the type of contract a customer signs. (*Id.*) WPAG does not object to BPA retaining the right to make appropriate changes to the ASCM. (*Id.*) However, modifications to the ASCM must be done in a manner that is consistent with other provisions of the Northwest Power Act. (*Id.*) Preference customers cannot be forced to forego one statutory right in order to exercise another. (*Id.*) WPAG states 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. (*Id.*)

BPA understands WPAG's concerns but does not believe that a Utility would be foregoing one 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-2010 resources, or it can decline to sign such a contract, in which case BPA will offer a contract without this limitation. The latter, like the CHWM contract, will satisfy BPA's statutory obligation to meet net requirements.

The Long-Term Regional Dialogue Policy ROD published in July 2007 outlines the tiered rates approach, and the Draft Tiered Rates Methodology (March 7, 2008) reflects how the REP fits into that pricing construct. As currently proposed, the costs of the REP will be allocated to the Tier 1 Composite cost pool. Customers exchanging the costs of new resources added to meet load growth 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 currently 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 resources that underlie Tier 1 rates (Their 1 System Resources). This objective would be compromised if the costs of a customer's new resources were melded with the costs of Tier 1 System Resources through the REP.

Snohomish states that the calculation of ASC for COUs who sign a HWM Regional Dialogue contract should be explicitly laid out in the ASCM, not in the RPSA. (Snohomish, ASC0009 at 3.) Snohomish 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. (*Id.)* Snohomish states that it is likely that it will need to replace the current long-term PPAs with third party providers; these are not additions but replacements that maintain Snohomish's load service obligations. *(Id.*) Snohomish states that it believes that the mechanism for the HWM ASC calculation should be included in the ASCM. *(Id.)*

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 pools, the ASCM 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 require major refurbishment or must be replaced. Instead of trying to keep track of all the individual resource costs, BPA is adopting the following simplified approach.

1. Determine the Rate Period High Water Mark (RHWM) System Load.
2. Determine the RHWM Exchangeable Load (Residential/Small Farm Load).
3. During the Average System Cost Review process the Utility will submit the data necessary to determine the fully allocated unit cost of resources in excess of the resource amounts used to calculate its Contract High Water Mark (CHWM).
4. Calculate the Utility's Total Unadjusted Contract System Cost (CSC) as described in the ASCM.
5. Calculate a load growth credit {(Current System Load minus RHWM system Load) * Unit costs from 3 above}.
6. Total Exchangeable Contract System Cost = Total Unadjusted CSC minus load growth revenue credit (from 5 above).
7. HWM Average System Cost = Total Exchangeable Contract System Cost/RHWM System Load.

This approach eliminates the necessity of trying to track individual resource costs and the costs of any associated replacements through time. Eligible Exchange Loads will be determined in Step 2. Tying the Eligible Exchange Loads to the RHWM amounts reasonably achieves the policy goal of keeping the costs of resources associated with serving load growth out of the Tier 1 cost pool.

In its comments on the Draft ROD, Snohomish notes that BPA committed to establishing the ASCs for COUs in the ASCM, not in the RPSA. (Snohomish, AS20006 at 2.) Snohomish then states that it assumes Section 21 of the RPSA template will be deleted. (*Id.*) Despite the fact that COUs' ASCs will be established based on the requirements of the ASCM, this does not dictate that there will be no provision in the RPSA concerning the exclusion of costs of resources from exchanging COUs' ASC to be consistent with such COUs' elections to execute Regional Dialogue High Water Mark (HWM) contracts. The need for such a provision, or lack thereof, and the content of any such provision will be determined in BPA's separate administrative proceeding to establish the RPSAs.

PSE suggests that a draft methodology for determining the "fully allocated unit costs of new resources used to meet above High Water Mark load growth" referenced in the Draft ROD at page 69 should be proposed by BPA for comment and, based on those comments, a final methodology for such determination should be included in the ASCM ROD. (PSE, ASC00 at 14.) BPA understands PSE's concerns, but does not think it needs to be addressed through a separate comment period and then included in the ASCM ROD. Instead, BPA will work with utilities to come up with an implementation of this area prior to the review period of the FY2012-13 ASC filings.

Decision

The ASCM will revenue credit a Utility's Contract System Cost for load growth valued at Step 3. The Utility's ASC will be calculated as its total Contract System Cost divided by its RHWM System Load. This ASC will then be applied to the Eligible Exchange Load determined 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 for 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 percent. (*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.*) PPC generally supports the idea that all post-September 1, 1979, resources and long-term power purchases should be used to determine the cost of serving NLSLs, and supports the proposal that no ASC can ever fall [increase] because of the exclusion of costs of serving NLSLs. (PPC, AS20003 at 6.)

BPA's Position

Endnote d of the proposed 2008 ASCM did not change the methodology for determining the cost of resources used to serve NLSLs from the procedures included in the 1981 ASCM, Footnote 15, and the 1984 ASCM, 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 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 five 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 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). This preclusion has been reflected in BPA's 1981 and 1984 ASCMs through a prescribed treatment contained in an ASCM footnote. This treatment is 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.

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 baseload 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 considered 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 will include all 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 baseload 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. Arguments could occur over what constitutes a "major" upgrade or whether the relicensing of a hydro project changes anything other than the date that 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 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.

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* sufficient to serve 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.

(IOU, ASC0004 at 8.) 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 ASCM. BPA does not intend to change that alignment of policies.

In their comments on the Draft ASCM ROD, the IOUs state they do not support BPA's decision to change the resources being used to determine the cost of serving NLSLs from post-Act baseload resources and power purchase contracts greater than 5 years in duration to all post-Act resources and power purchase contracts greater than 1 year in duration. (IOU, AS20007 at 12.) They also oppose BPA's decision to limit a Utility's ASC to not increasing as a result of excluding the costs of resources used to serve NLSLs. (*Id.*) BPA states that "[r]eview of any current integrated resource plan (IRP) 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." The IOUs state the implication is that utilities are not adding baseload resources to serve load. (*Id.*) The IOUs believe this is not correct. (*Id.*) The IOUs state, for example, in 2007 PGE added Port Westward, a 400 MW baseload facility, and PacifiCorp recently added two major baseload plants, the 550 MW Lake Side facility and the 550 MW Current Creek facility, and is purchasing the Chehalis plant. (*Id.*)

BPA agrees in part with the IOUs' argument that they are still relying on baseload resources for *a portion* of their future resource requirements. Review of any of the IOUs' IRPs will show renewable resources, especially wind, plays a significant role in meeting utilities' future resource requirements. Puget's recent acquisition of Wild Horse and Hopkins Ridge, which total 379 MW of capacity, and PGE's acquisition of Biglow Canyon with between 400 and 450 MW of capacity when completed in 2009, indicate that baseload resources are not the only resources used to meet future requirements of IOUs. As stated above, the NLSL resource cost determination language was written in 1980 and needs to be updated to reflect the current resource acquisition environment of exchanging utilities.

PSE opposes BPA's decision to prevent a Utility's ASC from increasing as a result of excluding the costs of resources used to serve NLSLs. (PSE, AS20009 at 14.) PSE argues any such limitation is arbitrary, not adequately supported in the record, and is unsupported by the language of the Northwest Power Act. (*Id.*) Puget argues nothing in the Northwest Power Act requires that the exclusion of the costs of resources to serve NLSLs not increase the Utility's ASC. (*Id.*) In response to this argument, the Northwest Power Act and its legislative history demonstrate a consistent policy with regard to NLSLs. 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—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 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). The legislative history of the Act notes that "[a] higher rate will apply to the load growth of the region's investor-owned utilities and for the power needed by preference utilities to meet any 'new large single loads' they may have (sec. 7(f))." H.R. Rep. No. 96-976, Pt. II, 96th Cong. 2d Sess. 36 (1980). Similarly, the legislative history notes that "Section 7(f) is the rate directives for the so-called 'new resources rate' that BPA will charge customers for sales other than those to which a different rate directive applies. . . . It will be used, for example, for power sold to investor-owned utilities to meet their net requirements, and to power sold to preference customers to meet their new large single loads." H.R. Rep. No. 96-976, Pt. II, 96th Cong. 2d Sess. 53 (1980). Congress recognized that "[u]nder this bill, rates for increased loads resulting from any new commercial and industrial activity ('New Large Single Loads', section 3(12)) are excluded from the Federal base resource rate. Thus, any Utility seeking additional power to serve such a load would be charged a rate equivalent to the new resource cost. This new resource cost should be the same or higher than the cost to utilities in other regions to serve such load. This provision should help to narrow, rather than expand, the Northwest's advantage in attracting new industry through lower cost electricity." H.R. Rep. No. 96-976, Pt. I, 96th Cong. 2d Sess. 43-44 (1979). The foregoing excepts demonstrate Congressional intent that NLSLs would be served at marginal rates, that is, Congressional policy was to discourage NLSLs through high rates rather than to encourage NLSLs by charging low rates.

In the context of the REP, the Northwest Power Act provides that a Utility's average system cost, as determined by the Administrator under the ASCM, "shall not include—the cost of resources in an amount sufficient to serve any new large single load of the Utility." 16 U.S.C. § 839a(13). It is important to note that this language does not refer to costs of resources used to serve an NLSL, but rather costs of resources in an amount sufficient to serve an NLSL. The legislative history of the Northwest Power Act notes that "[t]his is an important definition in many respects. Although the Administrator will be obligated to sell power to meet these loads, power for new large single loads will be sold at the section 7(f) rates *which are likely to be the marginal cost of power*. Consequently, enterprises new to the Region will have to pay rates as least as high as rates charged for electric power in other regions unless other electric power consumers want to subsidize the industry. . . . This definition also has application under the section 5(c)(1) exchange. The 'average system cost' of the power sold to the Administrator by investor-owned utilities pursuant to this section must exclude the cost of resources needed to serve a new large single load. Thus, the cost of serving new large single loads will not be averaged in BPA rates applicable to sales for general requirements of preference customers and for IOU's, [sic] residential and small farm customers." H.R. Rep. No. 96-976, Pt. I, 96th Cong. 2d Sess. 51-52 (1980) (emphasis added). Once again, Congress indicated that costs of serving NLSLs are not intended to be subsidized. In the 2008 ASCM, BPA has proposed an approach for calculating and removing the costs of serving an NLSL. To the extent this approach would *increase* exchanging utilities' ASCs, it would provide an incentive to acquire NLSLs and be contrary to Congressional intent. For this reason, BPA believes it is appropriate to establish a rule that any adjustment to remove the costs of serving NLSLs will not increase utilities' ASCs.

As noted previously, PPC/NRU suggest there are essentially two ways of determining the cost of resources sufficient 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.*) Alternately, the NLSL resource cost determination should be based on the projected cost of power purchases from the wholesale market.

BPA believes that an approach more consistent with the approach used in forecasting the utilities' ASCs would be a more appropriate manner of forecasting the cost of serving NLSLs than a method based on solely on the projected cost of power purchases from the wholesale market. The following outlines a reasonable process for forecasting the NLSL load and cost of serving the NLSL load.

1 Identify the "Base Period" post-1979 resources.
2 Calculate the fully allocated costs of the "Base Period" post-1979 resources (fully allocated costs include return, depreciation expense, O&M, Fuel, allocated A&G, and Property taxes).
3 Escalate the fully allocated costs to the "Exchange Period" using the general method for the escalation of all Base Period costs.
4 Adjust the forecasted resources' costs by the forecasted transmission costs.
5 Calculate the fully allocated costs for major resource additions.
6 Add the fully allocated costs for major resource additions to the escalated fully allocated costs of Base Period post-1979 resources.
7 The cost to serve NLSL load will change when ASC changes due to resource additions (Resource Addition Online date).
8 For the Exchange Period, the Base Period NLSL load will equal the Base Period NLSL load.

Decision

The ASCM will determine the cost of serving NLSLs using the fully allocated cost of all escalated Base Period post-September 1, 1979, resources and major resource additions and long-term power purchases (5 years or longer contracts) used to determine Exchange Period ASCs 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, BPA will not allow a Utility's ASC to 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

Although 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 recording 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, differ from the proposed BPA functionalization allocation, which 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.*) Snohomish claims the 70/30 split does not allow Snohomish to reflect its actual, documented conservation expenditures. (*Id.*) Snohomish argues the 90/10 ratio more accurately reflects Snohomish's conservation expenditures that should be included in ASC Production costs. (*Id.*)

BPA agrees that a conservation functionalization ratio of 70 percent to Production and 30 percent 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 consultation 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 PacifiCorp completely out of the conservation acquisition and program development process by creating the ETO. PGE and PacifiCorp 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, levied on all retail sales of electricity, but many of the conservation programs are delivered by the utilities.

Decision

The ASCM will no longer use ratios to functionalize conservation program costs or revenues sent to organizations like the ETO that perform conservation programs for Utilities. BPA will examine conservation program costs and Public Purpose Charges on a Utility-by-Utility basis.

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 percent of the OPPC to Production. (IOU, ASC0004 at 6.) In addition, they support functionalization of the Montana Universal Systems Benefit Charge to Production. (*Id*.) WUTC also supports inclusion of the OPPC in ASC and argues that conservation related "tariff riders" should be allowed as an allowable cost in ASC. (WUTC, ASC0005 at 11.) Similarly, OPUC argues that 95.5 percent of the OPPC charge should be functionalized to Production. (OPUC, ASC0010 at 6-9.)

PPC/NRU, WPAG and PRC argue that 63 percent of OPPC funds should be allocated to Production and 37 percent should be allocated to Distribution/Other. (PPC/NRU, AS20003 at 6-9; WPAG, AS20004 at 2; PRC, ASC0001 at 3.)

BPA's Position

The proposed ASCM functionalizes 70 percent of the OPPC to Production and 30 percent 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 OPPC funds are made monthly by the Utilities to the following organizations in the following percentages: Energy Trust of Oregon (ETO) -73.8 percent Education Service Districts (ESD) - 10.0 percent Oregon Housing and Community Services (OHCS) - 16.2 percent. 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 percent, above market cost of renewable energy resources – 19 percent low-income weatherization – 13 percent, low-income bill payment assistance – 5 percent. 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 a 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. Although 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 a Utility's costs that are excludable from its 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 Utilities' 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 percent/30 percent 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 percent to Production. (*Id.*)

OPUC supports BPA's proposal to treat costs for OPPC related to the acquisition of conservation and renewable resources consistent 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.*) OPUC believes that 95.5 percent 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 percent), 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.*)

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. (*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.*)

PPC/NRU, WPAG and PRC argue that 63 percent of OPPC funds should be allocated to Production and 37% should be allocated to Distribution/Other. (PPC/NRU, ASC0006 at 6-9; WPAG, ASC0008 at 2; PRC, ASC0001 at 3.) PPC/NRU, WPAG and PRC 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, ASC0006 at 6-9; WPAG, ASC0008 at 2; PRC, ASC0001 at 3.) BPA acknowledges that it may not have the right to 'audit' the programs of the OPPC recipient organizations in the strict use of the word, 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 may disallow those costs.

PPC/NRU, WPAG and PRC all argue that they are not clear what standards BPA's auditors would use to determine an "allowable" expense for the purposes of the ASCM. (PPC/NRU, ASC0006 at 6-9; WPAG, ASC0008 at 2; PRC, ASC0001 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 argue that BPA should functionalize 63 percent of conservation costs to Production and 37 percent to Distribution/Other because not all of OPPC's programs are cost-effective conservation programs. (PPC/NRU, ASC0006 at 6-9; WPAG, ASC0008 at 2; PRC, ASC0001 at 3.)

BPA agrees that a conservation functionalization ratio of 70 percent to Production and 30 percent to Distribution (70/30) does not accurately reflect the functional nature of OPPC conservation, or any other exchanging Utility's conservation program or Public Purpose Charge. 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 consultation 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 PacifiCorp completely out of the conservation acquisition and program development process by creating the ETO. PGE and PacifiCorp fund the ETO activities through a Public Purpose Charge equal to 3 percent 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.

PPC does not support the Utility-specific functionalization of the funds expended by the Energy Trust of Oregon. (PPC, AS20003 at 6.) SB 1149 clearly states that 37 percent of the Oregon Public Purpose Charge (OPPC) funds are to be spent on above-market renewable energy resources or assistance to low-income households (via weatherization or bill payment). (*Id.*) PPC does not understand how a Utility-specific investigation by BPA of statutorily-directed OPPC funds could yield any other results, unless the ETO violates Oregon law. (*Id.*) As there is no reason to believe that the ETO will violate Oregon law, the Utility-specific approach needlessly creates complications and increases the cost of implementing the new ASCM. (*Id.*) The simpler approach would be to adopt the rule that 63 percent of OPPC funds will be functionalized to Production. (*Id.*) BPA disagrees with PPC's argument that low-income weatherization is not conservation and therefore not an exchangeable cost. BPA strongly believes that prudently incurred costs related to weatherization of homes qualify as conservation and should be allowed in ASC, irrespective of the income level of the beneficiaries of the program. BPA also disagrees with the PPC that payments by the ETO for above-market renewable energy resources should not be allowed in ASC. During BPA's ASC Expedited Process, BPA heard concerns from several Utilities about supplying information on new renewable generation resources they may acquire during the 3-year period following submittal of their Base Year ASC filings. The Utilities noted that the current Renewable Portfolio Standards (RPS) in place in PNW states have them bidding on the same renewable resources to meet current RPS standards. They stated that the competition for renewable resources will only get worse if, as expected, the PNW states increase the percentage of renewable resources that Utilities must have in their resource portfolios. BPA concurs with the Utilities' view that PNW states will likely increase the RPS standards in the future, resulting in increased demand for all types of renewable resources. BPA believes that above-market acquisition of renewable resources under the auspices of organizations like the ETO will help bring to market new and innovative types of renewable resources that will over time help Utilities meet existing and future RPS requirements for the long term. BPA finds that 16 percent of the OPPC total funds designated for renewable resources is a valid resource cost that should be included in ASC. The amount spent "above market" goes toward promising technologies or resources that are only slightly above a Utility's cost-effectiveness threshold. The ETO reviews the resources and grants the assistance to those that may offer benefits if the technology is widely adopted. This portion of the ETO budget is essentially an R&D program for renewable resources. However, BPA does agree with the PPC that low-income bill payment assistance is not a conservation resource and will not include such costs in ASC.

PSE suggests that BPA allow for review and comment by interested parties on its proposed determination of the exchangeable cost of each conservation program. (PSE, AS20008 at 15.) BPA agrees with PSE on this issue. All costs included in a Utility's ASC filing are subject to review and comment by parties to the ASC review process. There is no need to separately mention in the ASCM that conservation program costs will be reviewed by interested parties. All components in a Utility's ASC filing are subject to review and comment during the ASC review process.

Decision

The ASCM will no longer use ratios to functionalize conservation program costs or revenues sent to organizations like the ETO that 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.)

PPC argues that conservation-related advertising and promotion costs should be functionalized to Production. (PPC, AS20003 at 6.)

BPA's Position

BPA's proposed ASCM excluded the cost of conservation-related advertising and promotion expenses from 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 would 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 were not viewed as resource costs and therefore were not includable in ASC. *Id.*

WUTC states it does not believe 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 PF Preference or PF Exchange rates. (WUTC, AS20004 at 12.) Just as WUTC argued for symmetry in the treatment of transmission costs, WUTC recommends 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 WUTC that conservation-related advertising costs 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 is especially true given the large amount of conservation utilities will be required to acquire in the future. 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 costs. 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 determine what constitutes conservation-related advertising expenses.

PPC disagrees that conservation-related advertising and promotion costs should be subject to Utility-specific analysis. (PPC, AS20003 at 6.) PPC argues these costs should be functionalized to Production. (*Id*.) Utility-specific analysis brings only needless complications. (*Id*.) BPA disagrees with the PPC on this issue. Many of the current conservation programs involve market transformation activities to change customers' attitudes toward purchasing energy efficient appliances and other investments that reduce the need for electricity. BPA believes that conservation-related advertising is a legitimate resource cost and will therefore allow utilities to include such costs in ASC.

Decision

The ASCM will allow conservation-related advertising and promotion costs in 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.)

PPC argues that revenues received from "tariff riders" should be excluded from ASC. (PPC, AS20003 at 7.)

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," the revenue from which is administered to achieve conservation by the Energy Trust of Oregon, Oregon Educational Service Districts and Oregon Housing and Community Services. (WUTC, AS20002 at 6) Under Oregon law, utilities in that state no longer operate their own conservation programs. (*Id.)* 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. (*Id.*) 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 ROD. 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. WUTC's proposal would "double count" conservation costs; once when the tariff rider revenue is included as an expense on the Utility's ASC filing, and again through the inclusion of conservation program costs from the Utility's FERC Form 1.

In its comments on the Draft ROD, the IOUs state that, for clarification, the revenues recovered under the conservation tariff riders are also recorded as a liability in Account 908, as amortization of the conservation regulatory asset. (IOU, AS20007 at 14.) The IOUs argue to the extent all of the conservation costs booked in Accounts 908 and in the related conservation regulatory asset are included in ASC, it is not necessary to include the revenue associated with conservation riders as an expense. (*Id.*) They state that if any portion of these costs in Account 908 and/or the costs in the conservation-related regulatory asset is not included in the ASC for some reason, the corresponding portion of revenues associated with the rider should be included in ASC as a Production-related cost and included in the Utility's allowable exchangeable contract costs. (*Id.*) BPA disagrees with the IOUs on the inclusion of tariff riders in ASC for the reasons stated above. The revenues from the tariff riders are used to fund conservation programs at the Utilities, which are allowable costs in utilities' ASC filings. To include tariff riders in addition to the associated conservation costs would be double counting.

PPC agrees that revenues received from "tariff riders" should be excluded from ASC. (PPC, AS20003 at 7.) PPC states that if conservation costs are funded with revenues from such riders, those costs will be included in the ASCs of individual IOUs. (*Id.*) This is different from the OPPC, because expenditures by the ETO will not show up in an ASC filing. (*Id.*) PPC notes that to add the revenues themselves would double-count such costs, and artificially inflate ASCs. (*Id.*) BPA agrees.

Decision

The ASCM will not allow the inclusion of "Tariff Rider" revenue as an expense in utilities' 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 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 ASCM, 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 ASCM, BPA stated that "in developing an ASCM 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 ASCM:

> 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 ASCM. 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 ASCM, 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 ASCM 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 ASCM 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 ASCM. 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 that would affect ratemaking. 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.

IPUC strongly supports inclusion of equity return in the proposed ASCM. (IPUC, ASC0003 at 8.) The current exclusion of this cost in the 1984 ASCM 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.*)

WUTC strongly supports BPA's proposal to include ROE as an allowable cost component in ASC. (WUTC, ASC0005 at 14.) 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, 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.*)

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.*)

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.*) 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.*)

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.*)

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 review 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 ASCM. 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 that would affect ratemaking. 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. 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.) 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.)* In addition, BPA notes that the IOUs and state commissions have seen the severe results of a prior attempt to include terminated plant costs in return on equity—namely, revision of the ASCM, lower ASCs, and lower REP benefits. These impacts have occurred since 1984 under BPA's implementation of the REP. BPA does not believe exchanging utilities or commissions would seriously consider undertaking such actions again.

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 earned by the IOUs. (*Id.)* BPA believes using actual returns would be inappropriate. BPA develops wholesale power rates using projected test years and will develop projected ASCs so that they are aligned with BPA's rates. BPA uses the allowed rate of return from state commission orders, in part, to develop these projected ASCs. The Base Period ASCs filed by IOUs and based on their most recent FERC Form 1s are the starting points 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. 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.

In its comments on the Draft ASCM ROD, WPAG states that one of the important considerations in determining ASC for use in the REP calculation is that the ASC must reflect the ASC to residential customers. (WPAG, AS20004 at 3.) If rates to customers are based on a revenue to cost ratio, the residential ROE included in rates will be equal to the overall ROE for the Utility. (*Id*.) However, for most utilities, actual residential rates are set based on a revenue to cost ratio less than 1. (*Id*.) As such, the ROE should be adjusted downward to reflect the residential class ROE allowed in rates. (*Id*.) WPAG's argument is founded on an improper assumption. The REP is based on the comparison of Utilities' respective system costs (Production and Transmission) with BPA's system costs, not revenue recovered from a customer class with BPA's system costs. Likewise, return on equity is determined for the Utility as a whole and not by individual customer classes. BPA does not know of a state commission that determines rate of return by customer class for electric utilities.

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 IOUs' ratemaking process. (*Id.* at 8.) Similarly, 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.) PPC/NRU's arguments are premised on speculation of bad faith by regional state regulatory bodies. Although a single public Utility commissioner once permitted terminated plant costs in a Utility's retail rates, this should not be attributed to state commissions generally. With few historical exceptions, state Utility commissioners are dedicated to upholding state and Federal law and perform their responsibilities with integrity. In addition, 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 regional power 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 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.) This argument once again assumes actions in bad faith by the state regulatory bodies. Also, this argument goes to BPA's review of ASCs, not to the merits of including ROE as a resource cost in ASC. The ASCM contains provisions that allow BPA and its customers to intervene in state retail rate proceedings in order to obtain information relevant to determining ASC. This includes information concerning ROE. In addition, 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.)* In response, BPA notes that commissions allow rate of return for electric utilities based on the factors specific to the electric Utility operations, irrespective of the technique used to measure return on equity. For example, if a state commission uses Capital Asset Pricing Model (CAPM) or one of its variants, the Utility return is based on the comparable risk of holding a Utility stock versus other investments. In determining return on equity using CAPM, state commissions determine the relative risk of the electric Utility, not of other non-regulated subsidiaries, such as coal, real estate, or commodity speculation. In addition, PPC/NRU *did not* provide examples of where the Idaho or Washington Commission increased the ROE of either Puget or Avista, due to changes in the gas operations or subsidiaries of those two companies. PPC/NRU only stated that ROE "can change", not that ROE *did* change, which PPC/NRU supported with documentation from commission rate orders.

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.)* In response, BPA notes that the converse could also be true, that in periods of high inflation and rapid increases in interest rates such as occurred in the mid-1970's, BPA would under compensate the IOUs for their cost of capital. BPA also notes that State commissions set ROE for an IOU's retail rates for a prospective rate period. Although there are limited conditions in which commissions allow subsequent cost true-ups, these conditions concern costs that are subject to significant fluctuation, such as fuel costs. Commissions do not allow true-ups for ROE. In the event a Utility does not file for a rate change for a number of years, the State commission has the ability to file for an investigation on its own motion to address the issue. *See, e.g*., ORS 756.515. Indeed, the OPUC has done so. *See* Order No. 07-220, Public Utility Commission of Oregon, Staff Investigation into the Earnings of Cascade Natural Gas Corporation, June 5, 2007. In any event, the fact that the circumstances described by PPC/NRU could exist would not require the exclusion of ROE from ASC but at most would suggest a possible adjustment in very limited circumstances. As discussed elsewhere in this Record of Decision, BPA has rejected the IOUs' proposals to true up all costs included in ASC. The reasons for this rejection are equally applicable here. In addition, the circumstances described by PPC/NRU could have occurred under the 1981 ASCM or the 1984 ASCM. BPA, however, did not require any adjustment to ROE in its prior ASC Methodologies

PPC disagrees with the proposal to include ROE in ASC. (PPC, AS20003 at 7.) PPC claims BPA's arguments against the WPAG position on projected versus actual returns are disingenuous. (*Id*.) For the purpose of setting wholesale rates, projected and actual data are used in many circumstances; for example, projected data are used to set rates, but actual data are used for rebates, surcharges, and the calculation of accumulated financial reserves. (*Id.*) Such actual reserves then normally go into the calculation of projected rates. (*Id.*) Nothing should stop BPA from (a) using actual ROEs to reset ASCs once actual results of operations have been submitted to state regulatory commissions, and then (b) adjusting REP payments to reflect actual ROEs, rather than projected or authorized ROEs. (*Id.*) Furthermore, including ROE in ASCs as proposed by BPA will likely complicate ASC reviews, because the ASCM allows BPA to change ROEs from state-allowed levels. (*Id.*) This means that ROEs will be litigated, in effect, twice: once before the state commission and a second time before BPA. (*Id.*)

BPA respectfully disagrees with PPC. BPA's proposal is consistent with general principles of Utility ratemaking, where rates are developed on prospective and forecasted data. BPA, and the majority of its customers, have purposefully attempted to simplify the REP and the ASCM. One of the major means of simplification was moving away from the "jurisdictional approach" and true-ups to actual results. If ROE were subject to true-ups, all costs included in rates could equally be argued to require true-ups. Indeed, the IOUs advocate a true-up approach for all costs included in retail rates, a proposal BPA has rejected. This would add extraordinary and unnecessary complexity to BPA's establishment of ASCs. Thus, using actual ROEs to reset ASCs once actual results of operations have been submitted to state regulatory commissions, and then adjusting REP payments to reflect actual ROEs, would introduce significant complications. Additionally, BPA does not believe that there will be significant litigation of the state authorized ROE before BPA, especially if there is a complete record before the state commissions. Furthermore, the fact that the ASCM allows BPA to change ROEs from state-allowed levels *favors* BPA's non-exchanging Utility customers. PPC essentially complains that BPA and other interested parties will have the opportunity to carefully review ROEs and comment on such ROEs during the ASC review process. The Northwest Power Act prescribes that certain costs that must be excluded from utilities' ASCs. It is BPA's responsibility to ensure those provisions are enforced, and if some duplicative administrative litigation may occur to achieve those ends, such would be a small price to pay.

PPC argues there are two additional reasons to exclude ROE from ASC. (PPC, AS20003 at 7-8.) First, BPA relies on an argument that the Citizens Utility Board (CUB) will effectively monitor retail rate development in Oregon to ensure that (a) terminated plant costs are excluded from rates, and (b) ROE will generally exclude inappropriate costs. (*Id.*) This reliance is misplaced. (*Id.*) CUB's positions in the current WP-07S rate case clearly oppose the protection afforded to BPA's preference customers under section 7(b)(2) of the Northwest Power Act, and support proposed changes in the ASCM that would increase ASCs and thus subsidies paid by preference customers.[1] (*Id.*) This is not a surprising result. (*Id.*) CUB was formed to protect the residential customers of the state of Oregon. (*Id.*) If subsidies are available for such customers from other ratepayers in Oregon, CUB should be expected to argue in favor of such subsidies. (*Id.*) However, CUB should *not* be expected to argue in favor of policies or decisions that will protect the regional ratepayers who are the source of such subsidies for Oregon residential customers, and BPA should not rely on CUB to protect the interests of BPA's preference customers in state rate cases. (*Id.*)

PPC's argument is based on comparing apples to oranges in the context of ROE. PPC cites CUB's positions in BPA's WP-07 Supplemental Proceeding, more specifically, CUB's position on the section

7(b)(2) rate test. The fact that CUB's position on the 7(b)(2) rate test differs from PPC's position in not remarkable. Indeed, it is expected. Section 7(b)(2), however, is not the same issue as whether ROE should include terminated plant costs. PPC's argument that CUB should not be relied upon to argue against the inclusion of terminated plant costs in ROE is refuted by the history of the REP and Oregon's retail ratemaking proceedings. When terminated plant costs were previously included in PGE's retail rates, it was consumer interests like CUB that opposed the inclusion of such costs in rates. Indeed, the consumer interests challenged the inclusion of such costs in retail rates before the Oregon courts and prevailed in their litigation. Terminated plant costs are precluded from inclusion in ASC by Federal law and are precluded from inclusion in Utilities' retail rates in Oregon. Thus, CUB's interest, BPA's interest, and, indeed, PPC's interest in excluding terminated plant costs are shared. Also, BPA does not argue that CUB is the sole entity to provide oversight of Utilities and the OPUC. BPA used CUB for illustrative purposes. There are numerous parties that can and will participate in the state ratemaking proceedings, including BPA and its Utility customers that are not participants in the REP. Through intervention by these parties in the state ratemaking proceedings there should be significant guarantees that costs such as terminated plant will not be included in the authorized ROE.

Second, PPC claims that BPA's discussion of this issue demonstrates an insufficient understanding of the complexities of retail ratemaking, and the opportunities that different effective ROEs will be paid by different customer classes. (PPC, AS20003 at 8-9.) That is, a state commission could decide that a single ROE of, say, 12 percent should be used to determine the cost of capital of an IOU, and at the same time make other decisions that reduce costs paid by industrial ratepayers. (*Id.*) What is the "appropriate" ROE under these circumstances: the 12 percent included in the nominal calculation of the cost of capital, which under BPA's approach would go directly into ASC, or the average ROE effectively paid by different customer classes after all adjustments are taken into account? (*Id.*) Again, this strongly suggests that ROE will be litigated twice: once at the state level and again in the BPA ASC review. (*Id.*) Every decision made by a state commission that could have any bearing on effective ROE will have to be taken up again at BPA. (*Id.*) If BPA consistently rejects arguments from preference customers regarding "appropriate ROE" in its ASC reviews, state commissions will learn that it is acceptable to increase ROEs while shifting other costs away from industrial customers. (*Id.*) This is a form of learning that BPA should not encourage. (*Id.*) As stated previously, the ROE allowed by a regulatory commission applies to the Utility's total rate base, not to just the rate base amount used to serve residential customers. Similarly, ASC is based on a Utility's total production and transmission related costs, not just the portion of costs allocated to the residential class of customers. Therefore, the appropriate ROE is the ROE included in the Utility's cost of capital, which applies to total rate base. The PPC argument relates to who receives the benefits of the REP, not to what the appropriate ROE should be for calculating ASC. The ASC is independent of the customer cost allocation decisions of the regulatory commissions.

BPA previously addressed the argument that ROE will be litigated twice. This actually ensures, to PPC's benefit, that the issue of whether improper costs have been included in ROE will receive a thorough review. Furthermore, the REP is based on the premise of comparing system costs (Production and Transmission), not revenue recovered from a customer class. There is sufficient oversight by the various customer classes in the state rate proceedings, BPA, BPA's non-exchanging Utility customers, and others to limit any cross-subsidizing by the state commissions in an effort to "game" the REP.

Indeed, this is another circumstance where CUB would an effective advocate. If the OPUC attempted to increase ROEs and shift costs away from industrial customers and on to residential consumers, CUB and other consumer interests would be motivated to oppose such actions.

PRC believes that if ROE becomes part of the ASCM, 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 IOUs. (PRC, ASC0001 at 1-2.) 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. (*Id*.) 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. (*Id*.) 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. (*Id*.) This later feature of cooperative equity planning is analogous to an IOU determining dividend levels for its shareholders. (*Id*.) A cooperative has real and perceived "risk" just as an IOU has. (*Id.)* Similarly, that risk typically translates into a higher cost of equity than debt. (*Id*.) BPA's initial proposal was to use just the COU's weighted cost of debt as a proxy for weighted cost of capital. (*Id*.) Unless the IOUs' cost of capital is similarly calculated, COUs will be disadvantaged in the determination of ASC. (*Id*.) Therefore, BPA should allow COUs to include an ROE in the determination of the weighted cost of capital in their ASC filings. (*Id*.) For a cooperative, this ROE should be based upon the equity planning goals adopted by the COU's Board, which is a cooperative's governing body. (*Id*.) Similar considerations should be given to other forms of COUs, such as municipals and PUDs, in the determination of ROE to be included in ASC determination. (*Id.)*

BPA believes a COU should receive a return on equity, but not based on the approach PRC advocates. BPA is providing COUs a return on "equity" that equals the rate base times the weighted cost of debt. Thus, the COUs' return will include the weighted cost of debt times the outstanding debt *and* the weighted cost of debt times the net assets or equity portion of the balance sheet. BPA believes this is greater than the Debt Service Coverage requirement in bond covenants and is a good proxy for the equity planning goals requested by PRC.

Decision

The ASCM 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 or other prohibited costs. 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 of such taxes 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 when 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 2008 ASCM, 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 IOU's cost of resources would be understated. When calculating the revenue requirement for an IOU, 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 ASCM, 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. (*Id.*) Similarly, the tax exempt status of preference agencies does not require the exclusion of income taxes from ASC. (*Id.*)

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 an IOU's 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.*)

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.*) WUTC also 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 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 that Federal income taxes are not a cost of resources. 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 20.) 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 IOU's cost of resources would be understated. When calculating the revenue requirement for an IOU, 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 ASCM, BPA is also proposing to gross up the equity component by the Federal income tax rate when determining an IOU'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.) WPAG states BPA should not use the marginal Federal tax rate in the ASC calculation because IOUs' effective marginal tax rates are always below the marginal tax rate. (*Id.)* The IOUs 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 argue the opposite. PPC/NRU 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.) 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 and 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. (*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.*)

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 above and for the reasons stated 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 ratemaking are due to a variety of factors having to do with the Federal tax code, Federal 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 of what can easily described as one of the most complex, contentious and longest running issues 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 use accelerated depreciation for 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, and ballot measures that continues today in many parts of the United States.

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 increased the workload of the OPUC staff. 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 128 and 129. 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. *See* 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: inter-period income tax allocation, accelerated depreciation, investment tax credits, inter-company tax allocation, and intra-company tax allocation. *Id.* at 17-5. For example, inter-period 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's 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 ASCs 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 and other costs will be lower. This is 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.

In its comments on the Draft ASCM ROD, WPAG notes that, as stated by the IOUs, the FERC Form 1 reflects actual income and revenue-related taxes paid. (WPAG, AS20004 at 4.) It would therefore not be difficult to treat taxes consistent with the treatment of other expenses in the ASC calculation. (*Id.*) Taxes actually paid are generally less than taxes allowed based on the marginal tax rate. (*Id.*) As such, BPA's proposed treatment would consistently result in a bias towards a higher ASC for utilities. (*Id.*) BPA respectfully disagrees with WPAG's conclusion that BPA's proposed treatment of Federal income taxes would consistently result in a bias towards a higher ASC for utilities. WPAG did not offer support for its argument that "taxes actually paid are ***generally*** less than taxes allowed based on a marginal tax rate." (Emphasis added.) Federal income taxes paid will vary significantly as the operations of the

Utility vary through time. A Utility may over- or under-recover on its ROE and subsequently its Federal tax liability. This over- and/or under-payment of Federal income taxes relative to the authorized taxes will equilibrate through time.

PPC/NRU argue 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 even assuming that income taxes are 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. Instead, "it is assigned to the BPA Administrator in rate making proceedings to devise a 'methodology' for determining costs." *PacifiCorp*, 795 F.2d at 821. BPA's rationale for determining that Federal income taxes are resource costs has been explained previously.

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 each IOU's rate of return to reflect the Federal after-tax return for ASC determination. This is not a difficult undertaking.

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. (PPC/NRU, ASC0006 at 11.) 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 each IOU's rate of return to reflect the Federal after-tax return. BPA's proposal for inclusion of income taxes completely avoids the need for obtaining expertise in Federal income tax law and accounting and avoids involvement in tracking the tax burden of a resource or group of resources, even assuming that this was required by the Norwest Power Act, which it 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 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 does not find this line of argument persuasive. 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 PPC/NRU's position on this issue because the ASCM does not use actual Federal income taxes paid, but uses the Federal marginal tax rate to gross-up the equity return to reflect the IOUs' after-tax returns. 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 BPA's 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 determinations because it uses the Federal marginal tax rate in a simple gross-up factor 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 decisions 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 include 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 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 would 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).

PPC urges that BPA should continue to exclude Federal income taxes from utilities' ASCs. (PPC, AS20003 at 9.) Federal (and other) income taxes are paid based on the net income of the IOU, which can be positive or negative, and which is only partially affected by the costs of specific generation resources. (*Id.*) BPA disagrees with PPC's simplistic characterization that income taxes paid are based on the net income of the Utility. As noted above, actual taxes paid are also affected by the use of accelerated depreciation for Federal income tax purposes, treatment specifically authorized by an Act of Congress.

PPC also contends that BPA's arguments about "symmetry" with the treatment of ROE are mere "sophistry." (*Id.*) PPC argues that even though an IOU may be allowed an ROE, the IOU might earn no net income and pay no income tax to the Federal government, and yet both the hypothetical ROE and the hypothetical Federal income taxes on the ROE would increase the ASC and thus the subsidy paid by consumer-owned utilities. (*Id.*) In this case, PPC concludes the subsidy would offset completely imaginary costs, not actual costs that would otherwise be borne by residential customers of IOUs. (*Id.*)

Although BPA agrees in part with the PPC on its foregoing comment, the converse can also occur where a Utility earns far in excess of its allowed rate of return, resulting in net income and income taxes far in excess of the amount allowed in ASC. Because there are two sides to this coin, BPA's proposal is reasonable.

PPC claims that BPA has presented no evidence that the gross-up factor "over time will approximate the actual taxes paid by the IOUs." (*Id.*, citing Draft ROD at 93.) PPC argues that BPA's own discussion of the impacts of SB 408 in Oregon belies this conclusion, because Oregon experienced a substantial deviation between *pro forma* tax collections from consumers and actual tax payments to governments. (*Id.*) BPA disagrees because most of the differences in actual and pro-forma taxes can be traced to two items, timing differences between depreciation for book and income tax purposes, and differences between pro-forma and actual returns. BPA discussed earlier in this section, the depreciation issue. Given the numerous examples that PPC cited where utilities could over-earn their allowed rate of return, BPA believes that in those situations, the Utility taxes would be much higher than the pro-forma amount contained in the rate order.

BPA is understandably reluctant to get involved in the calculations of actual tax payments, but cannot rely on *pro forma* results to avoid reality. (*Id.*) Oregon attempted to rely on *pro forma* results and found that it simply did not work, which led to SB 408. (*Id.*) Oregon's direct experience on this issue argues directly against BPA's conclusion. (*Id.*) Thus, the decision to use the gross-up factor is arbitrary and capricious. (*Id.*) BPA disagrees with the PPC on this issue. BPA discussed the timing difference caused by the use of accelerated depreciation for income tax purposes in an earlier part of this section. Moreover, BPA disagrees with PPC's simplistic characterization of the reasons for passage of SB 408 in Oregon. BPA believes the Enron controversy played a much larger role in passage of SB 408 in Oregon. In that case, although Enron did not pay Federal income taxes due total corporate losses, PGE's customers were still charged for taxes PGE's parent, Enron, never paid. BPA believes that the treatment of income taxes between a regulated Utility and its parent are best left to individual state regulatory commissions and state legislators. In the case of Oregon, they saw an abuse and corrected it. This abuse of Oregon Utility regulation by Enron was an isolated event that was solved by the Oregon legislature. BPA does not believe that it is good policy to develop an agency rule incorporating one or more events where an individual Utility or utilities took advantage of the state regulatory system to the disadvantage of its customers.

Finally, PPC asserts that BPA's argument regarding rate stability is "specious." (*Id.*) PPC claims REP payments can be made based on *pro forma* ASC calculations and then later "trued-up" without creating rate instability. (*Id.*) Criticism aside, PPC's suggestion that BPA adopt a "true-up" for taxes is fundamentally unsound. First, there is nothing "specious" with BPA's desire to create rate stability in the implementation of the REP. Indeed, PPC's argument makes little sense given PPC's interests. Under the proposed ASCM, COUs will enjoy greater rate protection under section 7(b)(2) of the Northwest Power Act than in any previous ASCM. *See* 16 U.S.C. § 839e(b)(2). This is because of the unique sequencing of the ASC determinations and the wholesale power rate proceedings under the proposed ASCM. Once ASCs are determined in the review process preceding BPA's power rate cases, BPA will use the resulting ASCs to calculate rates for the following rate period. These ASCs will effectively be set for the rate period, thereby also effectively fixing the costs of the REP recovered in the COUs' rates. The only variables that may change REP costs in BPA's rates are the exchanging Utility's residential loads and pre-determined new resources. This approach to ASC provides COUs far more rate stability and protection than under the previous 1984 ASCM. Under that Methodology, BPA could only *forecast* ASCs when setting rates. The amount of rate protection that the COUs received as a result of the section 7(b)(2) rate test was, therefore, limited to the costs of the REP as determined by *forecasted* ASCs. The actual costs of the REP could, consequently, vary widely once the rate period began because the exchanging utilities could file ASCs that were much different than what was forecasted in the rate case. If these ASCs were higher than what BPA estimated, the end result was higher REP payments and, concomitantly, higher rates for COUs.

PPC's request that BPA add a "true-up" to the ASCM for taxes (and ROE, etc.) harkens back to this less predictable and more volatile approach to ASC. BPA has taken great pains to structure the ASCM in a way that can avoid this uncertainty by limiting the variable components of ASC once the rate period begins. PPC's suggestion would disrupt that construct and insert another unpredictable component that could raise an ASC just as easily as lower it. With the introduction of another indeterminate cost in ASC, the greater the probably that BPA's rates are either over-recovering or under-recovering REP costs. BPA fails to see what policy objective is ultimately achieved by allowing this variability to return to the REP through the ASCM.

Second, as noted previously, BPA has rejected requests from both the IOUs and state commissions to include other "true-ups" to actual costs in ASCs for the same reasons cited above. If BPA were to adopt PPC's proposal on taxes, BPA would necessarily also have to reconsider its refusal to allow the IOUs to true-up other cost categories. The likely outcome of this evaluation is that BPA would have to allow the exchanging utilities to true-up most if not all of their costs within a rate period. This would essentially require BPA to return to a 1984 ASCM form of ASC determinations, with the resulting rate instability for COUs and REP payment variability for exchanging utilities.

Finally, BPA, and the majority of its customers, have purposefully attempted to simplify the REP and the ASCM. One of the major means of simplification was moving away from the "jurisdictional approach" and true-ups to actuals. Using actual Federal income taxes paid to reset ASCs once actual income taxes are known would introduce significant complications. Even though there can be significant variance in actual Federal income taxes paid on an annual basis, BPA does not believe that the use of the authorized Federal income would introduce a significant bias through time. REP payments made based on *pro forma* ASC calculations, and then later trued up, would create rate instability in REP payments due to the deviation from the forecasted rate period ASC and the actual ASC based on changes in Federal income taxes paid.

In their comments on the Draft ROD, the IOUs agree that Federal income taxes are a component of a company's ASC. (IOU, AS20007 at 14; PSE, AS20009_at 16.) However, they believe one important word – "marginal" – has been left out of the decision. (*Id.*) On page 95 of the Draft ROD, BPA argues that its proposed approach reduces the administrative burden "because it uses the Federal marginal tax rate in a simple gross-up factor… that changes only when the Federal marginal tax rate changes." The IOUs therefore recommend that BPA change the Record of Decision to incorporate a marginal tax rate.

(*Id*.) BPA agrees with the IOUs and the marginal tax rate will be referenced.

Decision

The ASCM will include Federal marginal income taxes in ASC. BPA will gross-up the Utility's equity component by the Federal marginal income tax rate when determining an IOU's weighted cost of capital in ASC.

4.8.2 Other Income Taxes

Issue

Whether other state taxes local taxes, and regulatory fees should be included in average system cost.

Parties' Positions

WUTC states that the arguments it raised in support of the inclusion of Federal income taxes also apply to state and Federal revenue-related taxes associated with power supply and transmission. (WUTC, ASC0005 at 22; WUTC, AS20002 at 8.) 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. (*Id.*) 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, AS20007 at 2.) Similarly, 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, ASC0010 at 3; OPUC, AS20010 at 1.) Further, 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 includes only Federal income tax, Federal employment taxes, state property tax on generation and transmission assets, and state unemployment taxes in the determination of ASC.

Evaluation of Positions

Both BPA's 1981 and 1984 ASC Methodologies did not include 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.

1981 ASCM ROD at 13.

In the 1984 ASCM 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.

1984 ASCM ROD at 85.

OPUC argues that state and local taxes are costs of conducting business. (OPUC, AS20010 at 2.) It claims that BPA's current proposal to exclude state and local taxes will frustrate the goal of wholesale rate parity because Utility ASCs 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. (IOU, AS20007 at 3; PSE, AS20009 at 17-18.) 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. (*Id.*) For example, the Public Utility Tax in Washington generally applies to all revenue generated for Utility services provided by IOUs that operate in the state of Washington. (*Id.*) 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. (*Id.*)

The fact that state and local taxes are a cost of doing business does not mean such costs should be included in ASC. As FERC noted in approving BPA's 1984 ASCM:

> 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.

49 Fed. Reg. 39,293, 39,296 (Oct. 5, 1984). The same logic applies here. Also, for example, the Montana Electric Energy Producers Tax for exchanging IOUs is a tax largely paid by customers outside of the state of Montana.

OPUC argues the fact that including state and local taxes will "socialize" these costs to all utilities that exchange under the REP is no reason to exclude the costs from utilities' ASC. (OPUC, ASC0010_at 2.) OPUC knows of no 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. (*Id*. at 3.) As noted above, the fact that a Utility incurs costs does not mean all costs should be included in ASC. BPA disagrees that exclusion of state and other revenue related taxes will frustrate the objective of wholesale rate parity. Wholesale rate parity is achieved by BPA offering the same wholesale power rate (the Priority Firm or PF rate) to preference customers and exchanging utilities, subject to the section 7(b)(2) rate test. Excluding state and local taxes therefore will not affect wholesale rate parity.

OPUC also states that the specter that governments may manipulate tax obligations in order to "game" the REP is not sufficient reason to exclude the costs from ASCM. (*Id.)* In response, BPA notes that under the 1981 ASCM, BPA dealt with a revenue-related state tax seemingly tailor-made for regionalization through the REP. Idaho Power Co. attempted to include in ASC the so-called Idaho "KWH tax." *See* 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 REP. 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 ratepayers outside the taxing jurisdiction is sufficient reason to exclude these costs from ASCM. Therefore, it is BPA's conclusion that state and local taxes are not exchangeable under the ASCM. In their comments on the Draft ASCM ROD, the IOUs state that BPA gives no example of where a state income tax has been gamed. (IOU, AS20007 at 15.) However, regardless of the extent of "gaming" in this area, BPA does not want to provide any incentive for such actions. Furthermore, BPA does not propose to exclude state income taxes because of gaming, but because they would result in a tax shift to other customers in the region.

OPUC states that regulatory fees imposed on a Utility and related to resource costs should be included in the Utility's ASC. (OPUC, AS20011) Under Oregon law, utilities must pay to the OPUC an annual fee to defray the OPUC's costs in performing its statutory obligations. (*Id*.) The fee is a significant cost to utilities operating in Oregon. (*Id*.) 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 Trust activities, carbon regulation, 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 REP issues. (OPUC, ASC0010 at 4). In addition, the IOUs argued for inclusion of several other miscellaneous taxes and fees. (IOU, AS20007 at 2-6.)

BPA does not believe that regulatory fees and other miscellaneous taxes and fees are properly included in ASC. 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.

1981 ASCM ROD at 14. This reasoning is still valid. Under the REP, BPA determines the average system cost of a Utility's resources. Regulatory fees and miscellaneous taxes and fees at the retail level are much farther removed from a Utility's resource costs than costs BPA typically allows in ASC. Also, as noted above, it is not necessary to require payment of every cost an IOU incurs to comply with the Northwest Power Act. *See* 49 Fed. Reg. 39,293, 39,296 (Oct. 5, 1984). Also, as noted above, it is not necessary to require payment of every cost an IOU incurs to comply with the Northwest Power Act. *See* 49 Fed. Reg. 39,293, 39,296 (Oct. 5, 1984).

The IOUs argue that BPA does not acknowledge that regulatory bodies treat Federal and State income taxes in the same manner. (IOU, AS20007 at 15.) In response, although regulatory bodies might treat such taxes in the same manner, this does not dictate the same treatment for ASC purposes. BPA will not include State income taxes in ASC because it results in a shift of the tax to other customers in the region.

PSE cites Out-of-State Property Taxes, *see, e.g*., 2006 FERC Form 1 page 262 and Account 236 and argues that a Utility may pay "out-of-state" state or local property taxes on a particular production or transmission facility (such as on an out-of-state transmission line from a remote generation facility). (*Id*.) PSE argues these fees are appropriately included in ASC and allocated to PROD or TRANS. (*Id*.) For example, PGE pays Washington state property taxes on a natural gas pipeline used to provide natural gas to its Beaver and Port Westward generation facilities, as well as the Mist natural gas storage facility. (*Id*.) PSE argues these fees are appropriately included in ASC and allocated to PROD. (*Id*.) BPA agrees with PSE on the issue of out-of-state property taxes related to a resource or for resource-related costs such as pipelines. Such costs will be allowed if supported and documented.

Decision

The ASCM will exclude state and local income- and revenue-related taxes, excise taxes and miscellaneous fees from ASC, although BPA will include in-state and out-of-state property taxes associated with an exchangeable resource or for resource-related costs such as pipelines.

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 ASCM. 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. (IOU, ASC0004 at 4; IPUC, ASC0003 at 7.)

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.) 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, AS20004 at 2-3.) 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. (WPAG, ASC0008 at 4.)

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 ASCM, 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 ASCM, an exchanging Utility's *entire* transmission investment and expenses were included in ASC. That is, 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 ASCM Decision, at 1-2. FERC granted final approval to the 1981 ASCM 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 ASCM, BPA again allowed transmission costs in ASC. Of particular concern during the consultation process was the belief that exchanging utilities might 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 ASCM, 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 ROD 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 ASCM. In these twenty-four years, the energy industry has seen tremendous changes in both the wholesale power and transmission markets. *See generally* The Changing Structure of the Electric Power Industry 2000: An Update, October 2000, Energy Information Administration, United States Dept. of Energy. 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 IOUs 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 ASCM 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 ASCM that would require BPA to exclude transmission from ASC. (*Id.* at 9.) WUTC also correctly notes that BPA included transmission costs in the 1981 ASCM, 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.) 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.)

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.)* OPUC states these types of decisions should not be influenced by the ASCM. (OPUC, ASC0010 at 6.) 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 ASCM would complicate the ASC determination process is particularly apropos. One key objective of the new ASCM 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 ASCM 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 states that ASCs and the 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.)* 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.) 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 WUTC, including one component (resource costs) but not the other (transmission costs) would likely distort Utility resource decisions. (*Id.*) WUTC concludes that consistency requires that both BPA's costs and the utilities' ASCs include transmission in the same manner and degrees. (*Id.*) WUTC supports including transmission costs in ASC in order to ensure this symmetry. (WUTC, ASC0005 at 11.)

WPAG states 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.) WPAG argues that 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 for 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 ASCM. In any event, however, BPA will not implement the REP in a manner that does not reflect the foregoing symmetry regarding transmissions costs. In its comments on the Draft ROD, WPAG states that the inclusion of transmission costs in the PF Exchange rate is not guaranteed because BPA's PF Exchange rates will be set in future rate proceedings. (WPAG, AS20004 at 2.) In response, BPA notes that whenever transmission costs have been included in ASC, BPA has included transmission costs in the PF Exchange rate. Although WPAG claims the current WP-07 PF Exchange rate does not include transmission costs, review of BPA's WP-07 PF Exchange rate schedule shows this is not true. Also, BPA has not implemented the REP under the current WP-07 PF Exchange rate due to previous REP settlements. Furthermore, the proposed FY 2009 PF Exchange rate in the WP-07 Supplemental Rate Case includes transmission costs.

PPC/NRU do not support BPA's proposal to include transmission costs in ASC. (PPC/NRU, ASC0006 at 4-5.) PPC/NRU finds it noteworthy that in 1984 the IOUs argued that because BPA's rates included both transmission costs and power costs, the ASCM should also allow transmission costs in determining ASCs in deference to "wholesale rate parity." (*Id.*) 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 ASCM, 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 ASCM. The 1984 ASCM 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 ASCM allowed all *new* transmission into ASC provided that it could meet the two criteria described in the 1984 ASCM ROD. *See* 1984 ASC ROD at 42-43. Furthermore, the issue is not whether the IOUs' previous arguments regarding wholesale rate parity are correct. BPA and the IOUs have historically had different understandings of this concept. The issue is whether BPA should include transmission costs in ASC. If transmission costs are included in ASC, such costs should be included in the PF Exchange rate.

PPC/NRU take issue with the observations BPA made in the FRN that described the background for BPA's proposal to include all transmission in the proposed ASCM. (PPC/NRU, ASC0006 at 5-6.) As noted above, BPA explained in the FRN 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 ASCM, so their presence does not justify changes now. (PPC/NRU, ASC0006 at 5.) BPA assumes PPC inadvertently made the foregoing statement. Due to the *enormous* changes in the wholesale power markets between 1980 and 2008, one cannot reasonably equate the existence of the 1980 wholesale power markets with the highly evolved 2008 wholesale power markets. Also, PPC/NRU appear to misunderstand the relevance of the changes that the wholesale power markets have on the calculation of a Utility's ASC. BPA did not say in its FRN that the mere "existence" of wholesale power markets made changes to the ASCM 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 understands 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 ASCM. 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 argue 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 FRN 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 ASCM, 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 ASCM 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. *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. (*See* IPUC, ASC0003 at 6; OPUC, ASC0010 at 6; IOUs, ASC0004 at 9-10.) As noted earlier, BPA finds these arguments persuasive. 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 argue 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 might 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, utilities invest 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 conclude 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 ASCM 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. 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 FRN warrant returning to BPA's original position of allowing all transmission costs in ASC.

Moreover, PPC/NRU's comments do not support their conclusion that all transmission costs be excluded from ASC. PPC/NRU note throughout their comments that nothing significant has "changed" since 1984 that would warrant a change in the ASCM as BPA has proposed. Assuming *arguendo* that PPC/NRU were correct (which it is not), it then follows that BPA should remain with its previous treatment of transmission under the 1984 ASCM. 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.

PPC disagrees with BPA's proposal to include transmission costs in ASC and to include "symmetrical" transmission costs in the PF-Exchange rate. (PPC, AS20003 at 10.) PPC argues that "two wrongs do not make a right." (*Id*.) The actual (or projected) transmission costs incurred by IOUs in making resource choices will almost certainly vary from Utility to Utility. (*Id*.) Thus, discovering or constructing "symmetrical" transmission costs to add to the PF Exchange rate will be an exercise in frustration. (*Id*.) PPC claims that a new and detailed methodology just for this purpose will have to be developed. (*Id*.) PPC also asserts that it would be far simpler to just exclude transmission costs from both the ASC and the PF Exchange rate. (*Id*.) PPC notes that BPA argued in the Draft ROD that purchased power sometimes is bundled with transmission service, thus making it difficult to unbundle transmission costs so they can be subtracted from ASC. (*Id*.) PPC, however, counters that it would be far simpler to assume a generic transmission cost for purchased power, and subtract that when required, than to build a "symmetric" transmission cost to be added to the PF Exchange rate. (*Id*.)

PPC, once again, appears to misunderstand both BPA's proposal and the historical operation of the REP. First, PPC's claim that including transmission costs in ASC and in the PF Exchange causes BPA to commit "two wrongs" is fallacious. Under the traditional implementation of the REP, BPA has *always* included transmission costs in the PF Exchange rate because the ASCM has *always* allowed transmission costs into ASC. As noted above, the 1981 ASCM, based on a general consensus of BPA's customers and interested parties, allowed all transmission plant and expenses into ASC. *See* 1981

ASCM ROD at 7. The 1984 ASCM also allowed all transmission costs into ASC associated with transmission facilities built before July 1, 1984, and all subsequent transmission that could meet the criteria described in the 1984 ASCM ROD. *See* 1984 ASCM ROD at 42-43. Throughout the term of both of these Methodologies, BPA consistently included in the PF Exchange rate the cost of transmission in order to maintain an "apples-to-apples" comparison with the Utility's ASC. PPC's assertion that BPA is committing two "wrongs" by maintaining this historic congruity between the PF Exchange rate and the ASC in the proposed ASCM is simply incorrect, as demonstrated by preference customers' support of including transmission costs in the 1981 ASCM.

PPC also remarks that the "actual (or projected) transmission costs incurred by IOUs in making resource choices will almost certainly vary from Utility to Utility. Thus, discovering or constructing 'symmetrical' transmission costs to add to the PF Exchange rate will be an exercise in frustration." (PPC, AS20003 at 10.) PPC contends that to make this proposal work, BPA will have to develop a "new and detailed methodology just for this purpose. . ." *Id*. PPC's comment misconstrues what BPA meant by "symmetrical" transmission costs. When using the phrase "symmetrical transmission costs," BPA meant the same "type" or "kind" of transmission costs should be included in the PF Exchange rate. In this context, BPA does not believe it will be unduly difficult to determine what types of costs must go into the PF Exchange rate to create symmetry with the ASC determinations. For example, under the proposed ASCM, exchanging utilities will be allowed to exchange their entire "transmission plant" with BPA. Transmission plant, for the most part, is comprised of costs that are included in the Utility's integrated network transmission system and resource integration. To "match" this transmission component in the Utility's ASC, all BPA has to do is add its own Network Transmission rate to the PF Exchange rate because the PF Exchange rate already includes BPA's resource integration costs. BPA's Network Transmission plus resource integration costs included in the PF Exchange rate, like the exchanging Utility's network rates plus their resource integration, include the same "types" of transmission costs that exchanging utilities include in their Transmission Plant account.

PPC appears to have interpreted the phrase "symmetrical transmission cost" to mean the same *amount* of transmission costs; that is, BPA must include in its PF Exchange rate the same amount of transmission costs that the exchanging utilities include in their ASCs. If that is what PPC is suggesting, its comment is misplaced. BPA has never required a Utility to include the same amount of costs for purposes of determining an ASC that BPA includes in its PF Exchange rate. Every exchanging Utility's resource costs are going to be, on a gross level, different than what BPA includes in its PF Exchange rate. The ASC calculation is a Utility by Utility determination. The ASC is determined by dividing the Utility's total cost of resources (referred to as Contract System Cost) by the Utility's total system load (referred to as the Contract System Load). The quotient of this calculation is compared to BPA's PF Exchange rate, which is established in accordance with section 7(b) of the Northwest Power Act. Nowhere in this construct would it be appropriate to compare the actual costs BPA pays for resources with the actual costs of resources paid by the Utility. In any case, BPA is not proposing to include the same "amount" of transmission costs in the PF Exchange rate as is included by the Utility in its ASC. As such, PPC is operating from a misunderstanding of BPA's proposal when it comments that BPA will have to develop a "detailed methodology" just for the purposes of determining the "symmetrical transmission costs." (PPC, AS20003 at 10.)

PPC concludes that the simpler approach would be to remove transmission costs from the ASCM and the PF Exchange rate. (PPC, AS20003 at 10-11.) To deal with power purchases that have embedded or "bundled" transmission costs within them, PPC suggests BPA assume a "generic transmission cost for purchased power, and subtract that when required, [rather] than to build a 'symmetrical' transmission cost to be added to the PF Exchange rate." (*Id*.) BPA, however, disagrees that PPC's suggested approach is any simpler than BPA's proposal to include all transmission costs. Indeed, PPC's approach would be much more difficult to implement. Deducting every purchase power contract for a "generic transmission cost for purchase power" would require an extremely difficult and contentious process. BPA cannot conceive of how such a generic figure could be calculated, or what factual or legal foundation BPA would use to support a generic deduction for unknowable transmission costs from a Utility's ASC. Even if BPA could adopt this recommendation, BPA foresees that such an approach would quickly descend into an administrative quagmire. Understandably, exchanging utilities would want to provide evidence that this adjustment should not be made to their ASC because the cost of their resources does not include transmission costs. This would inevitably require BPA to review the terms, conditions, and circumstances surrounding each of the Utility's power purchases to ensure that a Utility is not surreptitiously including the cost of transmission. The administrative burden of conducting these types of reviews for every purchase power agreement a Utility intends to exchange with BPA vastly outweighs any disadvantage of simply adding BPA's own network transmission costs to the PF Exchange rate.

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; WPAG, AS20004 at 2-3.) 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 ASCM 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 asks 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 the generation integration function exclusively and transmission used for other purposes. (WPAG, ASC0008 at 3; WPAG, AS20004 at 2-3.) 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, while including transmission costs in the PF Exchange rate.

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; WPAG, AS20004 at 2-3.) 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 ASCM 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.

In its comments on the Draft ASCM ROD, WPAG states that although duplicative construction may no longer be an issue as it was in 1984, other uses of transmission for purposes other than generation integration still exist, such as the functionalization of high voltage distribution lines as transmission. (WPAG, AS20004 at 3.) WPAG also states that BPA's argument that the inclusion of revenue credits from transmission used for other purposes "tend to neutralize most if not all of the costs" is not justifiable. (*Id.*) WPAG's arguments are once again unconvincing. First, WPAG's comment erroneously assumes that a difference must be made between transmission used for "generation integration" and general transmission plant costs. In fact, BPA is not required by the Northwest Power Act to make that distinction. Section 5(c)(7)(A)-(C) of the of the Northwest Power Act states the only statutory limitations on BPA's discretion to establish a methodology that determines a Utility's average cost of resources. *See* 16 U.S.C. § 839c(c)(7)(A)-(C). Nothing in these sections speaks to excluding all transmission costs except generation integration. Indeed, prior to the 1984 ASCM, BPA included the entire cost of a Utility's transmission plant in ASC, as agreed to by the parties to the 1981 consultation, which included both preference customers and IOUs. *See* 1981 ASCM at 7. Thus, BPA properly includes the cost of transmission costs, not just generation integration, in ASC.

Second, WPAG fails to articulate any reason why BPA must maintain the 1984 ASCM compromise, which limited future transmission costs to only generation integration. As noted above, this feature of the 1984 ASCM was a product of a compromise that was specifically created to deal with the unique circumstances raised in the 1984 consultation process. As BPA explained earlier, those concerns generally do not exist today. Even more, readopting the 1984 compromise into this ASCM would create more problems than it solves because it would reintroduce a Goldbergian level of complexity into ASC determinations. Under the 1984 ASCM compromise, BPA would be required to "date stamp" all of the exchanging Utility's transmission facilities that existed prior to July 1, 1984. Although the Utility would have the initial burden of making this determination, BPA would still have to review the Utility's data to ensure that only the pre-1984 transmission facilities were included in ASC. This would mean BPA would have to keep track of every piece of transmission plant that existed prior to July 1, 1984, for each exchanging Utility. The difficulties of monitoring the Utility's aging transmission system will only become more time-consuming and burdensome as the Utility begins to replace transmission facilities. BPA will then have to make complicated decisions on issues such as whether the costs of repairing old facilities with new parts is exchangeable or whether upgrading a single component of a larger transmission facility constitutes a complete replacement. The administrative burden this approach would impose on BPA and the ASC Review Process alone militates against retaining the 1984 compromise in the current ASCM.

Even assuming that such a review was reasonable, additional problems would emerge as the parties and BPA try to define what transmission costs constitute "generation integration" costs. As noted earlier, the term "generation integration" is amorphous, and can mean any one of a number of types of transmission facilities. It could mean as little as a generation step-up transformer or fifty miles of a radial transmission line. In either case, BPA would have to evaluate every transmission facility connected to the Utility's generation resources and make an independent determination as to whether the facility meets BPA's definition of generation integration.

Finally, even assuming that BPA could keep track of the 1984 transmission facilities, and could define and track a Utility's transmission costs that were used to "integrate generation", BPA's would still not know whether the transmission cost is exchangeable. Under the 1984 ASCM compromise, transmission plant costs for post-1984 facilities are only allowed into the ASC if they are used for generation integration *and* are less than the "sum of the costs of the transmission facilities required to integrate the generation resource to the BPA system and the wheeling costs necessary to wheel the power to the exchanging Utility's system." *See* 1984 ASCM at 17 n.a(2). Consequently, BPA would need to conduct further analysis to determine the cost of building a transmission line from the Utility's resources to BPA's transmission system, add in the cost of wheeling the power over BPA's system to the Utility, and then compare the results with the cost the Utility wishes to exchange with BPA. The administrative burden this last requirement would impose on BPA and the ASC review process would be massive. BPA would have to expand its ASC staff to include consultants and engineers to assist in estimating the costs of building a transmission line from the Utility's resources to BPA's system. Only after completing this last step could BPA determine the Utility's ASC. BPA fails to see the need to add all of these arduous tasks to the ASC review process in order to determine transmission costs. As WPAG readily admits, the concern over duplicative transmission construction, which led to these provisions in the 1984 ASCM, is largely gone today. (WPAG, AS20004 at 3.) Rather than revert back to these arcane distinctions in the 1984 ASCM, BPA believes the better and more reasonable approach is to allow all transmission costs in ASC as proposed in the new ASCM.

WPAG's concern that high voltage distribution lines would be functionalized to transmission would exist regardless of whether BPA adopted the generation integration distinction. The state Utility commissions and FERC largely regulate how a Utility accounts for transmission costs in its various regulatory filings. WPAG's concern that distribution costs could be inappropriately included in transmission should be corrected by the FERC account requirements that limit the types of transmission costs that can be included in transmission plant accounts versus the distribution plant accounts.

WPAG also states that BPA's argument that the inclusion of revenue credits from transmission used for other purposes "tends to neutralize most if not all of the costs" is not "justifiable." (*Id.*) Why, exactly, BPA's position is not justified is not explained. As noted earlier, all of the revenue associated with the other uses of a Utility's transmission facilities will be used to credit against the cost of transmission in ASC. Thus, if a Utility builds a transmission line and sells 30% of the use of the line for non-load service, the revenue the Utility receives for those sales would be credited against the cost of the transmission facilities. The end result is that the Utility will only be exchanging with BPA the cost of the transmission line that was used to serve the Utility's loads. This will be generally true of any transmission plant that is used for multiple purposes. Thus, BPA's proposal is not violating any aspect of the Northwest Power Act by allowing all transmission costs into ASC. Furthermore, this approach is reasonable, simple, straightforward, and very practical to administer. Finally, neither WPAG, nor any other party has articulated a reason why it should be abandoned.

WPAG also argues that if all transmission costs are permitted to be included in ASC by IOUs, then other transmission costs incurred by COUs in addition to the transmission costs to be included in the PF Exchange rate must be considered as well. (WPAG, AS20004 at 3.) BPA understands this comment to mean that if all transmission costs are permitted to be included in ASC by exchanging utilities, then additional transmission costs incurred by COUs, in addition to the transmission costs to be included in the PF Exchange rate, must be considered as well.

BPA does not agree that it must consider the cost of transmission to its power customers if it intends to allow all transmission costs into ASC. First, as already noted, BPA cannot determine in this proceeding what transmission costs would be or would not be appropriate in the PF Exchange rate. As noted above, those matters must be addressed in a section 7(i) proceeding. However, as a general a legal matter, BPA notes that WPAG's suggestion would not be consistent with the law. The REP is designed to compare BPA's PF Exchange rate with a Utility's cost of resources. The PF Exchange rate is a BPA rate, and as such, must be developed in accordance with section 7 of the Northwest Power Act. *See* H.R. REP. NO. 96-976, pt. I, at 60 (1980) ("Average system cost is established pursuant to section 5(c)(7) and the rates for resale are established under section 7(b)(1).") The Act is explicit that BPA's rates must be designed to recover the costs "incurred by the Administrator…" 16 U.S.C. § 839e(a)(1). These rate directives are clear that BPA sets its rates to recover the costs that *BPA* incurs. The Act makes no allowance for BPA to set rates to recover the costs that BPA's *customers* incur. Yet, that is what WPAG appears to be suggesting in its comment. WPAG asks BPA to set the PF Exchange rate to include not only BPA's transmission costs, but also the "additional transmission costs incurred by COUs." BPA has no authority under the Northwest Power Act, or any other law, to set rates to recover the transmission costs of the COUs. BPA can only set its rates to recover the costs "incurred by the Administrator[.]" *Id.* Consequently, WPAG's suggestion is contrary to law.

Second, even if WPAG's suggestion did not violate the cost mandates of section 7 of the Northwest Power Act, other problems with WPAG's recommendation make it logically unsound. The construct of the REP has always been to compare BPA's costs as expressed in the PF Exchange rate with the Utility's costs as expressed in an ASC. These rates were chosen in order to allow the region's "IOUs to share in the economic benefits of the lower-cost Federal resources marketed by BPA and will provide these consumers wholesale rate parity with residential consumers of preference utilities in the region." H.R. REP. NO. 96-976, pt. II, at 35 (1980). Changing this construct to now include the COU's costs in the PF Exchange undermines the Congressionally intended design of the REP. Instead of comparing the "lower-cost Federal resources", BPA would be comparing a melded preference customer cost of resources with the Utility's ASCs. BPA finds nothing in the legislative history of the Northwest Power Act that suggests that Congress intended to achieve "wholesale rate parity" through the Residential Exchange Program in this manner. The clear intended operation of the REP is to pay benefits based on a "rate identical to what preference customers pay BPA for power to meet their 'general requirements' . . ." *Id.* BPA, therefore, rejects WPAG's suggestion that BPA depart from the clear Congressional direction on how the REP is supposed to be operated and include transmission costs not incurred by BPA (and not charged to preference customers).

Finally, BPA sees many practical problems with WPAG's suggestion. Though not exactly clear, WPAG's approach would appear to require BPA to include in its PF Exchange rate the costs that COUs incur for transmission. Simply obtaining this information from all of the COUs would be extremely burdensome. There are over a hundred COUs that are served by BPA. Many of these customers purchase transmission not only from BPA, but also from a number of other transmission providers. As such, there would be likely variations in the transmission costs each COU incurs to serve its load. BPA would need to establish specific procedures and mechanisms to get the information from these customers, and then develop a specific methodology for translating those costs into a usable form for purposes of its rates. BPA fails to see, and WPAG does not explain, why all of these steps, and additional steps, would be necessary if BPA intends to include all transmission costs in ASC.

In its comments on the Draft ROD, Snohomish states that BPA should commit to adjust the ASCM to include or exclude the same costs as may be included or excluded in the PF Exchange rate, ensuring the comparison of the PF Exchange rate and the Utility's ASC is "apples to apples." (Snohomish, AS20006 at 2.) As a practical matter, when BPA establishes an ASCM, it is expected to be used to implement the REP for a significant period of time. Although BPA may amend the ASCM in order to address specific problems arising with its implementation, it is not subject to change with the frequency of BPA's power rates. Thus, it is more likely that BPA would address any alleged asymmetry regarding ASCs and BPA's PF Exchange rate in the establishment of the PF Exchange rate in BPA's power rate proceedings.

Decision

The ASCM will include all transmission costs in ASC. BPA will also propose and support in its rate proceedings to include "symmetrical" transmission costs in the 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 ASCM that requires COUs to submit a detailed Cost of Service Analysis (COSA) prepared by an accounting or consulting 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 there is no comparable requirement for IOUs. (*Id.*) PPC claims there is sufficient review of COU cost of service analyses already. (PPC, AS20003 at 11.)

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 were materially correct and reasonable projections of their costs of operations that will be collected in rates charged to 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 ASCM.

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 independent 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 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 ASCM.

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 ASCM 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.

In its comments on the Draft ROD, Snohomish states that virtually all COUs have an independent auditor whose sole purpose is to provide oversight to the financial documentation and rate setting process, and reports directly to the governing board. (Snohomish, AS20006 at 1-2.) Also, the governing board is an independently elected group that reviews and approves Utility rates and budgets, providing oversight similar to the state Utility commission. (*Id.*) Snohomish claims a contract with an independent accounting or consulting firm would consist of duplicative costs and redundancy. (*Id.*) In response, BPA acknowledges that this requirement could result in some costs to exchanging COUs. Nevertheless, the Utility's residential consumers receive significant benefits from the REP. BPA believes the incurrence of costs to verify information that makes REP benefits possible is a reasonable administrative burden. However, BPA does not wish to require unnecessary duplication of effort. Therefore, if a COU already has an independent auditor that prepares financial documentation for the Utility's rate setting process and, in addition to such expertise, also has demonstrated expertise and experience with developing cost of service analyses, the COU can use the same entity to review and verify that the COSA submitted by the COU is a materially correct and reasonable projection of its costs of operations going forward that will be collected in the rates charged retail customers. BPA will require such entities to demonstrate their experience with cost of service analyses prior to accepting such entity's verification.

PPC also disagrees with the proposal that exchanging consumer-owned utilities should be required to file COSA tables that have been either prepared or reviewed by an independent accounting or consulting firm. (PPC, AS20003 at 11.) Consumer-owned utilities cannot set rates in a vacuum, and must, under normal circumstances, borrow funds from time to time. (*Id.*) Consumer-owned utilities must also meet auditing standards, both to comply with state law and to meet the requirements of financial markets. (*Id.*) Thus, there is sufficient review of COU cost-of-service analyses already. (*Id.*) BPA acknowledges that many COUs will likely have engaged an independent accounting or consulting firm to review their financial information to conform to state law or lending requirements. It is for that very reason, though, that BPA believes the COUs should be able to obtain the necessary certification without difficulty. As noted above, without this requirement BPA would have no way of knowing whether the COSAs submitted by the COUs are materially correct and reasonable projections of their costs of operations that will be collected in the rates charged retail customers. PPC suggests that BPA just rely on the financial data that serves as the basis for a COU's rates because such data must meet "auditing standards … to comply with state law and to meet the requirements of financial markets." The problem with this approach is that there is no one applicable standard or certification that can be relied upon to assuage BPA's concern with the validity of a COU's data. Different lending institutions will likely have differing levels of review, as will state law auditing requirements. BPA considers its approach the better option because it creates uniformity across the COU customer class, much in the same way that FERC requires the IOUs to provide certifications for their FERC Form 1s. Again, COUs using independent accounting or consulting firms to review their financial information may have the same firms review their COSA upon a demonstration to BPA of the firm's experience developing cost of service analyses. BPA hopes this helps to minimize any additional costs incurred by the COU.

Decision

The ASCM 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 argue that ASC should not include an 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 proposed Methodology provides that 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 IOUs' FERC Form 1 filings in the weighted cost of capital section of the ASCM. PPC/NRU argue 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 recommend that the ASCM 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 ASCM should replace the IOUs' cost of debt with BPA's cost of debt. The REP does not affect or encourage incremental the risk-taking behavior of the IOUs because REP benefits flow directly through to the IOUs' residential and small farm customers and do not affect IOU profits. In addition, it would be inappropriate to equate IOUs' costs of debt with BPA's cost of debt. Unlike the IOUs, BPA is able to finance resources without issuing common equity and can obtain Treasury bonds or government-secured debt.

PPC disagrees with BPA's rejection of the proposal to adjust the IOUs' cost of debt to eliminate the effects of risky investments. (PPC, AS20003 at 11.) The silence of the Northwest Power Act on this issue is similar to statutory silence on other issues. (*Id*.) It is within BPA's discretion to decide not to require consumer-owned utilities to subsidize risky investments by IOUs. (*Id*.) BPA disagrees. As noted above, REP payments flow through directly to eligible residential and small farm customers of the IOUs. They do not increase or decrease profits for exchanging utilities. If REP benefits do not affect profits, then they cannot encourage or discourage "risky investments" because REP benefits will not affect the after-tax return on investment (ROI) of such "risky investments."

In their comments on the Draft ROD, the IOUs believe the cost of debt used in the weighted cost of capital section of the ASCM should be the IOU's most recent regulatory approved cost of debt. (IOU, AS20007 at 16; PSE, AS20009 at 19.) The weighted cost of debt is determined for each IOU by the state regulatory commission as part of the capital structure and overall rate of return and is consistent with BPA's decision on the return on equity. (*Id*.) The IOU would include the weighted cost of capital from its most recent rate order. (*Id*.) IOUs with service territories in more than one state would submit a weighted cost of capital based on the most recent regulatory rate orders weighted by rate base in states within the Pacific Northwest region. (*Id*.) BPA agrees. BPA will use the cost of debt contained in the weighted cost of capital section of the Utility's most recent state commission rate order in the Rate of Return section of the ASC Template.

Decision

The ASCM will use the cost of debt contained in the weighted cost of capital section of the Utility's most recent state commission rate order in the Rate of Return section of the ASC Template.

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 state 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.)

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 expenditures are required to provide services and the time collections are received for such services.

See G. Hahne and G. Aliff, Public Utility Accounting , at 5-4 (Mathew Binder 2005). Because the 1981 and 1984 ASC Methodologies relied on a jurisdictional approach, CWC was a part of Utilities' rate base calculations 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 ASCM 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 separately 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 ASCM.

WUTC supports BPA's treatment of CWC in the ASC determinations. (WUTC, ASC0005 at 23-24.) The WUTC states that the method proposed used 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 argue that this proposal, although a continuation of the 1984 ASCM, 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 ASCM 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 issue. PPC/NRU misinterpret 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 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.

PPC argues that if BPA includes CWC associated with transmission in the ASCM, then by "symmetry" CWC associated with transmission must be included in the PF Exchange rate. (PPC, AS20003 at 11.) BPA does not include CWC as part of its revenue requirement; however, BPA does include an amount for liquidity needs. This amount is similar to the CWC requirements for IOUs. Adding a CWC component to the transmission revenue requirement would be tantamount to double counting. In addition, although BPA can establish the provisions of the ASCM in a consultation proceeding, BPA cannot address issues regarding the development of the PF Exchange rate in such a proceeding. BPA can only establish the PF Exchange rate in a formal evidentiary hearing as prescribed by section 7(i) of the Northwest Power Act. 16 U.S.C. § 839e(i). BPA will address PF Exchange rate issues in BPA's section 7(i) rate proceedings.

Decision

The ASCM 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 state 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 suggest 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 ASCM, 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 note 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 assert that functionalization of the RALs is not the only issue, although it is important. (*Id.)* PPC/NRU are 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 ASCM create such incentives. (*Id.)* Thus, PPC/NRU recommend that BPA retain the ability to exclude RALs, based on direct analysis. (*Id.)*

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.*) 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, 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 with the observations PPC/NRU and 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 ASCM, 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

The ASCM 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 initial 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 Expedited 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 would start billing BPA for actual exchange loads under the 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.

In their comments on the Draft ROD, the IOUs believe a "current" distribution loss study should include the Utilities' most recent loss study. (IOU, AS20007 at 17.) They state system losses are relatively stable over time, and unless significant investment has been made to reduce losses, a Utility's most-recent study should accurately describe losses on its system. (*Id.*) The IOUs also advocate that where a Utility has the capability to directly measure distribution losses on its entire system, that information must be used in lieu of a distribution loss study to reflect the Utility's system losses. (*Id.*)

BPA agrees in part with the IOUs on this issue. If the Utilities have sufficient revenue grade meters in their distribution system, BPA will permit those utilities to directly measure their distribution losses subject to BPA review and approval. Utilities that do not possess the capability to directly measure their distribution losses will be required to submit a distribution loss study every seven years, or use the default loss calculation specified by BPA below.

The IOUs state that as an alternative to having a distribution loss study, or access to direct measurements of losses, they support BPA's proposed method to determine their respective distribution loss factors, with the exception that a Utility should subtract the transmission loss factor for its own transmission system, instead of the proposed method of subtracting BPA's transmission system loss factor. (IOU, AS20007 at 17; PSE, AS20009 at 20.) In the event an IOU does not have a loss factor for its own transmission system, then it could be directed to use BPA's transmission system loss factor as a default. (*Id.*) BPA disagrees with the IOUs concerning use of their own transmission system loss factor in place of BPA's system loss factor. The goal of requiring a distribution loss study is to obtain an accurate estimate of distribution losses for use in the ASC calculation. BPA believes that the best way to get accurate estimates of distribution losses is through a formal distribution loss study, prepared every seven years, or through direct measurement for utilities that have the technology available to perform such measurement.

PSE argues the ASCM should be clarified to indicate that -- because loss factors only change slowly over time and because it typically takes a fundamental change in the configuration of a Utility's system to cause a significant change in the loss factor -- a study is current in the absence of a fundamental change in the configuration of a Utility's system. (PSE, AS20009 at 20.) BPA agrees with PSE on this issue and will require a formal loss study every seven years for those Utilities that do not have the capability to directly measure distribution losses.

Decision

The ASCM will allow participating Utilities that have the ability to directly measure distribution losses on their system to submit such measurements, subject to BPA review and approval, with their ASC filings.

Utilities that do not possess the capability to directly measure distribution losses on their system will be required to submit a formal distribution loss study with their ASC filing. The distribution loss study will be valid for a period of seven years

Utilities that do not have the ability to directly measure distribution losses on their system and do not have a formal distribution loss study that was prepared within the previous seven years of the date of the ASC filing will use the default distribution loss study method described below.

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.*

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 acknowledging 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 ASCM." 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 in 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 20 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 done 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>

The ASCM 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>

<u>Issue</u>

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 courts 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 ASCM was not founded on responding to industry trends, the proposed ASCM 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 utilities' costs. This is much different, however, than founding an ASCM on such trends.

Decision

The ASCM 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 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 ASCM does not address this problem, and so is deficient. (*Id.*) Any revisions to the ASCM 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 ASCM. The proposed ASCM contains provisions to address the adoption of tiered rates. BPA can always revise the ASCM 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 ASCM does not address this problem, and so is deficient. (*Id.*) Any revisions to the ASCM 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 ASCM at this time be modest and temporary. (*Id.*)

PPC/NRU raise 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 time, due to the very significant uncertainty in how customers will meet load growth and what the actual effects on REP benefits will be, BPA does not believe it is necessary to address this issue. 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, they can be addressed in BPA's design of the PF rates and, if appropriate, the Administrator can start a consultation proceeding to revise the ASCM.

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 ASCM ready to implement the REP. The 1984 ASCM 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 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 ASCM interacts with BPA's tiered rate development can be changed. The proposed ASCM contains provisions under which customers can ask the Administrator to revisit the ASCM. Thus, significant changes can be made to the ASCM for a myriad of reasons, but BPA can later revise the ASCM to address any problems with its implementation.

PPC states that despite BPA's assertion, the ASCM does not properly reflect the existence of tiered rates. (PPC, AS20003 at 12.) BPA's proposal that the ASCM can be revisited "[i]f implementation issues associated with interactions between Tiered rates and the ASCM become more apparent and real" is inadequate. (*Id*., citing Draft ROD at 123.) PPC recognizes that the Methodology is subject to a new consultation proceeding, but such accommodation is at the Administrator's discretion. (*Id*.) PPC suggests that rather than waiting to determine if the adoption of tiered rates causes a disconnect between the proposed ASCM and Congressional intent, BPA should state that the design of the PF Exchange rate *will* reflect changes in incremental reliance on BPA by preference customers to meet load growth. (*Id*.) PPC states that to the extent that *any* load growth is met by preference customers in lieu of purchases from BPA due to tiered rates, the PF Exchange rate, the ASCM, or both, must change. (*Id*.) Otherwise, PPC claims, the intent of the Northwest Power Act will be thwarted. (*Id*.)

Although a new consultation proceeding is at the Administrator's discretion, BPA has an interest in ensuring that BPA's tiered rates are implemented in a manner that does not conflict with the 2008 ASCM, and vice versa. As noted previously, however, it is premature to address the manner in which this will occur. Although PPC advocates an early statement of principle on this issue, BPA believes that it should establish such principles at the time when BPA is well informed by the facts. Although BPA will not state this principle now, PPC will have the opportunity to raise this issue again at the appropriate time.

Finally, BPA does not agree that it must commit at this point to either modifying the PF Exchange rate or the ASCM in any particular fashion to "properly reflect the existence of tiered rates." (PPC, AS20003 at 12.) How and whether to modify the ASCM (or PF Exchange rate) to address concerns with tiered rates will best be determined when faced with live issues in the implementation of the REP. Committing now to make certain changes to the PF Exchange rate or the ASCM incorrectly assumes that the parties to this proceeding have sufficient foresight as to what adjustments will best resolve the issues that may arise with tiered rates in the future. BPA believes that the more reasonable approach is to address those concerns once they become more apparent and real.

Decision

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 the ASCM's design of the PF rates and, if appropriate, the Administrator can start a new limited consultation proceeding to revise the ASCM.

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 ASCM unequivocally do not replicate the benefits provided the IOUs under the 2000 REP Settlement Agreements. BPA is proposing to change a 1984 ASCM 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 ASCM 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 ASCM 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 ASCM and/or BPA's implementation of the section 7(b)(2) rate test. BPA did not need to resolve the ASCM issues because the REP Settlement Agreements rendered such issues moot. 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 Agreements have been held unlawful, WPAG feigns surprise when BPA revisits the ASCM and must revisit the dormant issues critical to proper implementation of the REP. All parties recognized that the 2000 REP Settlement Agreements left significant REP issues unresolved which, when resolved, could significantly increase or decrease REP benefits. 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 ASCM and ratemaking decisions because neither administrative process has been completed. In particular, the section 7(b)(2) rate test is expected to significantly limit the level of prospective REP benefits. 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. 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 ASCM.

Decision

The ASCM's changes 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 ASCM 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 ASCM 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 ASCM 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.*) Although PPC/NRU 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 ASCM. (*Id.*)

BPA agrees that a properly functioning section 7(b)(2) rate test should not serve as an excuse for adopting a flawed ASCM. Indeed, BPA's development of the proposed ASCM 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 facts that the REP has not been implemented for *10 years*; the existing ASCM is *24 years old*; the electric Utility industry has undergone radical changes since 1984; the Court that reviewed the previous ASCM and did not sanction a permanent exclusion of certain costs; and that very real concerns have been raised regarding the continuing legitimacy of the changes made in the 1984 ASCM. BPA is revising the ASCM 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 bear 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. Indeed, the Northwest Power Act prescribes that preference customers will pay certain costs of the REP, subject to the section 7(b)(2) rate test. At the same time, the Act permits IOUs to receive REP benefits based on a Utility's ASC and

BPA's PF Exchange rate. BPA must follow the law and cannot artificially suppress the proper development and implementation of the ASCM in order to benefit adjacent preference customers.

PPC disagrees with BPA's conclusions regarding whether BPA's proposed Methodology will lead to overly generous ASC determinations. (PPC, AS20003 at 13.) PPC claims the proposed ASCM may well lead to anomalous results, including subsidies paid by higher-rate residential consumers of consumer-owned utilities to neighboring lower-rate residential consumers of IOUs. (*Id*.) The fact that the ASCM has not been changed in 24 years does not and cannot eliminate this possibility. (*Id*.) PPC has misinterpreted BPA's position. First, the issue of whether benefits provided to preference customers and IOUs under the REP are "overly generous" is subjective. Exchanging utilities may believe REP benefits are too low, while non-exchanging utilities may believe REP benefits are too high. However, BPA believes REP benefits will not be "overly generous" if they are determined in accordance with a properly established ASCM and a properly established PF Exchange rate. BPA has carefully reviewed the issues parties have raised in this proceeding regarding the ASCM and has worked hard to ensure that such issues have been resolved in accordance with the Northwest Power Act. Therefore, the ASCM will not provide "overly generous" benefits, it will provide benefits as directed by the Act.

Further, PPC argues that BPA's assertion that the REP has not been implemented for 12 years is simply contrary to fact. (*Id*.) PPC states that had there been no REP, there would have been no payments by BPA to regional IOUs, and yet such payments have in fact continued for this entire period, under Congressional mandate and illegal "settlement agreements." (*Id*.) BPA believes PPC has a different understanding than BPA of the phrase "implementation of the REP." The REP is implemented through Residential Purchase and Sale Agreements, which are contracts between BPA and each exchanging Utility. If BPA does not have RPSAs in effect, BPA cannot implement the REP. Between 1993 and 1998, the IOUs executed REP settlements with BPA. The settlements terminated the exchanging utilities' RPSAs. Therefore, there were no RPSAs in effect between BPA and regional utilities (except for Montana Power Company, which was in deemer status) after the respective settlements were executed between 1993 and 1998. Thus, there was a period of 10 to 15 years in which the REP was simply not implemented for those utilities. In addition to RPSAs, the REP is implemented through utilities filing proposed ASCs with BPA; BPA conducting a public review proceeding to establish each ASC; and with BPA's final ASC determinations for IOUs being submitted to FERC for review and approval. From the dates of the respective 1993-1998 REP settlements to the present, no utilities filed proposed ASCs with BPA; BPA conducted no ASC review proceedings; and no ASC determinations were filed with FERC for approval. Thus, the REP was not implemented for the respective utilities during that period.[9] Although the 2000 REP Settlement Agreements settled disputes arising under the REP, they did not implement the REP.

Decision

The ASCM complies with the Northwest Power Act and provides only such REP benefits as are proper under the law.

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[9] For one fiscal year (FY 1997), Congress established the level of REP benefits. Because Congress established the REP benefit level, BPA did not have to implement the REP.

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 properly justified its proposed changes to the 1984 ASCM, and BPA received additional comments regarding the proposed changes that have supplemented the record in this proceeding.

Evaluation of Positions

PPC/NRU argue that in its FRN in this proceeding, BPA proposed several changes to the 1984 ASCM, 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 ASCM 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 ASCM. 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 argue that BPA's proposed changes to the 1984 ASCM 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 initially explained its rationales for its proposal in its original FRN. Since then, BPA has explained its position on the issues on numerous occasions through a number of workshops. In addition, any such claim is refuted by the administrative record, beginning with BPA's FRN and proceeding to the final comments BPA received on the proposed ASCM. Furthermore, when such a claim is made, a party should identify where the agency's proposed changes are allegedly unsupported. This allows the agency to review the record and its rationale and determine whether it has proposed a correct position. PPC/NRU do not specify any changes where justification is lacking. It is obviously difficult for an agency to respond to such sweeping, unspecific claims. BPA is unaware of any provision of the proposed ASCM that is contrary to the Northwest Power Act. Indeed, BPA believes the revised ASCM is consistent with the Act. Again, PPC/NRU have not identified any specific elements of the proposed ASCM 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.

PPC disagrees with BPA's conclusions regarding the justification of the proposed changes to the ASCM. (PPC, AS20003 at 13.) PPC claims the best example of BPA's flawed logic is the proposal to include ROE and Federal income taxes in ASC, despite the fact that ROE and Federal income taxes have been excluded from ASC for 24 years. (*Id.*) ROE and Federal income taxes have existed for the last 24 years, and yet only in 2008 has BPA proposed to increase ASC to include such amounts. (*Id.*) PPC claims this abrupt change of course is clearly driven by a judicial decision invalidating prior decisions of BPA, not by a reasoned approach to changed circumstances. (*Id.*) PPC's negative speculation and mischaracterization of the reasons for BPA's revision of the 1984 ASCM is inconsistent with the facts. When BPA's first ASCM was established in 1981, most provisions were established through negotiations and consensus. *See* Administrator's Record of Decision, Average System Cost Methodology, August 1981 at 2. In other words, all parties—preference customers, IOUs, DSIs, and BPA—agreed on the costs that were properly included in ASC under the Northwest Power Act and the structure of the Methodology. *Id*. No party, including BPA's preference customers, opposed the inclusion of IOUs' return on equity and income taxes in ASC. *Id*. Thus, all parties agreed that the IOUs' return on equity, income taxes, and transmission, among other costs, were properly included in ASC. BPA's 2008 ASCM therefore treats costs in a manner previously supported by BPA and its customers. If this is the result of "flawed logic," it is a logic that was shared by BPA with all of its customers, including preference customers.

Furthermore, BPA's development of the 2008 ASCM is not surprising in the context of the 2000 REP Settlement Agreements. As noted previously, in the development of those Agreements, BPA recognized that REP benefits could be significantly higher if BPA reviewed and adopted the IOUs' ASCM arguments regarding return on equity and income taxes. *See* Administrator' Record of Decision, Residential Exchange Program Settlement Agreements at 50. BPA recognized this was a serious possibility given that the Ninth Circuit did not sanction the permanent exclusion of return on equity and income taxes in ASC. *See PacifiCorp*, 795 F.2d at 823. The 2000 REP Settlement Agreements provided approximately $145 million in annual settlement benefits to the IOUs. BPA noted that if it revised the ASCM as advocated by the IOUs given the facts at that time, REP benefits would be approximately twice that amount. *Id*. BPA entered into the REP Settlement Agreements, in part, in order to manage its exposure to the IOUs' challenges to the 1984 ASCM. The IOUs' intent to challenge the 1984 ASCM when BPA developed new RPSAs for 2001 was stated in the IOUs' comments on the proposed 2001 RPSAs. *See* Administrator' Record of Decision, Residential Purchase and Sale Agreements at 11-24. Thus, once the 2000 REP Settlement Agreements were found unlawful and BPA reverted to implementing the REP, it is not surprising that the ASCM issues that had been dormant under the REP Settlement Agreements were addressed and resolved, with the result that BPA's ASCM includes return on equity and income taxes in ASC.

To provide some historical context to the development of BPA's 1984 ASCM, BPA's REP costs were increasing in 1984 as the REP ramped in from 50 percent of exchanging utilities' residential loads to 100 percent of such loads. 16 U.S.C. § 839e(c)(2). Under the Northwest Power Act's rate directives at that time, the majority of BPA's REP costs were paid through the rates charged to BPA's DSI customers. 16 U.S.C. § 839e(c)(1)(A). As the Ninth Circuit noted in *PacifiCorp v. FERC*, 795 F.2d 816, 823 (9th Cir. 1986), "the reduction in [Northwest Power] Act payments to the IOUs caused by the revised methodology is reflected in reduction in rates paid by the DSIs." The Court concisely summarized the facts leading to revision of the 1981 ASCM:

> . . . The second substantive change in ASCM, the disallowance of return on equity and the substitution for it of the embedded cost of long-term debt, is more troublesome. The exclusion of equity costs was a major departure from BPA's earlier practical judgment, in the exercise of the broad discretion that it interpreted the Act to provide, that such an action might unwisely encourage increase of long-term debt.
>
> Petitioners correctly observe that there is no logical congruence which would support making interest payments on debt a proxy for equity return. There is, as well, an inconsistency in first disallowing equity return and then further disallowing the taxes on such profits.
>
> BPA's justification for the change, however, is based not upon logic, but upon experience. BPA instituted this ratemaking proceeding only after the original methodology had been in effect for more than a year.
>
> By the time [BPA] completed its revised methodology, it had a considerable record of experience with the original methodology that reflected the dangers of improper manipulation of accounting classifications. Under certain "creative financing" devices, terminated plant costs (the costs of a Utility's investment in a power plant whose construction is terminated prior to its completion) could be reflected in higher equity return allowances, which are recognized by state regulatory agencies in setting rates. Under the initial methodology, the higher retail rates allowed a Utility to seek a higher subsidy from BPA, thereby indirectly reimbursing the Utility for its terminated plant costs. Yet such costs cannot lawfully be carried over into ASC rates because the Act expressly provides that plant termination costs must be excluded from calculation of average system costs. [Northwest Power] Act section 5(c)(7)(C), 16 U.S.C. § 839c(c)(7)(C), provides, "average system cost shall not include ... any costs of any generating facility which is terminated prior to initial commercial operation." Under the initial methodology, terminated plant costs could be improperly concealed in return on equity costs.
>
> The record shows at least one instance in which terminated plant costs were improperly included in return on equity costs. In 1983, BPA discovered that Portland General Electric Company (PGE) had violated the [Northwest Power] Act and Oregon law by concealing terminated plant costs in its ASC filing through a financing scheme

> approved by the Oregon Public Utility Commissioner. The Commissioner's retail rate determination had formed the basis of PGE's filing under the initial methodology. In *Coalition For Safe Power v. Oregon Public Utility Commission,* No. A 8210-06692 (Multnomah County Circuit Court, Apr. 19, 1985) (bench ruling of Circuit Court Judge Richard L. Unis), the court confirmed the existence of the financing scheme and found that it refunded terminated plant costs to shareholders in violation of Oregon law.
>
> BPA thus justifies its substitution of the cost of long term embedded debt for equity return as a way of "capping" BPA's subsidization of profits, in order to enforce the Act's exclusion of terminated plant costs from the ASC subsidy. We cannot hold that its action in this regard is irrational, as it is based upon a justifiable concern about abuse of the program. We therefore conclude that neither the change in ASC with respect to taxes nor the change with respect to equity violated the Act.

PacifiCorp, 795 F.2d at 823.

Most importantly for BPA's development of the 2008 ASCM, however, the Court recognized that although it approved the 1984 ASCM, it did not believe the exclusion of return on equity and income taxes should be permanent. 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 ASCM.

Id. (emphasis added).

Thus, contrary to PPC's claim, the fact that 24 years have passed since the establishment of the 1984 ASCM does not establish that return on equity and income taxes should be excluded from ASC. Just as BPA's experience under the 1981 ASCM identified a problem that had to be addressed, BPA's experience under the 1984 ASCM and changes in the state regulatory environment and regional energy industry have established that the reasons for excluding return on equity and income taxes from ASC no longer exist as they did in 1984.

PPC also argues that BPA's development of the 2008 ASCM is "clearly driven by a judicial decision invalidating prior decisions of BPA, not by a reasoned approach to changed circumstances." (PPC, AS20003 at 13.) PPC's negative characterization once again misses the mark. Although it is true that the Ninth Circuit found BPA's 2000 REP Settlement Agreements unlawful and this created the need to implement the REP in the absence of the settlements, BPA's development of the 2008 ASCM was triggered by the need to review a 24-year old Methodology before using it to implement the REP for the first time in 10 years in a new electric industry environment. This review was particularly appropriate given the Ninth Circuit's statement in *PacifiCorp* that it did not sanction permanent implementation of certain cost exclusions contained in the 1984 ASCM. *PacifiCorp,* 795 F.2d at 823. In addition, all of BPA's proposed revisions to the ASCM are supported by BPA's reasoned explanations of changed circumstances in this ROD.

Decision

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

4.10.12 Use of 2008 ASC Methodology for Determining FY 2002-2008 REP Benefits

Issue

Whether the 2008 ASCM should be used for determining REP benefits for the FY 2002-2008 period.

Parties' Positions

The IPUC supports the use of the proposed ASCM for WP-07 rate development and determining REP benefits for the WP-07 rate period. (IPUC, ASC0003 at 12.)

BPA's Position

In BPA's WP-07 Supplemental Proceeding, BPA is using the 1984 ASCM for purposes of calculating REP benefits for FY 2002-2008.

Evaluation of Positions

The IPUC supports the use of the results of the proposed ASCM in the WP07 Supplemental Proceeding. (IPUC, ASC0003 at 12.) The proposed changes to the ASC are appropriate, improve the accuracy of the ASC results, and are entirely consistent with and further promote the objectives of the Northwest Power Act. (*Id*.) The revised ASCM that results from this process is the methodology that should be used in determining the REP credits to be provided during the rate period covered by the WP-07 rate case. (*Id*.)

BPA understands the IPUC's argument, which the IPUC has also raised in BPA's WP-07 Supplemental Proceeding. This issue, however, will not be addressed in the instant consultation proceeding to revise the ASCM. The instant proceeding is to establish an ASCM to be used to implement the REP starting in FY 2009. The issue of whether BPA's 1984 ASCM or 2008 ASCM should be used for calculating REP benefits for purposes of the WP-07 Supplemental Proceeding is properly addressed and resolved in the WP-07 Supplemental Proceeding.

Decision

The ASCM will not decide in this consultation proceeding whether BPA should use the ASCM for calculating REP benefits in BPA's WP-07 Supplemental Proceeding.

4.10.13 Deemer Mechanism

Issue

Whether BPA should eliminate the "deemer" mechanism.

Parties' Positions

The IPUC suggests that BPA should revise the deemer mechanism such that no negative account balance is accumulated when a Utility's ASC falls below BPA's PF Exchange rate. (IPUC, ASC0003 at 10-11; IPUC, AS20005 at 2-4.) The IPC joins the comments submitted by the IPUC respecting treatment of deemer balances. (IPC, AS20010 at 1-2.)

BPA's Position

BPA is currently developing new Residential Purchase and Sale Agreements (RPSA) to implement the REP for FY 2009 and following. The deemer mechanism is established in the RPSA, not the ASCM.

Evaluation of Positions

In its Federal Register Notice for the proposed ASCM, BPA stated that a Utility's ASC is used to implement the REP pursuant to section 5(c) of the Northwest Power Act. 16 U.S.C. § 839c(c). BPA explained that when the 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.

73 Fed. Reg. at 7270, 7271 (Feb. 7, 2008). The Notice also states that "BPA has historically kept an account of such unpaid 'deemer' amounts, which must be paid before the Utility can receive positive REP benefits." *Id*. at n.4.

The IPUC notes that the existence of the deemer balances and the amount of such balances, if any, is a disputed issue in BPA's WP-07 Supplemental Proceeding. (IPUC, ASC0003 at 10-11; IPUC, ASC00__ at 2-4.) Unless the proposed ASCM addresses the deemer mechanism on a prospective basis, the legal and financial disputes that hang like a dark thundercloud over the REP in the past will continue to do so into the future. (*Id.*) Even taking into consideration the proposed changes to the ASCM, the possibility exists that one or more IOUs' ASCs will be lower than the PF Exchange rate in future years. (*Id.*) Moreover, there is no certainty that the current relationship between the IOUs' ASCs and BPA' s PF Exchange rate will remain the same over time. (*Id.*) In 2008, the electric Utility industry still faces a great deal of uncertainty regarding resources, for example: carbon-based emissions, the integration of renewable resources, the construction of major transmission lines, new technologies for generation and customer resources, and environmental mitigation. (*Id.*) How the resolution of these uncertainties will affect the IOUs' costs/ASCs, BPA's PF Exchange rate, and the relationship between the two is unknown at this time. (*Id.*)

To provide fairness and clarity to the REP on a going forward basis, the IPUC believes BPA should change the deemer mechanism in the following manner: when an IOU's ASC is lower than the BPA PF Exchange rate, nothing should occur beyond the fact that the IOU will not be eligible for current REP benefits and no payment flows from the Utility to BPA. (*Id.*) Requiring an IOU to pay the difference (*i.e.*, when the Utility's ASC is lower than the PF Exchange rate) before receiving future REP benefits goes beyond the concept of "wholesale rate parity" between preference customers and IOU customers embodied in the Northwest Power Act. (*Id.*) In fact, this payment by an IOU may constitute a subsidy of either the other IOUs' REP benefits or the public utilities' rates or both. (*Id.*)

The IPUC argues it is disingenuous to state that the reduction of future REP benefits through the deemer mechanism is not the same as a "cash obligation." (*Id.*) If left unchecked, the alleged growth in the deemer balances by the accumulation of applied interest alone, the inability of the parties to resolve the deemer disputes, and BPA' s position that the deemers must be paid before utilities can receive positive REP payments, will result in hundreds of thousands of Idaho residential and small farm customers being denied any REP benefits for the next 20 years. (*Id.*) Adopting a policy suspending an IOU's participation in the REP (without accruing interest) when its ASC is lower than the PF Exchange rate, but to resume receiving REP benefits when its ASC is higher than the PF Exchange rate, is a solution that is easy to understand and implement, harms no other party, and is consistent with the Northwest Power Act. (*Id.*)

BPA notes that the deemer mechanism is not established in the ASCM, but instead is established in the RPSAs. BPA currently is requesting comments from interested parties on the prototype RPSAs recently published by BPA, including the deemer provision. BPA respects the comments of the IPUC on this issue and encourages the Commission to submit its comments on the deemer mechanism in the RPSA forum.

<u>Decision</u>

The ASCM will not decide issues regarding the deemer mechanism in this ASCM proceeding, but will address such issues in the concurrent proceeding to develop RPSAs for exchanging utilities.

5. NATIONAL ENVIRONMENTAL POLICY ACT ANALYSIS

BPA evaluated the proposed changes to the average system cost methodology under the National Environmental Policy Act (NEPA) 42 U.S.C. § 4321 et seq. The changes include: 1) redefining the types of capital and expense items includable in ASC; 2) establishing new data sources from which ASCs are to be derived; and 3) changing the nature and timing of BPA's procedures for review of ASC filings by utilities participating in the REP. These actions are primarily administrative in nature and accordingly would not be expected to result in environmental effects. In addition, it is expected that there would be no substantial change in consumer or utility behavior because there would be no resource or transmission development that would result from implementation of the methodology. Further, these types of business activities are the type anticipated in BPA's Business Plan Environmental Impact Statement (DOE/EIS-0183, June 1995), and are consistent with BPA's Market-Driven approach adopted in its Business Plan ROD (August 15, 1995). (See Business Plan EIS, Table 2.4.1, on *Determination of Firm Loads* and the Market-Driven Alternative, page 2-36; see also *Delivery of Power Under Residential Exchange Agreements*, Business Plan EIS, page 4-10.)

6. FINDINGS AND CONCLUSION

Following the consultation proceeding required by section 5(c)(7) of the Northwest Power Act, 16 U.S.C. § 839c(c)(7), and in consideration of the foregoing discussion, the Administrator adopts the Methodology set forth in this Record of Decision as the new administrative rule governing the calculation of the average system cost of resources for utilities participating in the Residential Exchange Program. 16 U.S.C. § 839c(c). The Methodology will now be submitted to the Federal Energy Regulatory Commission for review and approval in accordance with section 5(c)(7) of the Northwest Power Act. 16 U.S.C. § 839c(c)(7).

Issued in Portland, Oregon

DATED this 30th of June, 2008

*/s/ Stephen J. Wright*_______________
Stephen J. Wright
Administrator

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DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION

ATTACHMENT A TO THE FINAL RECORD OF DECISION OF THE 2008 AVERAGE SYSTEM COST METHODOLOGY

2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act

June 2008

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ATTACHMENT A
ASC METHODOLOGY

TABLE OF CONTENTS

Page

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AVERAGE SYSTEM COST METHODOLOGY
BONNEVILLE POWER ADMINISTRATION

The following rules set forth the procedures by which regional utilities will submit Average System Cost (ASC) filings to the Bonneville Power Administration (BPA) and by which BPA will review such filings. BPA's review shall determine a Utility's ASC for the purpose of participating in the Residential Exchange Program (REP) pursuant to section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). 16 U.S.C. § 839c(c).

I. DEFINITIONS

A. **Appendix 1:** Appendix 1 is the electronic form on which a Utility reports its Contract System Costs and other necessary data to BPA for the calculation of the Utility's Base Period ASC.

B. **Average System Cost:** The rate charged by a Utility to BPA for the agency's purchase of power from the Utility under section 5(c) of the Northwest Power Act for each Exchange Period and is the quotient obtained by dividing Contract System Costs by Contract System Load.

C. **Base Period:** The calendar year of the most recent FERC Form 1 data.

D. **Base Period ASC:** The ASC determined in the Review Period using the Utility's Base Period data.

E**. Contract High Water Mark (CHWM):** The aMW amount used to define access to Tier 1-priced power. CHWM is equal to the adjusted historical load for each customer proportionately scaled to Tier 1 System Resources and adjusted for conservation achieved. The CHWM is specified in each eligible customer's Contract High Water Mark Contract.

F. **Commission:** The Federal Energy Regulatory Commission.

G. **Contract System Costs:** The Utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. Under no circumstances shall Contract System Costs include costs excluded from ASC by section 5(c)(7) of the Northwest Power Act.

H. **Contract System Load:** The total regional retail load included in the Form 1, or for a consumer-owned utility (preference customers) the total retail load from the most recent annual audited financial statement as adjusted pursuant to this Average System Cost Methodology.

I. **Exchange Period:** The period during which a Utility's BPA-approved ASC is effective for the calculation of the Utility's REP benefits. The initial Exchange Period under this ASC Methodology is from October 1, 2008, through September 30, 2009. Subsequent Exchange

Periods shall be the period of time concurrent with the BPA rate period beginning October 1, or the effective date of BPA's rate period.

J. **Exchange Period ASC:** The Base Period ASC escalated to a year(s) consistent with the Exchange Period.

K. **Form 1:** The annual filing submitted to the Federal Energy Regulatory Commission required by 18 CFR §141.1.

L. **Jurisdiction:** The service territory of the Utility within which a particular Regulatory Body has authority to approve a Utility's retail rates. Jurisdictions must be within the Pacific Northwest region as defined in the Northwest Power Act.

M. **Labor Ratios:** The ratios which assign costs on a pro rata basis using salary and wage data for production, transmission, and distribution/other functions included in the Utility's most recently filed Form 1. For consumer-owned utilities, comparable data shall be used based on the cost of service study used as the basis for retail rates at the time of review.

N. **New Large Single Load:** That load defined in section 3(13) of the Northwest Power Act and determined by BPA as specified in power sales contracts and Residential Sale and Purchase Agreements (RPSA) with its Regional Power Sales Customers.

O. **Public Purpose Charge:** Any charge based on a Utility's total retail sales in a Jurisdiction that is given to independent non-profit entities or agencies of state and local governments for the purpose of funding within the Utility's service territory: (i) conservation programs in lieu of utility conservation programs; and (ii) acquisition of renewable resources.

P**. Rate Period High Water Mark (RHWM).** The amount used to define each customer's eligibility to purchase power at a Tier 1 price for the relevant Rate Period, subject to the customer's Net Requirement, expressed in average megawatts (aMW). RHWM is equal to the customer's CHWM as adjusted for changes in Tier 1 System Resources. The RHWM is determined for each eligible customer in the RHWM Process preceding each rate case.

Q. **Regional Power Sales Customer:** Any entity that can contract directly with BPA for the purchase of power under sections 5(b), 5(c), or 5(d) of the Northwest Power Act for delivery in the region as defined by section 3(14) of the Northwest Power Act.

R. **Residential Purchase and Sale Agreement (RPSA):** The power sales contract pursuant to section 5(c) of the Northwest Power Act between BPA and the Utility that defines and implements the power purchase and sale.

S. **Review Period:** The period of time during which a Utility's Appendix 1 is under review by BPA. The Review Period begins on June 1 and ends on or about November 15 of the fiscal year prior to the fiscal year BPA implements a change in wholesale power rates.

T. **Regulatory Body:** A state commission or consumer-owned utility governing body, or other entity authorized to establish retail electric rates in a Jurisdiction.

U. **Utility:** An investor-owned or consumer-owned (preference) Regional Power Sales Customer that has executed a Residential Purchase and Sale Agreement.

II. FILING PROCEDURES

The following procedures state the filing requirements for all Utilities that file an Appendix 1 to participate in the REP. Utilities must file an Appendix 1 with BPA to permit the calculation of each Utility's ASC.

A. <u>Initial Exchange Period (FY 2009) and Second Exchange Period (FY 2010-2011).</u>

1. A Utility's ASC for fiscal year FY 2009 shall be determined by BPA in accordance with this ASC Methodology and shall constitute the effective ASC for the REP effective October 1, 2008, unless (1) the Commission fails to approve this Methodology; (2) the Commission amends the Methodology in a manner that changes the Utility's ASC established by BPA; or (3) the Methodology is legally challenged and not affirmed on appeal by the United States Court of Appeals for the Ninth Circuit. The Base Period Appendix 1 filing will be from CY 2006.

2. The initial Exchange Period under this Methodology shall commence October 1, 2008, provided that the Commission has granted the Methodology interim or final approval by that date. The initial Exchange Period shall end on September 30, 2009.

3. Since the initial Exchange Period under this Methodology commences on October 1, 2008 and the Utility filings for FY2009 are also due that same day, BPA will pay the exchanging Utilities based on their October 1, 2008 filed ASC and then calculate a true-up to the final ASC after the BPA Review Period is concluded and BPA has issued the final ASC reports. If a Utility has failed to file an Appendix 1 by October 1, 2008, BPA will follow the procedures outlined in section *C. Failure to File an Appendix 1 and Patently Deficient Appendix 1*. Prior to the commencement of the BPA Review Process in this Methodology, BPA will publish a schedule for the review of the filings. BPA may issue a schedule different from the prescribed schedule in order to ensure that ASCs are established in time to be trued-up during FY 2009.

4. For the Second Exchange Period, Utilities are required to submit their ASC filings by October 1, 2008 for FY 2010-2011. If a Utility has failed to file an Appendix 1 by October 1, 2008, BPA will follow the procedures outlined in section C. *Failure to File an Appendix 1 and Patently Deficient Appendix 1*. Prior to the commencement of the BPA Review Period in this Methodology, BPA will publish a schedule for the review of the filings. BPA may issue a schedule different from the prescribed schedule in order to ensure that ASCs are established in time to be incorporated in BPA's FY 2010-2011 wholesale power rate case.

After BPA's Review Process is concluded, BPA will issue Utility ASC Reports to reflect the final Utility ASCs for the FY2010-2011 rate period.

B. Subsequent Exchange Period Filing Requirements

1. Subsequent Exchange Periods shall be equal to the term of subsequent BPA wholesale power rate periods. ASCs shall change during such Exchange Periods only for the reasons provided in this Methodology.

2. Except as provided for the initial and second Exchange Periods under this Methodology, Utilities shall electronically file at least one Appendix 1 with BPA by June 1 of each year. In years when BPA is not conducting a review process, these filings shall be for informational purposes only and shall not change a Utility's ASC. The Appendix 1 shall be accompanied by supporting documentation, studies and analysis used to prepare the Appendix 1. For investor-owned utilities, the Appendix 1 shall be based on the Utility's most recently filed Form 1 and limited information from prior FERC Form 1 filings as required. For consumer-owned utilities, the Appendix 1 shall be based on the Utility's most recent audited financial information and shall be accompanied by a cost of service analysis (COSA). Each Appendix 1 shall contain an attestation signed by a senior officer of the Utility stating that the filing has been compiled in accordance with the Commission's Uniform System of Accounts, this ASC Methodology, and Generally Accepted Accounting Principles and is consistent with applicable orders and policies of the Utility's Regulatory Body. See Appendix 2.

C. Failure to File an Appendix 1 and Patently Deficient Appendix 1

1. Failure to File an Appendix 1. If a Utility fails to timely file an Appendix 1 and refuses to cure the problem within the *Period to Cure* provided in step 3 below, 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 the 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.

2. Filing a Patently Deficient Appendix 1. If a Utility files its initial Appendix 1 and it is patently deficient as determined by BPA and the period to cure, as outlined in paragraph 3 below, has expired, 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 filing a patently deficient ASC filing will also allow BPA the 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.

3. Period to Cure. If a Utility fails to timely file an Appendix 1, 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) calendar 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 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 filing a patently deficient ASC filing 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.

D. Failure to File an Appendix 1 because of a New Residential Purchase and Sale Agreement

1. *New Residential Purchase and Sale Agreement.* After the initial and second Exchange Periods, if a Utility fails to file its Appendix 1 by June 1 because it executed a Residential Purchase and Sale Agreement after the commencement of a Review Period or during the subsequent Exchange Period, then BPA may set the Utility's ASC equal to the PF Exchange rate until the end of the Exchange Period.

E. Notice of Filing of Appendix 1

1. After a Utility files electronically an Appendix 1, BPA shall post the filings and non-confidential documentation on BPA's electronic website. Access to such information shall be subject to any confidentiality rules or requirements established by BPA.

2. BPA shall advise parties of the right to file a petition to intervene in BPA's ASC review process.

III. BPA REVIEW PROCESS

During a Review Period, the following procedures apply. These procedures shall not apply to informational ASC filings made outside of a Review Period.

A. BPA may petition to 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 intervene in a retail rate review proceeding of a filing Utility when such intervention is for purposes of obtaining any information regarding costs or facts relevant to the determination of a Utility's ASC (after having made a good faith effort to intervene in such retail rate proceeding and having timely complied with applicable procedures to intervene in such retail rate proceeding), BPA may set that Utility's ASC equal to the PF Exchange Rate for the following Exchange Period. Exchanging Utilities must provide BPA and Regional Power Sales Customers with at least 60 days notice of their intent to change their retail rates.

B. Each Appendix 1 shall be reviewed by BPA or its designee and subject to a public process to determine whether the Contract System Costs are consistent with Generally Accepted Accounting Principles for electric utilities, whether Contract System Costs contain only allowed costs, and whether the revised Appendix 1 complies with the requirements of this Methodology, including applicable definitions and requirements incorporated from the Commission's Uniform System of Accounts. In addition, each Appendix 1 shall be reviewed by BPA or its designee to determine whether the Contract System Load used by the Utility is an appropriate load for purposes of the Utility's ASC computation.

C. In calculating ASCs, BPA will make an independent determination of (1) the appropriateness of the inclusion of costs; (2) the reasonableness of the costs included in Contract System Costs; and (3) the appropriateness of Contract System Loads. BPA shall not be obligated to pay an ASC different than the ASC based on Contract System Costs and Contract System Load as determined by BPA; provided that if a final order of the Commission or a reviewing court rejects BPA's ASC determination, then the ASC payable by BPA shall be the ASC as revised by BPA on remand.

D. The Appendix 1 filing shall be subject to review as follows:

The BPA review process (not including the initial and second Exchange Periods) commences on June 1 (Day 1) of the Review Period (or such other date as may be established by BPA). BPA will review all Utilities' ASCs concurrently in a public process.

Note: The dates identified below and those listed on the Sample Timeline on pages 13-14 herein are generic and intended to illustrate a timeline that is representative of the ASC review process. Unless specified, the days listed represent calendar days. Each spring prior to the Review Period, BPA will post on its ASCM website (http://www.bpa.gov/corporate/finance/ascm/) or its successor, a detailed schedule, accommodating the applicable holidays and weekends, that shall be the official schedule for that Review Period.

1. Day 1: Utility filings due to BPA.

2. Day 3: BPA posts the Utility filings to its electronic website. Access to such information shall be subject to any confidentiality rules or requirements established by BPA.

3. Day 7: Deadline to file Utility specific petitions to intervene with BPA for the Review Process. 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. Other interested parties also may submit a petition to intervene and BPA shall grant party status at BPA's discretion. Petitions to intervene must state with particularity the petitioner's interest in the ASC review proceeding. Petitions to intervene must be filed for each respective BPA review proceeding in order for a party to comment on such individual proceedings. The filing Utility is automatically a party to its own ASC review proceeding. BPA will grant or deny petitions to intervene within seven days after the deadline for filing such petitions.

4. Day 10: BPA grants or denies petitions to intervene

5. Day 11-66: Parties allowed to submit Data Requests. BPA and parties shall electronically file data requests to the Utility and BPA. BPA will make data requests available to all parties. Each Utility shall respond to requests for information relevant to the Utility's Appendix 1 filing, provided that the furnishing of proprietary or confidential information to any party may be made

contingent on the granting of proper safeguards to prevent unauthorized use or disclosure. The responses should be sent to the requestor and BPA.

For each data request, the responding Utility has 7 days to provide the requested data or object. If a Utility files an objection to a data request, the party submitting the data request has 4 days to respond to the objection. After the response to the objection is received or the 4 days to respond has elapsed, BPA then has 7 days to issue a ruling as to whether the Utility's objection will be sustained or overruled. If the objection is overruled, the Utility must provide the data requested within 7 days after the ruling. If a Utility does not provide requested data, BPA may, in its discretion, remove from Contract System Costs all costs associated with the data not provided.

6. Day TBD: BPA will commence workshops on all Appendix 1 filings based on the specific schedules. Utilities filing Appendix 1s shall have staff or agents available for questioning by BPA and other parties to the proceeding. The primary purpose of the first workshop is to clarify data, work papers, supporting documentation and assumptions used to prepare the Appendix 1.

7. Day 88: By this day, BPA and parties may electronically file with BPA an issues list identifying contested elements of a Utility's ASC filing and the basis for the party's issues. BPA will make the issues lists available to all parties.

8. Day 102: By this day, each filing Utility will electronically file a response to issues lists. BPA and other parties also may file comments in response to issue lists.

9. Day 108: By this day, a workshop will be held to discuss and resolve issues raised by parties through their issues lists.

10. Day 111: Requests for oral argument before the Administrator or his/her designee must be submitted in writing to BPA by this day. Such requests shall contain a statement setting forth reasons why the party believes oral argument is necessary.

11. Day 114: BPA, at its discretion, may grant or deny any request for oral argument by this day.

12. Day 123: In the event a request for oral argument is granted, the requesting party shall present its argument first. Responding parties shall present their arguments thereafter. The Administrator or his/her designee, at his discretion, may provide an opportunity for the requesting party to reply. Oral argument shall be presented no later than this day.

13. Day 141: By this day, BPA will publish for comment and electronically serve Draft Utility ASC Reports on all parties. The Reports will contain analyses and decisions on all contested issues raised in the ASC review process.

14. Day 154: By this day, the Utility and parties may file comments on the Draft Utility ASC Reports.

15. Day 167: The BPA Administrator will issue Final Utility ASC Reports.

16. If BPA has not issued the Final Utility ASC Reports by the end of the Review Period, the ASC filed by the Utility shall be the Exchange Period ASC until the date BPA issues the Final Utility ASC Reports. The final ASCs determined by BPA shall then be the Exchange Period ASCs, effective back to the beginning of the Exchange period and until the end of the Exchange Period.

IV. RULES FOR DETERMINING EXCHANGE PERIOD AVERAGE SYSTEM COST

A. Escalation to Exchange Period

1. BPA will escalate BPA approved 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.

2. For purposes of the escalation referenced in paragraph 1 above, 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. The following list of acronyms defines Global Insight's escalation codes, with exception of the natural gas escalator which is provided by BPA.

A&G	Administrative and General
CACNT	Customer Account
CD	Construction, Distribution Plant
CONSTANT	Constant
CSALES	Customer Sales
CSERV	Customer Service
COAL	Coal
DMN	Distribution Maintenance
DOPS	Distribution Operations
HMN	Hydro Maintenance
HOPS	Hydro Operations
INF	Inflation
NATGAS	Natural Gas
NFUEL	Nuclear Fuel
NMN	Nuclear Maintenance
NOPS	Nuclear Operations
OMN	Other Production Maintenance
OOPS	Other Production Operations
SMN	Steam Maintenance
SOPS	Steam Operations
TMN	Transmission Maintenance

TOPS	Transmission Operations
WAGES	Wages

Table 1 in section VIII shows the escalators to be used for each line item included in the Appendix 1.

3. If any of the escalators specified in the ASCM are no longer available, BPA will designate a replacement source of escalators that, as near as possible, replicates the results produced by the prior escalator and, if such a replacement source is not available, the replacement escalator will be the forecast of the GDP Price Deflator.

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

B. Treatment of Sales for Resale and Power Purchases

1. 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.

2. 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 as the starting values. A Utility will then be allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue to be included in the Rate Period ASC.

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

a. The Utility's 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 (Base Period and prior two years).

b. The mid-point between the Utility's average short term purchased power price and short term sales for resale price will be calculated for each of the years in 1.

c. The percentage spread around the Utility's mid-point between the average short term purchase power price and short term sales for resale price will be calculated for each of the years in 1.

d. A weighted average spread for the Utility's most recent three years of actual data (Base Period and prior two years) will then be calculated. The following weighting scale will be used:

    i. 3 times Base Period spread

ii. 2 times (Base Period year minus 1) spread
iii. 1 times (Base Period year minus 2) spread

e. The Base Period mid-point price calculated in 2 will be escalated at the same rate as BPA's market price forecast.

f. The weighted average spread calculated in 4 will then be applied to the forecasted mid-point calculated in 5 to determine the purchased power and sales for resale price, to value purchased power expenses and sales for resale revenue to be included in Rate Period ASCs.

g. This same method will be used to calculate the market price forecast for short-term purchased power expense and sales for resale revenues for use in the load growth not met by new resource additions.

C. Major Resource Additions and Materiality Thresholds

During the Exchange Period, BPA will allow changes to a Utility's ASC to account for major new purchase power contracts or major new resource additions that come on-line and are used to meet the Utility's retail load. These changes, however, have to meet a materiality threshold in order for BPA to allow an ASC to change. These ASCs will be determined by BPA during the Review Period. The changes to the ASC will become effective when the resource begins commercial operation or power is received under the purchase power contract. Such criteria will also apply to resources that are sold, transferred or retired.

BPA will use the following method to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold. These additions will include new production resource investments, new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments.

1. BPA will apply a materiality threshold of a 2.5 percent change in a Utility's Base Period ASC for determining when a change in ASC will be allowed for resource additions or reductions. BPA will allow a Utility to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more. This treatment allows an exchanging Utility to include resources required under state renewable resource mandates while lessening the administrative cost and burden of verifying the resource cost estimates during the ASC Review Period.

2. At the time the Utility submits its Appendix 1 filing, the exchanging Utility will provide its forecast of major new 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.

3. BPA will calculate new transmission wheeling revenues associated with new transmission investment by the following formula:

$$NTWR = WR_{(\text{before additions})} * [(NTP_{(\text{before additions})} + NTA) / NTP_{(\text{before additions})}]$$

Where:

- NTWR = New transmission wheeling revenues
- $WR_{(\text{before additions})}$ = wheeling revenues (before additions)
- $NTP_{(\text{before additions})}$ = (Net Transmission Plant (before additions)
- NTA = new transmission additions

4. The forecast of the major new resource costs to be included in the Utility's Exchange Period ASC will be reviewed and determined during the Review Period.

5. All major new resources included in an ASC calculation prior to the start of the Exchange Period will be projected forward to the mid-point of the Exchange Period.

6. For each major new 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.

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

8. Steps 1 through 7 above will also be used in a similar manner for resources that are sold, transferred or retired.

9. BPA will 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.

10. 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. BPA will provide parties with an opportunity to comment on the rules prior to their implementation in the 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 IV.E. of this Methodology. 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.

D. Forecasted Contract System and Exchange Load

All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss study as described in endnote e/, with their Appendix 1 filing. The load forecast for Contract System Load and Exchange Load will start with the Base Period and extend through 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load will be provided on a monthly basis for the Exchange Period.

E. Load Growth Not Met by New Resource Additions

All forecast load growth not met by new resource additions will be met by purchased power at the forecasted Utility-specific short-term purchased power price.

1. The Utility's forecast load growth will be met with market purchases priced at the Utility's forecast short-term purchased power price unless the Utility has forecasted major resource additions.

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

3. In the event that the power provided by a new resource exceeds the Utility's forecast load growth, the excess will be sold as surplus power into the market and priced at the Utility's forecast sales for resale price as determined by BPA in section IV.B.

F. Changes to Service Territory

In the event a Utility forecasts that it will acquire a new service territory or lose a portion of its service territory, and the resulting change in ASC falls within the 2.5% or greater materiality threshold, the Utility will submit two ASC filings:

1. A Base Period ASC that does not reflect the acquisition or loss of service territory, and

2. A second filing that incorporates:

a. The forecast of the increase or reduction in Contract System Load associated with the acquisition or reduction in service territory.

b. The forecast of the increase or reduction in Contract System Costs associated with the acquisition or relinquishment of the service territory.

c. In addition to including the forecast of capital and operating cost increases or reductions associated with the change in service territory, the Utility must also forecast 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 actual change to the Utility's service territory could differ from the forecast date used to determine the ASC during the Review Period, BPA will not adjust the Utility's ASC until the change in service territory takes place.

G. <u>ASC Determination for COUs that elect to execute Regional Dialogue HWM Contracts</u>

BPA will utilize the following approach:

1. Use the RHWM System Load as determined in the Tiered Rates Methodology (TRM) process.

2. Determine the RHWM 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 resources in excess of the resource amounts used to calculate its CHWM.

4. Calculate the Utility's Total Unadjusted Contract System Cost (CSC) as described in the ASCM

5. Calculate a load growth credit {(Current System Load minus RHWM system Load) * Unit costs from 3 above}.

6. Total Exchangeable Contract System Cost = Total Unadjusted CSC minus load growth revenue credit (from 5 above).

7. HWM Average System Cost = Total Exchangeable Contract System Cost / RHWM System Load.

H. <u>Timely filing of Appendix 1</u>

Utilities must file ASC information by June 1 each year, as required in section II, for BPA's review and determination of a Base Period ASC. Utilities will file multiple, contingent, Base Period ASC filings to reflect changes to service territories as required in section F above.

V. CHANGE IN AVERAGE SYSTEM COST METHODOLOGY

The Administrator, at his or her discretion, or upon written request from three-quarters of the Utilities that are parties to contracts authorized by section 5(c) of the Northwest Power Act, or from three-quarters of BPA's preference customers, or from three-quarters of BPA's direct-service industrial customers may initiate a consultation process as provided in section 5(c) of the Northwest Power Act. After completion of this process, the Administrator may file a new ASC Methodology with the Commission. However, the Administrator shall not initiate any consultation process until one year of experience has been gained under the then-existing ASC Methodology, *viz;* one year after the then-existing Methodology has been adopted by BPA and approved by the Commission through interim or final approval, whichever occurs first.

The Administrator may, from time to time, issue interpretations of the ASC Methodology. The Administrator also may modify the functionalization code of any Account to comply with the limitations identified in section 5(c)(7)(A)-(C) of the Northwest Power Act or to conform to the Federal Energy Regulatory Commission's revisions to the Uniform System of Accounts.

VI. SAMPLE TIMELINE REVIEW PROCEDURES

Note: BPA's ASC review process of Utilities' Appendix 1s occurs only in the year before BPA establishes new Wholesale Power Rate Schedules. However, Utilities are required to file an Appendix 1 by June 1 of each year in order that BPA can maintain current data.

The schedule below is a generic schedule that is representative of the timeline for the ASC review process. Each spring in the year prior to BPA implementing new Wholesale Power Rates, BPA will post a detailed schedule incorporating the applicable holidays and weekends.

DAY[1]	**EVENT**
June1	Utilities file electronic Appendix 1s with BPA.
June 7	Deadline to file petitions to intervene with BPA.
June 10	BPA grants or denies petitions to intervene.
June 11	Begin Data Request period.
TBD	Workshop(s) on Utilities' Appendix 1 filings.
Aug 22	End Data Response period.
Aug 27	Deadline for BPA and parties' issue lists on Utilities' filings.
Sept 10	Deadline for reply issue lists from all parties on Utilities' filings.
Sept 16	Workshop to discuss issue lists on Utilities' filings.
Sept 19	Deadline to request oral argument.
Sept 22	BPA grants or denies requests for oral argument.
Oct 1	Oral argument (if granted).
Oct 19	BPA publishes Draft ASC Report.
Nov 1	Deadline for Utilities' and parties' comments on Draft ASC Report.
Nov 14	BPA Administrator issues Final ASC Report.

[1] Deadlines end at 5 p.m., Pacific Prevailing Time, of the due date.

VII. APPENDIX 1 INSTRUCTIONS

Appendix 1 is the form on which a Utility reports its Contract System Costs, Contract System Loads, and other necessary data for the calculation of ASC. Appendix 1 is an electronic template consisting of seven schedules and several supporting files that must be completed by the Utility in accordance with these instructions and the provisions of the Endnotes following the schedules.

Appendix 1 filings must be accompanied by an Attestation Statement of the Chief Financial Officer of the Utility or other responsible official who possesses the financial and accounting knowledge necessary to complete the Attestation Statement. The ASC Filing Attestation Statement is presented at Appendix 2. The primary source of data for the investor-owned utilities' Appendix 1 filings is the Utility's prior year FERC Form No. 1 (Form 1) filing. Any items not applicable to the Utility shall be so identified. For consumer-owned utilities that do not follow the Commission Accounts, filings must include reconciliation between Utility Accounts and the items allowed as Contract System Costs. In addition, the COSA must be reviewed by an independent accounting or consulting firm. The COSA report must be accompanied by a report from an independent accounting firm or a consulting firm that outlines the review work that was performed in preparing the COSA report along with an assurance statement that the information contained in the COSA report is presented fairly in all material respects. The COSA report statement is presented in Appendix 2, Exhibit A, Statement of Review and Compilation of Work Performed. An outline of the financial documents that accompany an ASC filing for both investor-owned utilities and consumer-owned utilities is presented in Appendix 2, Exhibit B.

The primary schedules are as follows. The ASC Appendix 1 template is available electronically at http://www.bpa.gov/corporate/finance/ascm/, or its successor site.

Schedule 1: Plant Investment/Rate Base
Schedule 1A: Cash Working Capital
Schedule 2: Capital Structure and Rate of Return
Schedule 3: Expenses
Schedule 3A: Taxes
Schedule 3B: Other Included Items
Schedule 4: Average System Cost

The filing Utility shall reference and attach work papers, documentation and other required information that supports costs and loads, including details of allocation and functionalization. All references to the Commission Accounts are to the Commission's Uniform System of Accounts as of July 1, 2006 or as amended by subsequent Commission actions. The costs includable in the attached schedules are those includable by reason of the definitions in the Commission Accounts. If 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.

BPA may require a Utility to account for all transactions with affiliated entities as though the affiliated entities were owned in whole or in part by the Utility, if necessary, to properly determine and/or functionalize the Utility's costs.

A Utility operating in more than one Pacific Northwest Jurisdiction shall file one Appendix 1.

A Utility operating in Jurisdictions outside the Pacific Northwest shall allocate its total system costs among its Jurisdictions within the Pacific Northwest and outside the Pacific Northwest in accord with the same allocation methods and procedures used by the Regulatory Body(ies) to establish Jurisdictional costs and resulting revenue requirements. Such Utility's Appendix 1 filing shall include details of the allocation.

This allocation shall exclude all costs of additional resources used to meet loads outside the region, as required by section 5(c)(7) of the Northwest Power Act. All schedule entries and supporting data shall be in accord with Generally Accepted Accounting Principles and practices as these principles and practices apply to the electric utility industry.

A Utility shall file an Attestation Statement with each Appendix 1 filing and supporting documentation for each Review Period. See Appendix 2.

VIII. AVERAGE SYSTEM COST METHODOLOGY FUNCTIONALIZATION

Functionalization of each Account included in a Utility's Average System Cost (ASC) shall be according to the functionalization prescribed in Table 1, *Functionalization and Escalation Codes*, beginning on page 18. Direct Analysis on an Account may be performed only if Table 1 states specifically that a Utility may perform a Direct Analysis on the Account with the exception of conservation costs. Utilities will be able to functionalize all conservation-related costs to Production, regardless of the Account in which they are recorded. The Direct Analysis must be consistent with the directions provided below.

The following chart identifies the functionalization codes:

DIRECT	Direct Analysis
PROD	Production
TRANS	Transmission
DIST	Distribution/Other
PTD	Production, Transmission, Distribution/Other Ratio
TD	Transmission, Distribution/Other Ratio
GP	General Plant Ratio
GPM	General Plant Maintenance Ratio
PTDG	Production, Transmission, Distribution/Other, General Plant Ratio
LABOR	Labor Ratio

A. Functionalization Rules:

1. 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.

2. The Utility must submit with its Appendix 1 any and all work papers, documents, or other materials that demonstrate that the functionalization under its Direct Analysis assigns costs based upon the actual and/or intended functional use of those items. Failure to submit such documentation could result in the entire Account being functionalized to Distribution/Other, or Production, or Transmission, as appropriate.

B. Functionalization Methods:

1. Direct Analysis, if allowed or required by Table 1, assigns costs to the production, transmission, and/or distribution function of the Utility. The only exception to this requirement is for conservation-related costs. Utilities will be able to identify and functionalize to Production any conservation-related costs, irrespective of the Account in which they are recorded. Such analysis is subject to BPA review and approval. 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.

2. BPA will not allow Utilities to use a combination of Direct Analysis and a prescribed functionalization method for the same Account. The Utilities can develop and use a functionalization ratio or use a prescribed functionalization method if the Utility through Direct Analysis can justify how the ratio adequately reflects the functional nature of the costs included in any Account or cost item being functionalized by the ratio.

3. Utilities that wish to include advertising and promotion costs related to conservation will do so with a Direct Analysis. If a Utility records conservation costs in an Account that is normally functionalized to Distribution/Other, the Utility will identify and document the conservation-related costs included in the Account, and the balance of the costs will be functionalized to Distribution/Other. The presence of conservation-related costs in an Account does not give the Utility permission to perform a Direct Analysis on the entire 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 that demonstrate such cost assignment is appropriate. The Utility must submit with its ASC filing any and all work papers, documents, and other materials that demonstrate 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 the exception of items included in Schedule 3B, *Other Included Items*, where certain Accounts shall be functionalized to Production as appropriate.

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2008 Average System Cost Methodology Functionalization and Escalation Codes				
Account Description	**Acct No.**	**Functionalization Codes**		**Escalation Codes**
		Method	**Default**	
Schedule 1: Plant Investment/Rate Base				
Intangible Plant:				
Intangible Plant - Organization	301	DIST		CONSTANT
Intangible Plant - Franchises and Consents	302	DIRECT	PTD	CONSTANT
Intangible Plant - Miscellaneous	303	DIRECT	DIST	CONSTANT
Production Plant:				
Steam Production	310-317	PROD		CONSTANT
Nuclear Production	320-326	PROD		CONSTANT
Hydraulic Production	330-337	PROD		CONSTANT
Other Production	340-347	PROD		CONSTANT
Transmission Plant:				
Transmission Plant	350-359.1	TRANS		CONSTANT
Distribution Plant:				
Distribution Plant	360-374	DIST		CD
General Plant:				
Land and Land Rights	389	PTD		CONSTANT
Structures and Improvements	390	PTD		CONSTANT
Furniture and Equipment	391	LABOR		CONSTANT
Transportation Equipment	392	TD		CONSTANT
Stores Equipment	393	PTD		CONSTANT
Tools, Shop and Garage Equipment	394	PTD		CONSTANT
Laboratory Equipment	395	PTD		CONSTANT
Power Operated Equipment	396	TD		CONSTANT
Communication Equipment	397	PTD		CONSTANT
Miscellaneous Equipment	398	PTD		CONSTANT
Other Tangible Property	399	DIRECT	PTD	CONSTANT
Asset Retirement Costs for General Plant	399.1	PTD		CONSTANT
Depreciation Reserve:				
Steam Production Plant	108	PROD		CONSTANT
Nuclear Production Plant	108	PROD		CONSTANT
Hydraulic Production Plant	108	PROD		CONSTANT
Other Production Plant	108	PROD		CONSTANT
Transmission Plant	108	TRANS		CONSTANT
Distribution Plant	108	DIST		CONSTANT
General Plant	108	GP		CONSTANT
Amortization of Intangible Plant - Account 301	111	DIST		CONSTANT
Amortization of Intangible Plant - Account 302	111	DIRECT	PTD	CONSTANT
Amortization of Intangible Plant - Account 303	111	DIRECT	DIST	CONSTANT
Mining Plant Depreciation	108	PROD		CONSTANT
Amortization of Plant Held for Future Use	111	DIST		CONSTANT
Capital Lease - Common Plant	108	DIRECT	PTD	CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION
2008 Average System Cost Methodology
Functionalization and Escalation Codes

Account Description	Acct No.	Functionalization Codes		Escalation Codes
		Method	**Default**	
Leasehold Improvements	108	DIRECT	DIST	CONSTANT
In-Service: Depreciation of Common Plant	108	DIRECT	PTD	CONSTANT
Amortization of Other Utility Plant	108	DIRECT	DIST	CONSTANT
Amortization of Acquisition Adjustments	115	DIRECT	DIST	CONSTANT
Depreciation and Amortization Reserve (Other)		DIRECT	N/A	CONSTANT
Cash Working Capital:				
(Utility Plant) Held For Future Use	105	DIST		CONSTANT
(Utility Plant) Completed Construction - Not Classified	106	PTD		CONSTANT
Nuclear Fuel	120.2-120.6	PROD		NFUEL
Construction Work in Progress (CWIP)	107&120.1	DIST		CONSTANT
Common Plant		DIRECT	N/A	CONSTANT
Acquisition Adjustments (Electric)	114	DIRECT	DIST	CONSTANT
Other Property and Investments:				
Investment in Associated Companies	123.1	DIRECT	DIST	CONSTANT
Other Investment	124	DIST		CONSTANT
Long-Term Portion of Derivative Assets	175	DIST		CONSTANT
Long-Term Portion of Derivative Assets - Hedges	176	DIST		CONSTANT
Current and Accrued Assets:				
Fuel Stock	151	PROD		COAL
Fuel Stock Expenses Undistributed	152	PROD		CONSTANT
Plant Materials and Operating Supplies	154	PTD		INF
Merchandise (Major Only)	155	DIST		INF
Other Materials and Supplies (Major only)	156	DIST		INF
EPA Allowance Inventory	158.1	PROD		CONSTANT
EPA Allowances Withheld	158.2	PROD		CONSTANT
Stores Expense Undistributed	163	PTD		INF
Prepayments	165	PTD		CONSTANT
Derivative Instrument Assets	175	DIST		CONSTANT
Less: Long-Term Portion of Derivative Assets	175	DIST		CONSTANT
Derivative Instrument Assets – Hedges	176	DIST		CONSTANT
Less: Long-Term Portion of Derivative Assets - Hedges	176	DIST		CONSTANT
Deferred Debits:				
Unamortized Debt Expenses	181	PTDG		CONSTANT
Extraordinary Property Losses	182.1	DIRECT	DIST	CONSTANT
Unrecovered Plant and Regulatory Study Costs	182.2	DIRECT	DIST	CONSTANT
Other Regulatory Assets	182.3	DIRECT	DIST	CONSTANT
Preliminary Survey and Investigation Charges (Electric)	183	DIST		CONSTANT
Preliminary Natural Gas Survey and Investigation Charges	183.1	DIST		CONSTANT
Other Preliminary Survey and Investigation Charges	183.2	DIST		CONSTANT
Clearing Accounts	184	DIST		CONSTANT
Temporary Facilities	185	PTDG		CONSTANT
Miscellaneous Deferred Debits	186	DIRECT	DIST	CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2008 Average System Cost Methodology Functionalization and Escalation Codes				
Account Description	**Acct No.**	**Functionalization Codes**		**Escalation Codes**
		Method	**Default**	
Deferred Losses from Disposition of Utility Plant	187	DIRECT	N/A	CONSTANT
Research, Development, and Demonstration Expenditures	188	DIST		CONSTANT
Unamortized Loss on Reacquired Debt	189	PTDG		CONSTANT
Accumulated Deferred Income Taxes	190	DIST		CONSTANT
Liabilities and Other Credits (Comparative Balance Sheet):				
Derivative Instrument Liabilities	244	DIST		CONSTANT
Less: Long-Term Portion of Derivative Instrument Liabilities	244	DIST		CONSTANT
Derivative Instrument Liabilities – Hedges	245	DIST		CONSTANT
Less: Long-Term Portion of Derivative Inst Liabilities–Hedges	245	DIST		CONSTANT
Customer Advances for Construction	252	DIST		CONSTANT
Other Deferred Credits	253	DIRECT	DIST	CONSTANT
Other Regulatory Liabilities	254	DIRECT	DIST	CONSTANT
Accumulated Deferred Investment Tax Credits	255	DIST		CONSTANT
Deferred Gains from Disposition of Utility Plant	256	DIRECT	N/A	CONSTANT
Unamortized Gain on Reacquired Debt	257	PTDG		CONSTANT
Accumulated Deferred Income Taxes-Accel. Amort.	281	DIST		CONSTANT
Accumulated Deferred Income Taxes-Property	282	DIST		CONSTANT
Accumulated Deferred Income Taxes-Other	283	DIST		CONSTANT
Schedule 3: Expenses				
Power Production Expenses:				
Steam Power Generation				
Steam Power – Fuel	501	PROD		COAL
Steam Power - Operations (Excluding 501 - Fuel)	500-509	PROD		SOPS
Steam Power – Maintenance	510-515	PROD		SMN
Nuclear Power Generation				
Nuclear – Fuel	518	PROD		NFUEL
Nuclear - Operation (Excluding 518 - Fuel)	517-525	PROD		NOPS
Nuclear – Maintenance	528-532	PROD		NMN
Hydraulic Power Generation				
Hydraulic – Operation	535-540.1	PROD		HOPS
Hydraulic – Maintenance	541-545.1	PROD		HMN
Other Power Generation				
Other Power – Fuel	547	PROD		NATGAS
Other Power - Operations (Excluding 547 - Fuel)	546-550.1	PROD		OOPS
Other Power – Maintenance	551-554.1	PROD		OMN
Other Power Supply Expenses				
Purchased Power (Excluding REP Reversal)	555	PROD		CONSTANT
System Control and Load Dispatching	556	PROD		CONSTANT
Other Expenses	557	PROD		CONSTANT
BPA REP Reversal	555	PROD		CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2008 Average System Cost Methodology Functionalization and Escalation Codes				
Account Description	**Acct No.**	**Functionalization Codes**		**Escalation Codes**
		Method	**Default**	
Public Purpose Charges		DIRECT		CONSTANT
Transmission Expenses:				
Transmission of Electricity by Others (Wheeling)	565	TRANS		INF
Total Operations less Wheeling	560-567.1	TRANS		TOPS
Total Maintenance	568-574	TRANS		TMN
Distribution Expense:				
Total Operations	580-589	DIST		DOPS
Total Maintenance	590-598	DIST		DMN
Customer and Sales Expenses:				
Total Customer Accounts	901-905	DIST		CACNT
Customer Service and Information	906-907	DIST		CSERV
Customer assistance expenses (Major only)	908	DIRECT	N/A	CSERV
Customer Service and Information	909-910	DIST		CSALES
Total Sales Expense	911-917	DIST		CSALES
Administration and General Expense:				
Operation				
Administration and General Salaries	920	LABOR		A&G
Office Supplies & Expenses	921	LABOR		A&G
(Less) Administration Expenses Transferred - Credit	922	LABOR		A&G
Outside Services Employed	923	LABOR		A&G
Property Insurance	924	PTDG		A&G
Injuries and Damages	925	LABOR		A&G
Employee Pensions & Benefits	926	LABOR		A&G
Franchise Requirements	927	DIST		A&G
Regulatory Commission Expenses	928	DIST		A&G
(Less) Duplicate Charges - Credit	929	PTDG		A&G
General Advertising Expenses	930.1	DIRECT	DIST	A&G
Miscellaneous General Expenses	930.2	DIST		A&G
Rents	931	DIST		A&G
Transportation Expenses (Non Major)	933	DIST		A&G
Maintenance				
Maintenance of General Plant	935	GPM		A&G
Depreciation and Amortization:				
Amortization of Intangible Plant - Account 301	404	DIST		CONSTANT
Amortization of Intangible Plant - Account 302	404	DIRECT	PTD	CONSTANT
Amortization of Intangible Plant - Account 303	404	DIRECT	DIST	CONSTANT
Steam Production Plant	403	PROD		CONSTANT
Nuclear Production Plant	403	PROD		CONSTANT
Hydraulic Production Plant - Conventional	403	PROD		CONSTANT
Hydraulic Production Plant - Pumped Storage	403	PROD		CONSTANT
Other Production Plant	403	PROD		CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2008 Average System Cost Methodology Functionalization and Escalation Codes				
Account Description	**Acct No.**	**Functionalization Codes**		**Escalation Codes**
		Method	**Default**	
Transmission Plant	403	TRANS		CONSTANT
Distribution Plant	403	DIST		CONSTANT
General Plant	403	GP		CONSTANT
Common Plant - Electric	403 & 404	DIRECT	N/A	CONSTANT
Depreciation Expense for Asset Retirement Costs	403.1	DIRECT	N/A	CONSTANT
Amortization of Limited Term Electric Plant	404	DIRECT	N/A	CONSTANT
Amortization of Plant Acquisition Adjustments (Electric)	406	DIRECT	N/A	CONSTANT
Schedule 3A: Taxes				
FEDERAL:				
Income Tax (Included on Schedule 2)	409.1	DIST		CONSTANT
Employment Tax	408.1	LABOR		WAGES
Other Federal Taxes	408.1	DIST		CONSTANT
STATE AND OTHER:				
Property (or In-Lieu)	408.1	PTDG		CONSTANT
Unemployment	408.1	LABOR		WAGES
State Income, B&O, etc.	409.1	DIST		CONSTANT
Franchise Fees	408.1	DIST		CONSTANT
Regulatory Commission	408.1	DIST		CONSTANT
City/Municipal	408.1	DIST		CONSTANT
Other	408.1	DIST		CONSTANT
Schedule 3B: Other Included Items				
Other Included Items:				
Regulatory Debits	407.3	DIRECT	DIST	CONSTANT
Regulatory Credits	407.4	DIRECT	PROD	CONSTANT
Gain from Disposition of Utility Plant	411.6	DIRECT	PROD	CONSTANT
Loss from Disposition of Utility Plant	411.7	DIRECT	DIST	CONSTANT
Gain from Disposition of Allowances	411.8	PROD		CONSTANT
Loss from Disposition of Allowances	411.9	PROD		CONSTANT
Miscellaneous Nonoperating Income	421	DIRECT	PROD	CONSTANT
Sale for Resale:				
Sales for Resale	447	PROD		CONSTANT
Other Revenues:				
Forfeited Discounts	450	DIST		CONSTANT
Miscellaneous Service Revenues	451	DIST		CONSTANT
Sales of Water and Water Power	453	PROD		CONSTANT
Rent from Electric Property	454	TD		CONSTANT
Interdepartmental Rents	455	DIST		CONSTANT
Other Electric Revenues	456	DIRECT	PROD	CONSTANT
Revenues from Transmission of Electricity of Others	456.1	TRANS		CONSTANT
Labor Ratios				
Labor Ratio Input:				
Production		PROD		WAGES

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2008 Average System Cost Methodology Functionalization and Escalation Codes				
Account Description	**Acct No.**	**Functionalization Codes**		**Escalation Codes**
		Method	**Default**	
Transmission		TRANS		WAGES
Distribution		DIST		WAGES
Customer Accounts		DIST		WAGES
Customer Service and Informational		DIST		WAGES
Sales		DIST		WAGES
Administrative & General		PTD		WAGES

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Appendix 1
ASC Utility Filing Template

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BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Intangible Plant:								
Intangible Plant - Organization	204-207	301	DIST			-	-	-
Intangible Plant - Franchises and Consents	204-207	302	DIRECT	PTD		-	-	-
Intangible Plant - Miscellaneous	204-207	303	DIRECT	DIST		-	-	-
Total Intangible Plant					$ -	$ -	$ -	$ -
Production Plant:								
Steam Production	204-207	310-317	PROD			-	-	-
Nuclear Production	204-207	320-326	PROD			-	-	-
Hydraulic Production	204-207	330-337	PROD			-	-	-
Other Production	204-207	340-347	PROD			-	-	-
Total Production Plant					$ -	$ -	$ -	$ -
Transmission Plant: (i)								
Transmission Plant	204-207	350-359.1	TRANS			-	-	-
Total Transmission Plant					$ -	$ -	$ -	$ -
Distribution Plant:								
Distribution Plant	204-207	360-374	DIST			-	-	-
Total Distribution Plant					$ -	$ -	$ -	$ -
General Plant:								
Land and Land Rights	204-207	389	PTD			-	-	-
Structures and Improvements	204-207	390	PTD			-	-	-
Furniture and Equipment	204-207	391	LABOR			-	-	-
Transportation Equipment	204-207	392	TD			-	-	-
Stores Equipment	204-207	393	PTD			-	-	-
Tools and Garage Equipment	204-207	394	PTD			-	-	-
Laboratory Equipment	204-207	395	PTD			-	-	-
Power Operated Equipment	204-207	396	TD			-	-	-
Communication Equipment	204-207	397	PTD			-	-	-
Miscellaneous Equipment	204-207	398	PTD			-	-	-
Other Tangible Property	204-207	399	DIRECT	PTD		-	-	-
Asset Retirement Costs for General Plant	204-208	399.1	PTD			-	-	-
Total General Plant					$ -	$ -	$ -	$ -
Total Electric Plant In-Service					$ -	$ -	$ -	$ -

(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)

Page A3
Appendix 1

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
LESS:								
Depreciation and Amortization Reserve								
Steam Production Plant	219	108	PROD			-	-	-
Nuclear Production Plant	219	108	PROD			-	-	-
Hydraulic Production Plant	219	108	PROD			-	-	-
Other Production Plant	219	108	PROD			-	-	-
Transmission Plant (i)	219	108	TRANS			-	-	-
Distribution Plant	219	108	DIST			-	-	-
General Plant	219	108	GP			-	-	-
Amortization of Intangible Plant - Account 301	219	111	DIST			-	-	-
Amortization of Intangible Plant - Account 302	219	111	DIRECT	PTD		-	-	-
Amortization of Intangible Plant - Account 303	219	111	DIRECT	DIST		-	-	-
Mining Plant Depreciation	219	108	PROD			-	-	-
Amortization of Plant Held for Future Use	219	111	DIST			-	-	-
Capital Lease - Common Plant	219	108	DIRECT	PTD		-	-	-
Leasehold Improvements	200-201	108	DIRECT	DIST		-	-	-
In-Service: Depreciation of Common Plant (a)	200-201	108	DIRECT	PTD		-	-	-
Amortization of Other Utility Plant (a)	200-201	108	DIRECT	DIST		-	-	-
Amortization of Acquisition Adjustments	200-201	115	DIRECT	DIST		-	-	-
Depreciation and Amortization Reserve (Other)			DIRECT					
Total Depreciation and Amortization Reserve					$ -	$ -	$ -	$ -
Total Net Plant					$ -	$ -	$ -	$ -
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)								

Page A4
Appendix 1

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Assets and Other Debits (Comparative Balance Sheet)								
Cash Working Capital (f)	Calculation				0	-	-	-
Utility Plant								
(Utility Plant) Held For Future Use	200-201	105	DIST			-	-	-
(Utility Plant) Completed Construction - Not Classified	200-201	106	PTD			-	-	-
Nuclear Fuel		120.2-120.6	PROD			-	-	-
Construction Work in Progress (CWIP)	200-201	107 & 120.1	DIST			-	-	-
Common Plant	356 & 356.1		DIRECT					
Acquisition Adjustments (Electric)	200-201	114	DIRECT	DIST		-	-	-
Total					$ -	$ -	$ -	$ -
Other Property and Investments								
Investment in Associated Companies	110-111	123.1	DIST	DIST		-	-	-
Other Investment	110-111	124	DIST			-	-	-
Long-Term Portion of Derivative Assets	110-111	175	DIST			-	-	-
Long-Term Portion of Derivative Assets - Hedges	110-111	176	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Current and Accrued Assets								
Fuel Stock	110-111	151	PROD			-	-	-
Fuel Stock Expenses Undistributed	110-111	152	PROD			-	-	-
Plant Materials and Operating Supplies	110-111	154	PTD			-	-	-
Merchandise (Major Only)	110-112	155	DIST			-	-	-
Other Materials and Supplies (Major only)	110-111	156	DIST			-	-	-
EPA Allowance Inventory	110-112	158.1	PROD			-	-	-
EPA Allowances Withheld	110-112	158.2	PROD			-	-	-
Stores Expense Undistributed	110-111	163	PTD			-	-	-
Prepayments	110-111	165	PTD			-	-	-
Derivative Instrument Assets	110-111	175	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets	110-112	175	DIST			-	-	-
Derivative Instrument Assets - Hedges	110-111	176	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets - Hedges	110-112	176	DIST			-	-	-
Total					$ -	$ -	$ -	$ -

Page A5
Appendix 1

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Deferred Debits								
Unamortized Debt Expenses	110-111	181	PTDG			-	-	-
Extraordinary Property Losses	110-111	182.1	DIRECT	DIST		-	-	-
Unrecovered Plant and Regulatory Study Costs	110-111	182.2	DIRECT	DIST		-	-	-
Other Regulatory Assets	110-111	182.3	DIRECT	DIST		-	-	-
Preliminary Survey and Investigation Charges (Electric)	110-111	183	DIST			-	-	-
Preliminary Natural Gas Survey and Investigation Charges	110-111	183.1	DIST			-	-	-
Other Preliminary Survey and Investigation Charges	110-111	183.2	DIST			-	-	-
Clearing Accounts	110-111	184	DIST			-	-	-
Temporary Facilities	110-111	185	PTDG			-	-	-
Miscellaneous Deferred Debits	110-111	186	DIRECT	DIST		-	-	-
Deferred Losses from Disposition of Utility Plant	110-111	187	DIRECT					
Research, Development, and Demonstration Expenditures	110-111	188	DIST			-	-	-
Unamortized Loss on Reacquired Debt	110-111	189	PTDG			-	-	-
Accumulated Deferred Income Taxes	110-111	190	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Total Assets and Other Debits					$ -	$ -	$ -	$ -

Page A6
Appendix 1

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Liabilities and Other Credits (Comparative Balance Sheet)								
Current and Accrued Liabilites								
Derivative Instrument Liabilities	112-113	244	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities	112-114	244	DIST			-	-	-
Derivative Instrument Liabilities - Hedges	112-115	245	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges	112-114	245	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Deferred Credits								
Customer Advances for Construction	112-113	252	DIST			-	-	-
Other Deferred Credits	112-113	253	DIRECT	DIST		-	-	-
Other Regulatory Liabilities	112-113	254	DIRECT	DIST		-	-	-
Accumulated Deferred Investment Tax Credits	112-113	255	DIST			-	-	-
Deferred Gains from Disposition of Utility Plant	112-113	256	DIRECT					
Unamortized Gain on Reacquired Debt	112-113	257	PTDG			-	-	-
Accumulated Deferred Income Taxes-Accel. Amort.	112-113	281	DIST			-	-	-
Accumulated Deferred Income Taxes-Property	112-113	282	DIST			-	-	-
Accumulated Deferred Income Taxes-Other	112-113	283	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Total Liabilities and Other Credits					$ -	$ -	$ -	$ -
Total Rate Base					$ -	$ -	$ -	$ -
Total Net Plant + (Assets and Others Debits) - (Liabilities and Other Credits)								

Page A7
Appendix 1

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 1A: Cash Working Capital (f)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	-	-	-	-
Total Transmission O&M (i)	-	-	-	-
Total Distribution O&M	-	-	-	-
Total Customer & Sales	-	-	-	-
Total Administrative and General O&M	-	-	-	-
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs	-	-	-	-
Revised Total O&M Expenses	$ -	$ -	$ -	$ -
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 2: Capital Structure and Rate of Return (b)

SUMMARY *(for use by ASC Forecast Model)*

Single-Jurisdiction Investor-Owned Utility Return Calculation:

Multi-Jurisdiction Investor-Owned Utility Return Calculation:

Consumer-Owned Utility Return Calculation:

Rate of Return :

Single-Jurisdiction Investor-Owned Utility Return Calculation

Step 1: Weighted Cost of Capital from Most Recent State Commission Rate Order

Note: Multi-jurisdictional utilities must begin on Page 2

Publicly-owned utilities must begin on Page 4

	Capitalization Structure		Effective Cost	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**
Debt				
Preferred Equity				
Common Equity				
Weighted Cost of Capital	$ -			

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%) 35%

Federal Income Tax Factor

*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*

Federal Income Tax Adjusted Weighted Cost of Capital

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ -	$ -	$ -	$ -
Federal Income Tax Adjusted Weighted Cost of Capital				
Federal Income Tax Adjusted Return on Rate Base				

*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 2: Capital Structure and Rate of Return (b)

Multi-Jurisdiction Investor-Owned Utility Return Calculation

Step 1:

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 1

	Capitalization Structure		Effective Cost		Jurisdictional	Effective Cost -	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**	**Allocation**	**Weighted State Allocation**	
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 2

Component	**Amount**	**Percent**	**Embedded**	**Weighted**			
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 3

Component	**Amount**	**Percent**	**Embedded**	**Weighted**			
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Jurisdiction	**Rate Base**	**Weighted cost**	**%**	**Weighted Return**		
Total						

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 2: Capital Structure and Rate of Return (b)

Multi-Jurisdiction Investor-Owned Utility Return Calculation *(continued)*

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%)	**35%**	
Federal Income Tax Factor *{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*		
Federal Income Tax Adjusted Weighted Cost of Capital *(Weighted Cost of Capital Plus Federal Income Tax Factor)*		

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ -	$ -	$ -	$ -
Federal Income Tax Adjusted Weighted Cost of Capital				
Federal Income Tax Adjusted Return on Rate Base *(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*				

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 2: Capital Structure and Rate of Return (b)

Consumer-Owned Utility Return Calculation

Step 1: Weighted Cost of Debt

	Original	Year	Year	Interest	Interest
Debt Issue	Amount	Issued	Due	Rate	Expense
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
Weighted Cost of Debt	$ -				$ -

Step 2: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ -	$ -	$ -	$ -
Weighted Cost of Debt				
Return on Rate Base				

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Power Production Expenses:								
Steam Power Generation								
Steam Power - Fuel	320-323	501	PROD			-	-	-
Steam Power - Operations (Excluding 501 - Fuel)	320-323	500-509	PROD			-	-	-
Steam Power - Maintenance	320-323	510-515	PROD			-	-	-
Nuclear Power Generation								
Nuclear - Fuel	320-323	518	PROD			-	-	-
Nuclear - Operation (Excluding 518 - Fuel)	320-323	517-525	PROD			-	-	-
Nuclear - Maintenance	320-323	528-532	PROD			-	-	-
Hydraulic Power Generation								
Hydraulic - Operation	320-323	535-540.1	PROD			-	-	-
Hydraulic - Maintenance	320-323	541-545.1	PROD			-	-	-
Other Power Generation								
Other Power - Fuel	320-323	547	PROD			-	-	-
Other Power - Operations (Excluding 547 - Fuel)	320-323	546-550.1	PROD			-	-	-
Other Power - Maintenance	320-323	551-554.1	PROD			-	-	-
Other Power Supply Expenses								
Purchased Power (Excluding REP Reversal)	326	555	PROD		0	-	-	-
System Control and Load Dispatching	320-323	556	PROD			-	-	-
Other Expenses	320-323	557	PROD			-	-	-
BPA REP Reversal	327	555	PROD			-	-	-
Public Purpose Charges (a) (h)			DIRECT					
Total Production Expense					$ -	$ -	$ -	$ -
Transmission Expenses: (i)								
Transmission of Electricity by Others (Wheeling)	320-323	565	TRANS			-	-	-
Total Operations less Wheeling	320-323	560-567.1	TRANS			-	-	-
Total Maintenance	320-323	568-574	TRANS			-	-	-
Total Transmission Expense					$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Distribution Expense:								
Total Operations	320-323	580-589	DIST			-	-	-
Total Maintenance	320-323	590-598	DIST			-	-	-
Total Distribution Expense					$ -	$ -	$ -	$ -
Customer and Sales Expenses:								
Total Customer Accounts	320-323	901-905	DIST			-	-	-
Customer Service and Information	320-323	906-907	DIST			-	-	-
Customer Assistance Expenses (Major only)	320-323	908	DIRECT					
Customer Service and Information	320-323	909-910	DIST			-	-	-
Total Sales Expense	320-323	911-917	DIST			-	-	-
Total Customer and Sales Expenses					$ -	$ -	$ -	$ -
Administration and General Expense:								
Operation								
Administration and General Salaries	320-323	920	LABOR			-	-	-
Office Supplies & Expenses	320-323	921	LABOR			-	-	-
(Less) Administration Expenses Transferred - Credit	320-323	922	LABOR			-	-	-
Outside Services Employed (g)	320-323	923	LABOR			-	-	-
Property Insurance	320-323	924	PTDG			-	-	-
Injuries and Damages	320-323	925	LABOR			-	-	-
Employee Pensions & Benefits	320-323	926	LABOR			-	-	-
Franchise Requirements	320-323	927	DIST			-	-	-
Regulatory Commission Expenses	320-323	928	DIST			-	-	-
(Less) Duplicate Charges - Credit	320-323	929	PTDG			-	-	-
General Advertising Expenses (g)	320-323	930.1	DIST	DIST		-	-	-
Miscellaneous General Expenses	320-323	930.2	DIST			-	-	-
Rents	320-323	931	DIST			-	-	-
Transportation Expenses (Non Major)	320-324	933	DIST			-	-	-
Maintenance								
Maintenance of General Plant	320-323	935	GPM			-	-	-
Total Administration and General Expenses					$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Total Operations and Maintenance					$ -	$ -	$ -	$ -
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)								
Depreciation and Amortization:								
Amortization of Intangible Plant - Account 301	336	404	DIST			-	-	-
Amortization of Intangible Plant - Account 302	336	404	DIRECT	PTD		-	-	-
Amortization of Intangible Plant - Account 303	336	404	DIRECT	DIST		-	-	-
Steam Production Plant	336	403	PROD			-	-	-
Nuclear Production Plant	336	403	PROD			-	-	-
Hydraulic Production Plant - Conventional	336	403	PROD			-	-	-
Hydraulic Production Plant - Pumped Storage	336	403	PROD			-	-	-
Other Production Plant	336	403	PROD			-	-	-
Transmission Plant (i)	336	403	TRANS			-	-	-
Distribution Plant	336	403	DIST			-	-	-
General Plant	336	403	GP			-	-	-
Common Plant - Electric	336	403	DIRECT					
Common Plant - Electric	336	404	DIRECT					
Depreciation Expense for Asset Retirement Costs	336	403.1	DIRECT					
Amortization of Limited Term Electric Plant	336	404	DIRECT					
Amortization of Plant Acquisition Adjustments (Electric)	200-201	406	DIRECT					
Total Depreciation and Amortization					$ -	$ -	$ -	$ -
Total Operating Expenses					$ -	$ -	$ -	$ -
(Total O&M + Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINSTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

FERC Form 1		Purchased Power - Base Period		Purchased Power - Base Period Minus 1		Purchased Power - Base Period Minus 2	
Statistical Classification	Page Number	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased
RQ	326-327						
LF	326-327						
IF	326-327						
SF	326-327						
LU	326-327						
IU	326-327						
OS	326-327						
EX	326-327						
NA	326-327						
AD	326-327						
TOTAL		$ -	-	$ -	-	$ -	-

FERC Form 1		Sales for Resale - Base Period		Sales for Resale - Base Period Minus 1		Sales for Resale - Base Period Minus 2	
Statistical Classification	Page Number	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased
RQ	310-311						
LF	310-311						
IF	310-311						
SF	310-311						
LU	310-311						
IU	310-311						
OS	310-311						
EX	310-311						
NA	310-311						
AD	310-311						
TOTAL		$ -	-	$ -	-	$ -	-

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 3A Items: Taxes

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Funct. Method	Total	Production	Transmission	Distribution/ Other
FEDERAL							
Income Tax	262	409.1	DIST		-	-	-
Employment Tax	262	408.1	LABOR		-	-	-
Other Federal Taxes	262	408.1	DIST		-	-	-
TOTAL FEDERAL				$ -	$ -	$ -	$ -
STATE AND OTHER							
Property or In-Lieu (c)	262	408.1	PTDG		-	-	-
Unemployment	262	408.1	LABOR		-	-	-
State Income, B&O, etc.	262	409.1	DIST		-	-	-
Franchise Fees	262	408.1	DIST		-	-	-
Regulatory Commission	262	408.1	DIST		-	-	-
City/Municipal	262	408.1	DIST		-	-	-
Other	262	408.1	DIST		-	-	-
TOTAL STATE AND OTHER TAXES				$ -	$ -	$ -	$ -
TOTAL TAXES				$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3B Other Included Items (j)

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Other Included Items:								
Regulatory Credits	114	407.4	DIRECT	PROD		-	-	-
(Less) Regulatory Debits	114	407.3	DIRECT	DIST		-	-	-
Gain from Disposition of Utility Plant	114	411.6	DIRECT	PROD		-	-	-
(Less) Loss from Disposition of Utility Plant	114	411.7	DIRECT	DIST		-	-	-
Gain from Disposition of Allowances	114	411.8	PROD			-	-	-
(Less) Loss from Disposition of Allowances	114	411.9	PROD			-	-	-
Miscellaneous Nonoperating Income	114	421	DIRECT	PROD		-	-	-
Total Other Included Items					$ -	$ -	$ -	$ -
Sales for Resale:								
Sales for Resale	310	447	PROD		-	-	-	-
Total Sales for Resale					$ -	$ -	$ -	$ -
Other Revenues:								
Forfeited Discounts	300	450	DIST			-	-	-
Miscellaneous Service Revenues	300	451	DIST			-	-	-
Sales of Water and Water Power	300	453	PROD			-	-	-
Rent from Electric Property	300	454	TD			-	-	-
Interdepartmental Rents	300	455	DIST			-	-	-
Other Electric Revenues	300	456	DIRECT	PROD		-	-	-
Revenues from Transmission of Electricity of Others (i)	330	456.1	TRANS			-	-	-
Total Other Revenues					$ -	$ -	$ -	$ -
Total Other Included Items					$ -	$ -	$ -	$ -

(Total Other + Total Sales for Resale + Total Other Revenue)

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BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 4: Average System Cost

	Total	Production	Transmission	Distribution/Other
Total Operating Expenses *(From Schedule 3)*	$ -	$ -	$ -	$ -
Federal Income Tax Adjusted Return on Rate Base *(From Schedule 2)*	$ -	$ -	$ -	$ -
State and Other Taxes *(From Schedule 3a)*	$ -	$ -	$ -	$ -
Total Other Included Items *(From Schedule 3b)*	$ -	$ -	$ -	$ -
Total Cost	**$ -**	**$ -**	**$ -**	**$ -**

(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 4: Average System Cost

Contract System Cost	
Production	$ -
Transmission	$ -
(Less) New Large Single Load Costs (d)	
Total Contract System Cost	**$ -**
Contract System Load (MWh)	
Total Retail Load	
(Less) New Large Single Load	
Total Retail Load (Net of NLSL) (d)	0
Distribution Loss (e)	0
Total Contract System Load	**0**
Average System Cost $/MWh	**$0**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Distribution of Salaries and Wages (For Labor Ratio Calculation)

Description	Form 1 Page Number	Amount
Electric		
Operation		
Production	354-355	
Transmission	354-355	
Distribution	354-355	
Customer Accounts	354-355	
Customer Service and Information	354-355	
Sales	354-355	
Administrative and General	354-355	
TOTAL Operation		**$0**
Maintenance		
Production	354-355	
Transmission	354-355	
Distribution	354-355	
Administrative and General	354-355	
TOTAL Maintenance		**$0**
Operation and Maintenance		
Production (Total of lines 16 and 26)	354-355	0
Transmission (Total of lines 17 and 27)	354-355	0
Distribution (Total of lines 18 and 28)	354-355	0
Customer Accounts (From line 20)	354-355	0
Customer Service and Information (From line 20)	354-355	0
Sales (From line 21)	354-355	0
Administrative and General (Total of lines 22 and 29)	354-355	0
TOTAL Operation and Maintenance		**$0**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Ratio Table

Labor Ratio Input:	Ratio Used	Total	Production	Transmission	Distribution
Production	PROD	$ -	$ -	$ -	$ -
Transmission	TRANS	-	-	-	-
Distribution	DIST	-	-	-	-
Customer Accounts	DIST	-	-	-	-
Customer Service and Informational	DIST	-	-	-	-
Sales	DIST	-	-	-	-
Administrative & General	PTD	-	-	-	-
Total Labor		$ -	$ -	$ -	$ -
LABOR RATIO		**0%**	**0%**	**0%**	**0%**

GP **General Plant Ratio**	Ratio Used	Total	Production	Transmission	Distribution
Land and Land Rights	PTD	$ -	$ -	$ -	$ -
Structures and Improvements	PTD	-	-	-	-
Furniture and Equipment	LABOR	-	-	-	-
Transportation Equipment	TD	-	-	-	-
Stores Equipment	PTD	-	-	-	-
Tools and Garage Equipment	PTD	-	-	-	-
Laboratory Equipment	PTD	-	-	-	-
Power Operated Equipment	TD	-	-	-	-
Communication Equipment	PTD	-	-	-	-
Miscellaneous Equipment	PTD	-	-	-	-
Other Tangible Property	DIRECT	-	-	-	-
Asset Retirement Costs for General Plant	PTD	-	-	-	-
TOTAL		$ -	$ -	$ -	$ -
GP RATIO		**0%**	**0%**	**0%**	**0%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Ratio Table

PTD	Production, Transmission, Distribution Ratio	Ratio Used	Total	Production	Transmission	Distribution
	Steam Production	PROD	$ -	$ -	$ -	$ -
	Nuclear Production	PROD	-	-	-	-
	Hydraulic Production	PROD	-	-	-	-
	Other Production	PROD	-	-	-	-
	Total Production Plant		-	-	-	-
	Transmission Plant	TRANS	-	-	-	-
	Total Distribution Plant	DIST	-	-	-	-
	TOTAL		$ -	$ -	$ -	$ -
	PTD RATIO		**0%**	**0%**	**0%**	**0%**

PTDG	Production, Transmission, Distribution and General Plant Rati	Ratio Used	Total	Production	Transmission	Distribution
	PTD Total		$ -	$ -	$ -	$ -
	Intangible Plant - Organization	DIST	-	-	-	-
	Intangible Plant - Franchises and Consents	DIRECT	-	-	-	-
	Intangible Plant - Miscellaneous	DIRECT	-	-	-	-
	General Plant Total		-	-	-	-
	TOTAL		$ -	$ -	$ -	$ -
	PTDG RATIO		**0%**	**0%**	**0%**	**0%**

TD	Transmission and Distribution Plant Ratio	Ratio Used	Total	Production	Transmission	Distribution
	Total Transmission Plant	TRANS	$ -	$ -	$ -	$ -
	Total Distribution Plant	DIST	-	-	-	-
	TOTAL		$ -	$ -	$ -	$ -
	TD RATIO		**0%**	**0%**	**0%**	**0%**

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
GPM	**Maintenance of General Plant Ratio**					
	Structures and Improvements	PTD	$ -	$ -	$ -	$ -
	Furniture and Equipment	LABOR	-	-	-	-
	Communication Equipment	PTD	-	-	-	-
	Miscellaneous Equipment	PTD	-	-	-	-
	TOTAL		$ -	$ -	$ -	$ -
	GPM RATIO		0%	0%	0%	0%

SUMMARY RATIO TABLE

Direct to Distribution	**DIST**	**0.00%**	**0.00%**	**100.00%**
Direct to Production	**PROD**	**100.00%**	**0.00%**	**0.00%**
Direct to Transmission	**TRANS**	**0.00%**	**100.00%**	**0.00%**
Direct Allocation	**DIRECT**	**0.00%**	**0.00%**	**0.00%**
General Plant	**GP**	**0.00%**	**0.00%**	**0.00%**
Maintenance of General Plant	**GPM**	**0.00%**	**0.00%**	**0.00%**
Labor Ratios	**LABOR**	**0.00%**	**0.00%**	**0.00%**
Production, Transmission, Distribution	**PTD**	**0.00%**	**0.00%**	**0.00%**
Production, Transmission, Distribution, General	**PTDG**	**0.00%**	**0.00%**	**0.00%**
Transmission, Distribution	**TD**	**0.00%**	**0.00%**	**0.00%**

IX. AVERAGE SYSTEM COST METHODOLOGY APPENDIX 1 ENDNOTES

a/ Contract System Costs shall reflect the costs and the revenues arising from conservation and/or retail rate schedules.

b/ The overall rate of return (ROR) to be applied to a Utility's Exchange Period rate base as shown in Appendix 1 shall be equal to its weighted cost of capital (WCC), including debt, preferred stock and equity, from its most recently approved Regulatory Body Rate Order. For multi-Jurisdictional Utilities, a Utility will first determine the WCC for each Jurisdiction. The Utility will then determine a region-wide WCC based on applying the WCC times the Regulatory Body approved rate base from the same rate order used for the WCC.

The ROE used in the WCC calculation will then be grossed up for Federal income taxes at the marginal Federal income tax rate using the following formula to determine the percentage increase in the ROE used for ASC determination:
FIT Adder = {(WCC – (Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1-Federal Tax Rate)}

The sum of the FIT Adder plus the ROE equals the Federal income tax adjusted ROE (TAROE). The TAROE will replace the ROE in the WCC calculation to determine a Federal income tax adjusted weighted cost of capital (TAWCC). The TAWCC will be multiplied by the total rate base from Schedule 1 to determine the return component on Schedule 2.

For Utilities that do not use depreciation for Jurisdictional rate setting, the return will be equal to the weighted cost of debt times the rate base included in the ASC filing.

c/ A tax-exempt Utility may include in-lieu taxes up to an amount that is comparable, for each unit of government paid in-lieu taxes, with taxes that would have been paid by a non-tax exempt utility to that unit of government. In no event shall the Utility's regional total be greater than the actual amount paid or the amount used to determine the total revenue requirement. In-lieu taxes shall be functionalized according to the PTDG ratio.

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 NR 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 NR 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 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.

The above three paragraphs shall determine the Base Period cost of resources used to serve NLSLs. BPA will escalate the Base Period cost of resources used to serve NLSLs to the Exchange Period using the following steps:

i. Escalate the components of the Base Period fully allocated resource costs to the Exchange Period using the general method for escalation of all Base Period costs.

ii. Adjust the projected resource costs by the projected transmission costs.

iii. Add the fully allocated costs for major resource additions/retirements to the Exchange Period fully allocated costs.

iv. The cost to serve NLSLs will change when the ASC changes due to resource additions/retirements.

v. The Exchange Period NLSL load will equal the Base Period NLSL load.

e/ The losses shall be the distribution energy losses occurring between the transmission portion of the Utility's system and the meters measuring firm energy load. The distribution loss can be measured using one of the following 3 methods:

Method 1, Distribution Loss Study: Losses shall be established according to a study (engineering, statistical and other) that is submitted to BPA by the Utility which will be subject to review by BPA. This study shall be in sufficient detail so as to accurately identify average distribution losses associated with the Utility's total load, excluded loads, and the residential load. Distribution losses shall include losses associated with distribution substations, primary distribution facilities, distribution transformers, secondary distribution facilities and service drops.

Method 2, Revenue Grade Meters: If a Utility does not have a loss study, but it has sufficient revenue grade meters in its distribution system, BPA will permit the Utility to directly measure its distribution losses subject to BPA review and approval. A Utility that does not possess the capability to directly measure its distribution losses will be required to submit a distribution loss study every seven years.

Method 3, Default: If a Utility does not have a current loss study or grade meters, BPA will accept the following method for determining a Utility's distribution loss factor.

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

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

iii. 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.

f/ Cash working capital (CWC) is a ratemaking convention that is not included in the Form 1, but a part of all electric utility rate filings as a component of rate base. For determining the allowable amount of cash working capital in rate base for a Utility, BPA will allow no more than 1/8 of the functionalized costs of total production expenses, transmission expenses and Administrative and General expenses less purchased power, fuel costs, and Public Purpose Charge.

g/ Conservation costs are costs of energy audits and actual or planned load reduction resulting from direct application of a conservation measure (Northwest Power Act, section 3(19)(B)) by means of physical improvements, alterations, devices, or other installations which are measurable in units. Conservation costs funded by the Utility will be functionalized to Production in the Utility's Average System Cost. Conservation costs incurred to promote changes in consumer behavior including costs attributable to brochures, advertising, pamphlets, leaflets, and similar items will be functionalized by Direct Analysis with a default to Distribution/Other. Conservation surcharges imposed pursuant to section 4(f)(2) of the Northwest Power Act or other similar surcharges or penalties imposed on a Utility for failure to meet required conservation efforts will also be functionalized to Distribution/Other. Conservation and associated costs must be generally consistent with the Council's resource plan as determined by the Administrator.

h/ Public Purpose Charges collected by Utilities and distributed to independent third party non-profit organizations or state and local entities (recipient organizations) for the purposes of acquiring conservation and renewable resources shall be determined on a utility-by-utility basis through Direct Analysis. The ASCM will only allow the costs of conservation and renewable resource development, acquisition and implementation. Allowable costs include costs associated with energy audits and advertising and promotion of conservation and renewable resources.

In order to be included in Contract System Costs, the renewable resources acquired by the recipient must be included in the Utility's Integrated Resource Plan or similar document and, in the case of dispatchable resources, must be included in the Utility's resource stack. BPA will treat expenditures of Public Purchase Charge funds similar to Utility conservation costs.

i/ If a Utility has a ruling from its Regulatory Body that separates its transmission and distribution lines using FERC's seven factor test contained in Order 888, and its Form 1 filing is consistent with the Regulatory Body's order, the Utility will include the transmission-related costs and wheeling revenues directly from its Form 1 filing. However, if a Utility is not required to file a Form 1, or it has not received an order from its Regulatory Body separating its lines between transmission and distribution, then it must perform a Direct Analysis on its transmission costs and wheeling revenues. The Direct Analysis must allocate transmission costs and wheeling revenues so that only the costs and revenues of transmission lines rated at 115kV or above are included as transmission. Alternatively, the Direct Analysis may use FERC's seven factor test for separating transmission and distribution lines to determine the costs attributable to transmission.

j/ All revenues associated with the production and transmission function of a Utility will be functionalized to production or transmission respectively.

Appendix 2
Chief Financial Officer Attestation

Exhibit A:
Statement of Review and Compilation of Work Performed

Exhibit B:
Financial Reporting Process and Attestation for IOUs and COUs

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Appendix 2
Chief Financial Officer Attestation

<<Customer’s Name>>
Average System Cost Filing
For the Base Period Beginning _______________, 20XX
And Ending _______________, 20XX

I, ____, having reviewed the Average System Cost (ASC) Appendix 1 Filing (ASC Filing) attached with this attestation, and in accordance with Exhibit A, *Statement of Review and Compilation of Work Performed*, of this Appendix 2, hereby certify that:

1. The ASC Filing has been prepared in accordance with Bonneville Power Administration’s current ASC Methodology.

2. The ASC Filing excludes the costs associated with: (a) the cost of additional resources in an amount sufficient to serve any New Large Single Load after September 1, 1979; (b) the cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after December 5, 1980; and (c) any costs of any generating facility which is terminated prior to initial commercial operation.

3. Based on my knowledge as <<Customer’s Name>>’s Chief Financial Officer, the ASC Filing is based on <<Customer’s Name>>’s audited financial statements, FERC Form 1 filings and/or Cost of Service Analysis (COSA), and other financial information, and fairly presents in all material respects the operating costs of the utility for ___________, 20XX through ___________, 20XX.

4. Based on my knowledge as <<Customer’s Name>>’s Chief Financial Officer, the ASC Filing omits no material facts and contains no false statement regarding any material facts.

Respectfully submitted,

Chief Financial Officer
<<Customer’s Name>>

Date:_____________________

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Exhibit A to Appendix 2
Statement of Review and Compilation of Work Performed

<<Customer's Name>>
Cost of Service Analysis Report
for the Base Period _______________, 20XX
through _______________, 20XX

This document is intended to be used by Engineering and Consulting Firms to provide; 1) a statement of the review work that was performed to ensure the accuracy and correctness of the information contained in the COSA report, and 2) to provide an assurance statement that the information contained in the COSA report is presented fairly in all material respects. Independent accounting firms would present similar information in their COSA compilation reports. The Appendix 1 references below simply denote where the financial and load data will ultimately appear in the Appendix 1 filing.

<u>Section 1</u> – Statement of the Work performed and procedures that were followed in preparing the Cost of Service Analysis (COSA).

Examples of work performed cited in the Statement of Work should include:

1. Reconciliation of (1) results of financial statement expense information with (2) data contained in the COSA report (ASC Filing, Appendix 1 - Schedule 3).
2. Reconciliation of (1) tax expense and amounts paid in-lieu of taxes to state and local governmental bodies per the financial statement expense information with (2) the tax expense information contained in the COSA report (ASC Filing, Appendix 1 - Schedule 3A).
3. Reconciliation of (1) revenue credits and other included items used to reduce the rates of the utility's native load customers contained in financial statement income information with (2) the information contained in the COSA report (ASC Filing, Appendix 1 - Schedule 3B).
4. Reconciliation of (1) cash and short-term investment financial statement account information with (2) working capital data contained in the COSA report (ASC Filing, Appendix 1 - Schedule 1A).
5. Plant investment costs, accumulated depreciation on plant investments and net un-depreciated plant investment at year end date is reconciled to the plant investment information contained in the COSA report. Plant investment costs associated with New Large Single Loads; generating assets used to serve loads outside of the Pacific Northwest region; and generating facilities that were terminated prior to commercial operation should be identified in separate accounts (ASC Filing, Appendix 1 - Schedule 1).
6. Long-term debt information (date bonds issued, original issue amount, principal balance at year end date, and interest rate of each bond issued along with a

weighted average cost of long-term debt outstanding) is reconciled to the information contained in the COSA report (ASC Filing, Appendix 1 – Sch. 2).

7. Return on plant investment calculation (net plant investment per Item 3 above times the weighted average cost of long-term debt per Item 4 above) is reconciled to the information contained in the COSA report.
8. Items 1-3 and 5-7 above are aggregated to produce the total cost of service amounts (aggregate costs have to be less than the projected costs contained in the utility's rates) and divided by annual customer loads (Item 9 below) to arrive at the utility's base period ASC.
9. Annual customer load information (annual megawatt hours) per the statistical section of the annual report is reconciled to the COSA report information.
10. Description of analytical procedures performed to gain additional assurance over the COSA report information. Comparison of current year information with prior year information, trend analysis, financial ratio analysis, and comparison of customer load information by segment with prior year load information.
11. Description of additional compilation and review procedures performed in preparing the COSA information.

Section 2 – Report Assurance

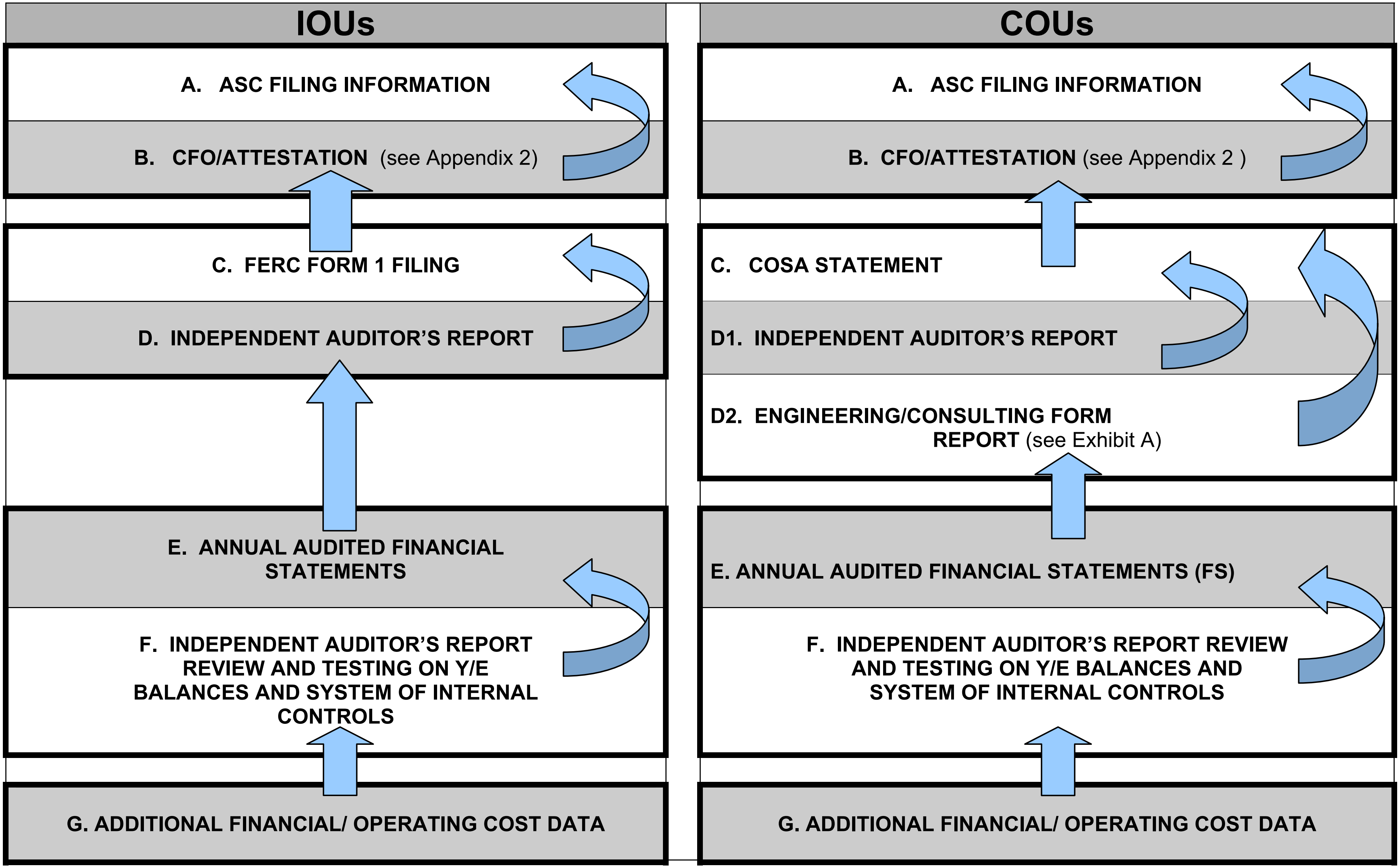
Based upon the audited financial statements of <<Customer's Name>> for the year ending ______________, 20XX, along with other financial statement and utility operating information provided to us, we have reviewed <<Customer's Name>>'s COSA report for the twelve month period ending __________. Our review included sufficient compilation review procedures along with additional analytical procedures to allow us to conclude that the information contained in the COSA report is presented fairly in all material respects.

Respectfully submitted,

____________________________, <<Title>>
<<Company Name>> Auditing, Engineering or Management Consulting Firm

Date:___________________

Exhibit B to Appendix 2
Financial Documentation Requirements and Attestations for IOUs and COUs



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BONNEVILLE POWER ADMINISTRATION
DOE/BP-3894 June 2008 1C