FY 2010-11 AVERAGE SYSTEM COST
DRAFT REPORT

FOR

PacifiCorp

Docket Number: ASC-10-PA-01
Effective Date: October 1, 2009

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

April 13, 2009

This page intentionally left blank.

TABLE OF CONTENTS

Section **Page**

List of Tables

This page intentionally left blank.

1. FILING DATA

Utility: **PacifiCorp**
825 NE Multnomah
Portland, OR 97232
http://www.pacificorp.com

Parties to the Filing:

Investor Owned Utilities (IOUs):
- Avista Utilities (Avista)
- Idaho Power Company (IPC)
- NorthWestern Energy (NorthWestern or NWE)
- PacifiCorp (PAC)
- Portland General Electric (PGE)
- Puget Sound Energy (PSE)

Consumer Owned Utilities (COUs):
- Franklin County PUD (Franklin)
- Snohomish County PUD (Snohomish)

Other Participants to the Filing:
- Idaho Public Utility Commission
- Public Power Council
- Public Utility Commission of Oregon (OPUC)
- Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine PacifiCorp's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This Draft Report describes the process, evaluation, and initial results of BPA's ASC review. After reviewing parties' comments on this Draft Report, BPA will publish a Final Report in July, 2009.

NOTE: If the filing utility or an intervenor wishes to preserve any issue regarding BPA's ASC Reports for subsequent administrative or judicial appeal, they must raise such issue in their comments on BPA's Draft ASC Reports. If a party fails to do so, the issue will be waived for subsequent appeal.

2. AVERAGE SYSTEM COST SUMMARY

2.1. Base Period ASC

The 2008 ASCM requires utilities participating in the ASC Review Process to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs, and Annual Reports, including Cost of Service Analysis (COSA) for COUs. The submitted information includes the Appendix 1, an Excel based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes CY 2007 Base Period ASC based on (1) the ASC information filed by PacifiCorp on October 15, 2008 (including errata, if applicable), and (2) the same information from the ASC Draft Report as adjusted by BPA after the ASC Review Process. This table does not reflect Exchange Period ASC, which is noted in subsequent tables.

Table 2.1: CY 2007 Base Period ASC
(Results of Appendix 1 calculations)

	October 15, 2008 As Filed	April 13, 2009 Draft Report
Production Cost	946,472,681	946,500,846
Transmission Cost	177,422,214	174,532,323
(Less) NLSL Costs	-	-
Contract System Cost	**1,123,894,895**	**1,121,033,170**
Total Retail Load (MWh)	21,476,886	21,476,886
(Less) NLSL	0	0
Total Retail Load (Net of NLSL)	21,476,886	21,476,886
Distribution Losses	575,581	575,581
Contract System Load	**22,052,467**	**22,052,467**
CY 2007 Base Period ASC ($/MWh)	**50.96**	**50.83**

2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December, 2007) to the end of the Exchange Period (September, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows 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.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information from the ASC Draft Report as adjusted by BPA after the ASC Review Process.

Table 2.2.1:
New Resource Additions Coming On-Line
Prior to Exchange Period New Resource Additions ($/MWh)

As-Filed FY 2010-2011 Exchange Period ASC				
Resource	**Group 1**	**Chehalis (525 MW)**	Group 3	**Group 4**
Expected On-Line Date	08/01/08	10/01/08	04/01/09	04/01/09
Delta*	**0.46**	**-3.10**	0.67	0.38

Draft Report FY 2010-2011 Exchange Period ASC				
Resource	**Group 1**	**Chehalis (525 MW)**	Group 3	**Group 4**
Expected On-Line Date	08/01/08	10/01/08	04/01/09	04/01/09
Delta*	**1.47**	**0.12**	1.16	0.58

*The Delta is the incremental change in the ASC as the new resources come on line.

Table 2.2.2:
New Resource Additions Coming On-Line
During the Exchange Period ($/MWh)

As-Filed FY 2010-2011 Exchange Period ASC				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On-Line Date				
Delta*				

Draft Report FY 2010-2011 Exchange Period ASC				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On-Line Date				
Delta*				

*The Delta is the incremental change in the ASC as the new resources come on line.

2.3. FY 2010-2011 Exchange Period ASC for the Draft Report

The following table identifies the Exchange Period ASC as filed on October 15, 2008, and as-adjusted by BPA for this Draft Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come on-line, and as identified above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

Table 2.3.1: Exchange Period FY 2010-2011 ASC ($/MWh)
Prior to the New Resource Additions

Date	October 15, 2008 As-Filed	April 13, 2009 Draft Report
FY 2010 - 2011	52.99	53.16

The as-filed Appendix 1 Filing, including the ASC Forecast Model and supporting documentation, PacifiCorp's ASC can be viewed at BPA's Residential Exchange Program (REP) website: **http://www.bpa.gov/corporate/finance/ascm/filings.cfm**.

3. FILING REQUIREMENTS

3.1. Introduction

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839c(c), established the REP. Any Pacific Northwest utility interested in participating in the REP may offer to sell power to BPA at the average system cost ASC of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. *See generally* H.R. Rep. No. 976, Pt. I, 96th Cong., 2d Sess. 60 (1980). The cost benefits established by the REP are passed through directly to the exchanging utilities' residential and small farm consumers. 16 U.S.C. § 839c(c)(3).

The Northwest Power Act gives BPA's Administrator the discretionary authority to determine ASC on the basis of a methodology established in a public consultation proceeding. 16 U.S.C. § 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. §§ 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. *See* 48 Fed. Reg. 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 Fed. Reg. 39,293 (Oct. 5, 1984). In the late 1980s and mid-1990s, BPA and exchanging utilities executed a number of termination agreements that provided for payments to each utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings. Subsequent REP Settlement Agreements with BPA's investor-owned utility customers were in effect from approximately 2001 through 2007, but were terminated following a judicial decision issued on May 3, 2007.

In 2007, BPA began administrative efforts to resume the full implementation of the REP, including the development of new RPSAs and a consultation proceeding to revise the 1984 ASC Methodology. As with the 1981 and 1984 ASC Methodologies, the 2008 ASCM was developed in a consultation proceeding with interested parties through, in part, a series of working group meetings conducted by BPA staff. The goal of the consultation process was to develop an administratively feasible ASC Methodology that would be technically sound and comport with the Northwest Power Act. The ASCM is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission). On September 30, 2008, the Commission granted interim approval to BPA's 2008 ASCM.

BPA maintains a significant role in reviewing utilities' ASC filings to ensure compliance with the 2008 ASCM. For more information regarding the 2008 ASCM, please refer to the *Final Record of Decision, 2008 Average System Cost Methodology*, June 30, 2008.

3.2. <u>ASC Review Process - FY 2010-2011</u>

Under the 2008 ASCM, utilities' ASCs are generally established prior to the calculation and payment of REP benefits, and the ASC Review Process occurs before the beginning of the Exchange Period.

On October 15, 2008, exchanging utilities submitted ASC filings for the FY 2010-2011 Exchange Period. All data were submitted using two Excel-based models: the Appendix 1 and the ASC Forecast Model. Supporting documentation was also submitted. A utility's submission of the models and supporting documentation is defined as the utility's "ASC filing."

To determine a utility's Exchange Period ASC for FY 2010-2011 (October 1, 2009, through September 30, 2011), the Base Period (CY 2007) ASC is first calculated using the Appendix 1.

BPA then uses the ASC Forecast Model to escalate the Base Period ASC forward to the effective Exchange Period. The Base Period and Forecast ASC results are reported herein.

The 2008 ASCM allows utilities to file multiple, contingent ASCs to reflect changes to service territories, and allows for changes to ASCs resulting from major resource additions and reductions.

The exchanging utilities' October 15, 2008, ASC filings began the formal review and comment processes, referred to as the Review Period, to establish the utilities' respective ASCs. For the Draft Reports, BPA completed a preliminary review of the utilities' ASC filings in conformance with the 2008 ASCM, which was approved by FERC on an interim basis on September 30, 2008. Parties had a full and complete opportunity to intervene in BPA's ASC Review Processes and to submit comments on the utilities' ASC filings. The Review Processes for FY 2010-2011 ASCs are still in progress at this publication date. Upon completion of the formal reviews and final ASC determinations, BPA will publish Final Reports in July, 2009 for each participating utility.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision*, *2008 Average System Cost Methodology*, *June 2008*, entitled *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 and Conservation Act.*

3.3. Explanation of Schedules

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information that present the data necessary to calculate ASCs. The schedules and support data are as follows:

1. Schedule 1 - Plant Investment/Rate Base
2. Schedule 1A - Cash Working Capital Calculation
3. Schedule 2 - Capital Structure and Rate of Return
4. Schedule 3 - Expenses
5. Schedule 3A - Taxes
6. Schedule 3B - Other Included Items
7. Schedule 4 - Average System Cost
8. Distribution of Salaries and Wages
9. Purchased Power and Off-System Sales
10. New Large Single Loads
11. Labor Ratios

3.3.1. Schedule 1 – Plant Investment/Rate Base

This schedule establishes the rate base used by the utility. The calculation begins with a determination of the Gross Electric Plant In-Service, which includes the historical costs of the Intangible, General, Production, Transmission, and Distribution Plant. For exchanging utilities that provide electric and natural gas service, the portion of common plant allocated to electric service is also included. These values (and all subsequent values) are entered into the Appendix 1 filing as line items based on the FERC Uniform System of Accounts. In general, each line item (Account) is functionalized to Production, Transmission, and/or Distribution/Other in accordance with the functionalizations prescribed in the 2008 ASCM, Attachment A, Table 1.

Next, in order to reflect the book value of the remaining plant, depreciation and amortization reserves are evaluated and entered into the Appendix 1 form and functionalized. These are then subtracted from the Gross Electric Plant In-Service to determine the Net Electric Plant.

The resulting Total Net Electric Plant is adjusted, where appropriate, to reflect additions in Cash Working Capital (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, and Deferred Debits. It is adjusted again, where appropriate, to deduct the Current and Accrued Liabilities, and Deferred Credits. The outcome of these adjustments defines the Total Rate Base. When the Total Production and Total Transmission (calculated in the Total Rate Base) are multiplied by the Rate of Return as determined in Schedule 2, the result is the utility's return on investment.

3.3.2. Schedule 1A – Cash Working Capital

Cash working capital is a ratemaking convention that is not included in the FERC Uniform System of Accounts, but is a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a utility, BPA allows one-eighth of the functionalized costs of total production expenses, transmission expenses and administrative and general expenses, less purchased power, fuel costs, and public purpose charges.

3.3.3. Schedule 2 – Capital Structure and Rate of Return

This schedule lists the data used by the utility to develop the rate of return applied to the utility's rate base developed on Schedule 1 to determine the utility's return on investment.

Investor-owned utilities (IOU) use the weighted cost of capital (WCC) from their most recent State Commission Rate Order with a Federal income tax adjustment to determine the return calculation. The return on equity (ROE) used in the WCC calculation is grossed up for Federal income taxes at the marginal Federal income tax rate using the formula found in the ASCM, Attachment A, Section IX, Endnote b. For consumer-owned utilities (COU), the rate of return is equal to the COU’s weighted cost of debt times total rate base as determined in Schedule 1.

3.3.4. Schedule 3 – Expenses

This schedule represents operations and maintenance expense for the production, transmission and distribution of electricity. Each expense item is functionalized as outlined in the 2008 ASCM, Table 1. Additional expenses associated with customer accounts, sales, administrative and general expense, conservation program expense, and depreciation and amortization expense associated with Electric Plant in Service are also included. The sum of these costs is Total Operating Expenses.

3.3.5. Schedule 3A – Taxes

This schedule presents allowable ASC costs for Federal employment tax and non-Federal taxes, including property and unemployment taxes. State income taxes, franchise fees, regulatory fees, and city/county taxes are included but are functionalized to Distribution/Other and therefore not incorporated in ASC. Taxes and fees for each state listed are grouped together and entered as "combined" line items for Appendix 1 filing purposes.

Federal income taxes included in ASC are calculated and described in Schedule 2 above, *Capital Structure and Rate of Return*.

3.3.6. Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity to others (wheeling). Items in this schedule are deducted from the total costs of each utility.

3.3.7. Schedule 4 – Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Federal income tax adjusted return on rate base, total operating expenses, state and other taxes, and other included items. The schedule also identifies the Contract System Cost and Contract System Load, as defined below, and calculates the utility's ASC ($/MWh).

<u>Contract System Cost</u>:
Contract System Cost (CSC) includes the utility's costs for production and transmission resources, including power purchases and conservation measures, which are includable in and subject to the provisions of the Appendix 1. Costs to serve NLSLs are excluded from ASC calculations. CSC becomes the numerator in calculating ASC.

<u>Contract System Load (MWh)</u>:
The Contract System Load (CSL) is the total regional retail load, adjusted for distribution losses and NLSLs, pursuant the 2008 ASCM. The CSL is the denominator in calculating ASC.

3.3.8. Distribution of Salaries and Wages

This supporting file is used to determine the Labor Ratio calculations and includes salaries and wages from relevant operations and maintenance of the electric plant.

3.3.9. Purchased Power and Sales for Resale

Purchased Power is an Account of Schedule 3, *Expenses*, and includes all power purchases the utility made during the year, including power exchanges. Sales for Resale is an Account of Schedule 3B, *Other Included Items*, and includes power sales to purchasers other than ultimate consumers. Listed in the information for both Accounts is the statistical classification code for all transactions. Refer to the FERC Form 1, pages 310-311 for Sales for Resale, and pages 326-327 for Purchased Power, for identification of the classification codes.

3.3.10. New Large Single Loads

An NLSL is any load associated with a new facility, an existing facility or an expansion of an existing facility, which was not contracted for or committed to (CF/CT) prior to September 1, 1979, and which will result in an increase in power requirements of the specific customer of ten average megawatts (10 aMW) or more in any consecutive twelve-month period.

BPA determines the cost of serving NLSLs by using the fully allocated cost of all post-September 1, 1979, resources and long-term power purchases greater than five years in duration.

NLSLs and the associated costs to serve them are not included in utilities' ASCs.

3.3.11. Labor Ratios

These ratios 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 FERC Form 1. For COUs, comparable data is used based on the cost of service analysis (COSA) study used as the basis for retail rates in effect during the Base Period filing.

3.4. <u>ASC Forecast</u>

Once BPA determines the Base Period ASC, it applies this data in an Excel-based forecasting model (ASC Forecast Model) to escalate the Base Period ASC data forward to the Exchange Period, which in this case is FY 2010-2011. BPA used 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. For the Draft Reports, the escalators were updated to be consistent with the escalators used in the WP-10 Power Rate Case. For additional background on the determination of Exchange Period ASCs, see the 2008 ASCM, Section IV, *Rules for Determining Exchange Period Average System Cost*, Subsection A.

3.4.1. Forecast Contract System Cost

Forecast Contract System Cost (CSC) includes a utility's forecast 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. As outlined in the 2008 ASCM, Section IV, *Rules for Determining Exchange Period Average System Cost*, Subsection A, "Forecast CSC," BPA escalates base period costs to the midpoint of the FY 2010-2011 Exchange Period (October 1, 2010) to calculate Exchange Period ASCs. BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

3.4.2. Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. Utilities are then 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. For details, see the 2008 ASC Methodology, Section IV, *Rules for Determining Exchange Period Average System Cost*, Subsection B.

3.4.3. Forecast Contract System Load and Exchange Load

All utilities are required to provide, with their Appendix 1 filings, a four-year forecast of their total retail load, as measured at the meter, and their qualifying residential and small farm retail load, as measured at the retail meter. Also required is a current distribution loss study as described in the 2008 ASCM, Attachment A, Endnote e. The total retail and residential and small farm load forecasts are adjusted for distribution losses and NLSLs when appropriate. The resulting load forecasts are the Contract System Load forecast and Exchange Load forecast, respectively.

3.4.4. Major Resource Additions

BPA uses the method outlined in the 2008 ASCM, Section IV, *Rules for Determining Exchange Period Average System Cost*, Subsection C, to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold of 2.5 percent. These additions include new production or 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.

The exchanging utility provides its forecast of major resource additions and all associated costs. The forecast covers the period from the end of the Base Period to the end of the Exchange Period.

The forecast of the major resource costs to be included in the utility’s Exchange Period ASC is reviewed and determined during the Review Period. When calculating the utility’s Exchange Period ASC, all resources included prior to the start of the Exchange Period are projected forward to the midpoint of the Exchange Period. All resources included during the Exchange Period will be included at the midpoint of the Exchange Period.

3.4.5. Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecasted utility-specific short-term purchased power price. BPA uses the method outlined in the 2008 ASCM, Section IV, *Rules for Determining Exchange*, Subsection D.

4. REVIEW OF THE ASC FILING

Pursuant to the 2008 ASCM and section 5(c) of the Northwest Power Act, BPA is responsible for reviewing all costs and loads used to establish ASCs. During this review and evaluation, numerous issues may be identified for comment by BPA or other parties. BPA's ASC determination is limited to specific findings on those issues identified for comment, with the exception of ministerial or mathematical errors. There may have been additional issues that BPA did not identify for comment in this filing. Acceptance of a utility's treatment of an item without comment is not intended to signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASCM. Similarly, given that the current report is one of the first published under the 2008 ASCM, further experience under the 2008 ASCM may result in amendment or refinement of determinations made herein when addressed in future ASC reviews.

4.1. Identification and Analysis of Issues from BPA Issue List

BPA raised the following issues during the ASC Review Process, and PacifiCorp submitted its responses. No other party raised or commented on PacifiCorp's responses. Each issue pertains to the October 15, 2008, filing unless otherwise noted.

Although a utility's State regulatory bodies or FERC may allow a particular functionalization to a specific account, this does not require that BPA will follow the same functionalization for the same account in calculating a utility's ASC. BPA retains the discretion to make an independent determination of the appropriateness of inclusion or exclusion of particular costs, as well as the functionalization method used in the calculation of that cost, in conformance with the 2008 ASCM.

4.2. SCHEDULE 1: Plant Investment/Rate Base:

4.2.1. Account 303, Intangible Plant Miscellaneous: *KWH Historical Data Collection*

Statement of Issue:

What is the correct functionalization of the Account 303 – 3031570: KWH Historical Data Collection?

Statement of Facts:

In response to ASC-09-PA/PacifiCorp Data Request 33, PAC stated that Asset 3031570 supports the Transmission and Generation functions of the Company and should be allocated to PT. PAC claims PT is not an "allowable" functionalization, and therefore functionalized it to PTD.

Direct analysis does not preclude the direct functionalization of an account by any means as long there is a clear description and justification for the functionalization.

Summary of Parties' Positions:

PAC proposes that a specific subaccount of Account 303 should be functionalized "PT" and proposes that the ratio should be plant-based.

Analysis of Positions:

Direct analysis does not preclude the direct functionalization of an account by any means as long there is a clear description and justification for the functionalization.

Asset 3031570 supports the Transmission and Generation functions of the Company and should be allocated to PT.

BPA supports the change of the subaccount to the PT ratio based on plant.

Draft Decision:

Account 303 – 3031570: KWH Historical Data Collection will be functionalized by the PT ratio based on plant.

Table 4.2.1: Account 303, Intangible Plant Miscellaneous:
KWH Historical Data Collection
($000s)

Account Description		Total	Prod	Tran	Dist
AS FILED					
KWH Historical Data Collection	PTD	348	159	67	122
ADJUSTED					
KWH Historical Data Collection	PT	348	244	103	-

4.2.2. Account 303, Intangible Plant Miscellaneous: *Customer Service System (CSS)*

Statement of Issue:

What is the correct functionalization of Account 303 – 3031830: Customer Service System (CSS)?

Does the direct analysis justify the functionalization of the account to PTD?

Should this asset be functionalized to Distribution to conform to the O&M Accounts?

Statement of Facts:

In response to ASC-09-PA/PacifiCorp Data Request 33, PAC stated that the Customer Service System is the software that contains information on all of the Company's customers. PAC contends that the system bills customers for Generation, Transmission and Distribution services and is thus appropriately functionalized PTD.

PAC argues that "although the business is used to bill retail customers, it would be inappropriate to functionalize these costs solely to Distribution. In determining the proper functionalization, the focus should be on what costs the Company is recovering using this computer software. The Company states that it is recovering all costs, including wholesale costs, using this software and therefore the assignment of the software to PTD is appropriate."

Summary of Parties' Positions:

PAC argues that it recovers all costs, including wholesale costs, using Customer Service Systems and therefore the assignment of the software to PTD is appropriate."

PAC argues that "although the business is used to bill retail customers, it would be inappropriate to functionalize these costs solely to Distribution. In determining the proper functionalization, the focus should be on what costs the Company is recovering using this computer software. The Company states that it is recovering all costs, including wholesale costs, using this software and therefore the assignment of the software to PTD is appropriate."

Analysis of Positions:

Section VIII.B, Table 1 of the 2008 ASCM, provides that functionalization of Account 303 is direct analysis with an option to Distribution.

The 2008 ASCM states "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." *Id* at 16.

When utilities perform a direct analysis on an Account, they must submit sufficient documentation so that BPA can determine if the functionalization is reasonable. In addition, the 2008 ASCM states that "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." *Id.* at 17.

Customer Information Systems (CIS) manage retail customer information, bill calculation and presentation, and payment processes.

In the description of the software provided in the response to BPA Data Request No. 006, the software appears to be primarily used in the retail part of the business. PSE's justification provided in the data response for using the PTD ratio for this account was that CIS "supports all functions of the company." Such catchall phrases, if taken to the extreme, could be used to rationalize using the PTD ratio to functionalize the entire ASC filing using the PTD ratio. Such simple statements do not constitute a valid direct analysis.

The functionalization of a software system should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM.

The description of the software indicates the software is primarily used for the retail side of the business and used in the billing process. Even though the software is used to bill the expenses incurred by the Generation, Transmission and Distribution services, the expense and sophistication of the software is driven by the size and diversification of the retail (distribution) side of the business. In addition, the software replaces tasks that were previously performed manually and were charged to the Customer Accounts Expenses, Accounts 901-905. The 2008 ASCM functionalizes Accounts 901-905 to Distribution. BPA believes that the functionalization of software that performs or replaces work or manual processes should generally follow the functionalization as the account where the work was performed. For example, automated generation control software that automatically adjusts load and other controllable variables of a generation plant that were previously performed by plant operators would be functionalized to Production. BPA will functionalize software in Account 303 based on the functionalization of the Account where the expenses for the work process performed by the software are charged, which for CIS software is Accounts 901-910.

<u>Draft Decision:</u>

Account 303 – 3031830: Customer Service System (CSS) will be functionalized to Distribution.

Table 4.2.2: Account 303, Intangible Plant Miscellaneous:
Customer Service System (CSS
($000s)

Account Description		**Total**	**Prod**	**Tran**	**Dist**
AS FILED					
Customer Service System (CSS)	PTD	105,494	48,244	20,367	36,883
ADJUSTED					
Customer Service System (CSS)	DIST	105,494	-	-	105,494

4.2.3. Account 303, Intangible Plant Miscellaneous: *Franchise Tax System*

Statement of Issue:

What is the correct functionalization of the Account 303 – 3032030: Franchise Tax System?

Statement of Facts:

In response to ASC-09-PA/PacifiCorp Data Request 33, PAC stated that Asset 3032030 takes revenue and volumetric data from the CSS and SAP systems to compute and report taxes. PAC states that since both the CSS and SAP systems are functionalized with PTD, this asset should also be functionalized with PTD.

PAC states in its response to Issue #3 that "BPA believes that since franchise taxes are not exchangeable and functionalized to Distribution, it seems that the software used to track the franchise taxes should not be exchangeable. The franchise tax system should, therefore, be functionalized to Distribution."

The 2008 ASCM precludes the exchange of franchise taxes and therefore they should be functionalized to Distribution.

Summary of Parties' Positions:

PAC believes that since franchise taxes are not exchangeable and functionalized to Distribution, it seems that the software used to track the franchise taxes should not be exchangeable. The franchise tax system should, therefore, be functionalized to Distribution."

Analysis of Positions:

The functionalization of a software system should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM. Additionally, the 2008 ASCM precludes the exchange of franchise taxes and therefore the account should be functionalized to Distribution.

Draft Decision:

Account 303, Intangible Plant Miscellaneous: Franchise Tax System will be functionalized to Distribution.

Table 4.2.3: Account 303, Intangible Plant Miscellaneous:
Franchise Tax System)
($000s)

Account Description		Total	Prod	Tran	Dist
AS-FILED					
Franchise Tax System	PTD	417	191	81	146
ADJUSTED					
Franchise Tax System	DIST	417	-	-	417

4.2.4. Account 303, Intangible Plant Miscellaneous: *Employee Performance & Salary System*

Statement of Issue:

*What is the correct functionalization of Account 303 – 3032290 Employee Performance & Salary System and should the functionalizatio*n *of a software system follow the functionalizations of the operations it supports?*

Statement of Facts:

In response to ASC-09-PA/PacifiCorp Data Request 33, PAC stated that Asset 3032290 is the software which allows employees to enter their annual goals and development plans. PAC's original filing functionalized this account using PTD. PAC now supports functionalization using the Labor ratio.

Summary of Parties' Positions:

PAC supports functionalization using the Labor ratio.

Analysis of Positions:

The functionalization of a software system should follow the functionalization of the operation it supports and the Employee Performance & Salary System supports the achievement of employee/labors annual goals and development plans.

PAC supports the functionalized using the Labor ratio rather than the PTD ratio used in the Company's original filing.

Draft Decision:

Account 303, Intangible Plant Miscellaneous: Employee Performance & Salary System will be functionalized to Labor.

Table 4.2.4: Account 303, Intangible Plant Miscellaneous:
Employee Performance & Salary System
($000s)

Account Description		Total	Prod	Tran	Dist
AS FILED					
Employee Performance and Salary System	PTD	657	301	127	230
ADJUSTED					
Employee performance & salary system	LABOR	657	292	48	317

4.2.5. Account 303, Intangible Plant Miscellaneous: *Electronic Tagging Outage Manage System*

Statement of Issue:

What is the correct functionalization of Account 303 – 3032320 Electronic Tagging Outage Manage System?

Statement of Facts:

In response to ASC-09-PA/PacifiCorp Data Request 33, PAC stated this asset develops NERC-mandated information for the tracking of its energy transactions between power marketing and transmission companies. It supports the Transmission and Generation functions of the Company and should be allocated PT. As this is not an "allowable" functionalization, the Company functionalized it to PTD.

Summary of Parties' Positions:

PAC proposes that this specific subaccount of Account 303 should be functionalized to PT and proposes that the ratio should be plant-based.

Analysis of Positions:

Direct analysis does not preclude the direct functionalization of an account by any means as long there is a clear description and justification for the functionalization.

The above-noted asset develops NERC-mandated information for the tracking of PAC's energy transactions between power marketing and transmission companies. It supports the Transmission and Generation functions of the Company.

PAC proposes that the specific subaccount of Account 303 should be functionalized to PT and proposes that the ratio should be plant-based.

Draft Decision:

Account 303 – 3032320 Electronic Tagging Outage Manage System should be functionalized by the PT ratio based on plant.

Table 4.2.5: Account 303, Intangible Plant Miscellaneous:
Electronic Tagging Outage Manage System
($000s)

Account Description		Total	Prod	Tran	Dist
AS FILED					
Electronic Tagging Outage Manage System	PTD	1,352	618	261	473
ADJUSTED					
Electronic Tagging Outage Manage System	PT	1,352	951	401	-

4.2.6. Account 303, Intangible Plant Miscellaneous: *HR- Benefits Open Enrollment Online*

Statement of Issue:

What is the correct functionalization of Account 303 – 3032380 HR Benefits Open Enrollment Online?

Statement of Facts:

Asset 3032380 is the software system that allows employees to select among medical, dental and vision plans. PAC's original filing functionalized this account using PTD. In response to Data Request 33, PAC now supports functionalization using the Labor ratio.

Summary of Parties' Positions:

PAC supports functionalization using the Labor ratio.

Analysis of Positions:

The functionalization of a software system should follow the functionalization of the operation it supports. A software system that allows employees select among medical, dental and vision plans supports the employee/laborers' selection of their medical plans.

The costs of medical, dental and vision plans are functionalized to Labor. Software that supports such plans should be functionalized in the same manner.

Draft Decision:

Account 303 – 3032380 HR- Benefits Open Enrollment Online will be functionalized to Labor.

Table 4.2.6: Account 303, Intangible Plant Miscellaneous:
HR- Benefits Open Enrollment Online
($000s)

Account Description		Total	Prod	Tran	Dist
AS FILED					
HR- Benefits Open Enrollment Online	PTD	343	157	66	120
ADJUSTED					
HR- Benefits Open Enrollment Online	LABOR	343	152	25	165

4.2.7. Account 303, Intangible Plant Miscellaneous: *Fieldnet Pro Meter Reading Syst -HRP REP*

Statement of Issue:

What is the correct functionalization of the Fieldnet Pro Meter Reading Syst -Hrp Rep?

Statement of Facts:

PAC's original filing functionalized this account using PTD. This software system is used to manage the meter reading for retail customers. In response to ASC-09-PA/PacifiCorp Data Request 33, PAC now supports functionalization using the Distribution ratio.

Summary of Parties' Positions:

PAC supports functionalization using the Distribution ratio.

Analysis of Positions:

The cited software system is used to manage meter reading for retail customers.

PAC proposes that the specific sub account of Account 303 should be functionalized "Dist".

Draft Decision:

Account 303, Intangible Plant Miscellaneous: Fieldnet Pro Meter Reading Syst -HRP REP will be functionalized to Distribution.

Table 4.2.7: Account 303, Intangible Plant Miscellaneous:
Fieldnet Pro Meter Reading Syst-HRP REP
($000s)

Account Description		Total	Prod	Tran	Dist
AS FILED					
FIELDNET PRO Meter Reading Syst -HRP REP	PTD	2,908	1,330	561	1,017
ADJUSTED					
FIELDNET PRO Meter Reading Syst -HRP REP	DIST	2,908	-	-	2,908

4.2.8. Account 303, Intangible Plant Miscellaneous: *Mid Office Improvement Project*

Statement of Issue:

What is the correct functionalization of Account 303 – 3032450 Mid Office Improvement Project?

Statement of Facts:

In response to ASC-09-PA/PacifiCorp Data Request 33, PAC stated that Asset 3032450 is software programs that support the Company's Mid-Office group, part of the Commercial and Trading organization, and thus the software is functionalized to Production.

PAC states in its response to Issue 8 that "the *Mid Office Improvement Project* software programs are programs that support and improve the Company's Mid-Office group, which is a part of the Commercial and Trading organization. All costs associated with this organization are booked to FERC Account 557, which is functionalized to PROD. PAC agrees with the proposal raised by BPA in the Discussion sections of Issues 2, 3 and 4 that the functionalization of a software system should follow the functionalization of the operation it supports. Thus, consistent with this approach, this account should be functionalized to PROD."

Summary of Parties' Positions:

PAC contends that *Mid Office Improvement Project* software programs are programs that support and improve the Company's Mid-Office group, which is a part of the Commercial and Trading organization. All costs associated with this organization are booked to FERC Account 557, which is functionalized to Production.

Analysis of Positions:

The cited software programs are programs that support and improve the Company's Mid-Office group, which is a part of the Commercial and Trading organization. All costs associated with this organization are booked to FERC Account 557, which is functionalized to Production. The functionalization of a software system should follow the functionalization of the operation it supports. Thus, consistent with this approach, the Mid Office Improvement Project should be functionalized to Production.

Draft Decision:

Account 303 – 3032450 Mid Office Improvement Project will be functionalized to Production.

There is no change in the ASC.

4.2.9. Account 303, Intangible Plant Miscellaneous: *Outage Call Handling Integration*

Statement of Issue:

What is the correct functionalization of the Account 303 – 3032480 - Outage Call Handling Integration?

Statement of Facts:

The Outage Call Handling Integration is a software system where the primary purpose is to assist in the management and response to outages of retail customers.

In response to ASC-09-PA/PacifiCorp Data Request 33, PAC now believes that Asset 3032480 should more appropriately be functionalized to Distribution rather than PTD.

Summary of Parties' Positions:

PAC now believes that Asset 3032480 should more appropriately be functionalized to Distribution rather than PTD.

Analysis of Positions:

Section VIII.B, Table 1 of the 2008 ASCM, provides that functionalization of Account 303 is direct analysis with an option to Distribution.

The 2008 ASCM states "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." *Id* at 16.

When utilities perform a direct analysis on an Account, they must submit sufficient documentation so that BPA can determine if the functionalization is reasonable. In addition, the 2008 ASCM states that "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." *Id.* at 17.

BPA believes that the functionalization of a software system should generally follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM. Both BPA and PAC agree that the software supports the retail side of the business.

Draft Decision:

Account 303 – 3032480 - Outage Call Handling Integration will be functionalized to Distribution.

Table 4.2.9: Account 303, Intangible Plant Miscellaneous:
Outage Call Handling Integration
($000s)

Account Description		Total	Prod	Tran	Dist
AS FILED					
Outage Call Handling Integration	PTD	1,981	906	382	693
ADJUSTED					
Outage Call Handling Integration	DIST	1,981	-	-	1,981

4.2.10. Account 303, Intangible Plant Miscellaneous: *On Line Employee Expense Express*

Statement of Issue:

What is the correct functionalization of the Account 303 – 3032500 - On Line Employee Expense Express?

Statement of Facts:

Outage Call Handling Integration is a software system where the primary purpose is to assist employees/labor in the management of their expenses.

PACs original filing functionalized this account using PTD. In response to ASC-09-PA/PacifiCorp Data Request 33, PAC now supports functionalization by the Labor ratio.

Summary of Parties' Positions:

PAC supports functionalization by the Labor ratio.

Analysis of Positions:

The functionalization of a software system should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM. Both BPA and PAC agree that the software supports the employees/labor in conducting their work and that the Labor ratio best reflects its functional nature.

Draft Decision:

Account 303 – 3032500 - On Line Employee Expense Express will be functionalized to Labor.

Table 4.2.10: Account 303, Intangible Plant Miscellaneous:
On Line Employee Expense Express
($000s)

Account Description		Total	Prod	Tran	Dist
AS FILED					
On Line Employee Expense Express	PTD	765	350	148	267
ADJUSTED					
On Line Employee Expense Express	LABOR	765	339	56	369

4.2.11. Account 303, Intangible Plant Miscellaneous: *Computer Based Training (CBT)*

Statement of Issue:

What is the correct functionalization of Account 303 – 3032810 - Computer Based Training (CBT)?

Statement of Facts:

In response to ASC-09-PA/PacifiCorp Data Request 33, PAC stated that Asset 3032810 is a computer-based training system at the Company's production plants. The Company now supports a functionalization of Production rather than PTD as more appropriate for this asset.

Summary of Parties' Positions:

PAC supports a functionalization of this asset to Production rather than PTD.

Analysis of Positions:

The functionalization of a software system should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM. Both BPA and PAC agree that the software supports a training system at the Company's production plants and that the Production ratio best reflects its functional nature.

PAC supports a functionalization of this asset to Production.

Draft Decision:

Account 303 – 3032810 - Computer Based Training (CBT) will be functionalized to Production.

Table 4.2.11: Account 303, Intangible Plant Miscellaneous:
Computer Based Training (CBT)
($000s)

Account Description		Total	Prod	Tran	Dist
AS FILED					
Computer Based Training (CBT)	PTD	1,128	516	218	395
ADJUSTED					
Computer Based Training (CBT)	PROD	1,128	1,128	-	-

4.2.12. Account 303, Intangible Plant Miscellaneous: *RCDA Regulation Discovery Tool*

Statement of Issue:

What is the correct functionalization of the Account 303 – 3033020 - RCDA Regulation Discovery Tool?

Statement of Facts:

In response to ASC-09-PA/PacifiCorp Data Request 33, PAC stated that Asset 3033020 is the Regulation Discovery software that supports the discovery process in all Federal and State regulatory proceedings. PAC claimed that it is appropriately functionalized using PTD because regulation embraces all assets of the Company.

PAC states in its response to Issue 16 that "BPA's statement "Under the 2008 ASCM, Regulatory costs not exchangeable" is incorrect. One specific expense – Regulatory Commission Expenses (Account 928) – is not exchangeable, but expenses associated with discovery are booked to Account 920, not to Account 928. Account 920 is functionalized to labor, and therefore the software supporting the expenses in this account should be similarly functionalized to labor."

Summary of Parties' Positions:

PAC supports a functionalization of the account to Labor.

Analysis of Positions:

The functionalization of a software system should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM.

Section 4.3.13 of the 2008 ASCM makes clear that regulatory commission expenses are not exchangeable. The software used to support the discovery process in all Federal and State regulatory proceedings should therefore not be exchangeable. BPA agrees, however, that the software costs should follow the labor oversight costs and therefore BPA functionalizes the software should be allocated to Labor.

Draft Decision:

Account 303 – 3033020 - Rcda Regulation Discovery Tool will be functionalized to Labor.

Table 4.2.12: Account 303, Intangible Plant Miscellaneous:
Rcda Regulation Discovery Tool
($000s)

Account Description		Total	Prod	Tran	Dist
AS FILED					
RCDA Regulation Discovery Tool	PTD	667	305	129	233
ADJUSTED					
RCDA Regulation Discovery Tool	LABOR	667	305	129	233

4.2.13. Account 303, Intangible Plant Miscellaneous: *CTHAS-C&T Hedge Actg/Actg Standards*

Statement of Issue:

What is the correct functionalization of Account 303 – 3033110 - CTHAS-C&T Hedge Actg/Actg Standards?

Statement of Facts:

In response to ASC-09-PA/PacifiCorp Data Request 33, PAC stated that Asset 3033110 is the software interface between the Commercial and Trading Hedging Accounting System and the Commercial and Trading Accounting Standards Data Base and is thus functionalized to Production.

PAC states in its response to Issue 17 that the cost of software used to support hedging activity should therefore be functionalized to Distribution.

Summary of Parties' Positions:

PAC states that the cost of software used to support hedging activity should be functionalized to Distribution.

Analysis of Positions:

The functionalization of a software system should follow the functionalization of the operation it supports. Under Section 4.3.3 of the 2008 ASCM, derivatives are not exchangeable and are therefore functionalized to Distribution. This system should therefore be functionalized to Distribution.

Draft Decision:

Account 303 – 3033110 - CTHAS-C&T Hedge Actg/Actg Standards will be functionalized to Distribution.

Table 4.2.13: Account 303, Intangible Plant Miscellaneous:
CTHAS-C&T Hedge Actg/Actg Standards
($000s)

Account Description		Total	Prod	Tran	Dist
AS FILED					
CTHAS-C&T Hedge Actg/Actg Standards Inte	PROD	273	273	-	-
ADJUSTED					
CTHAS-C&T Hedge Actg/Actg Standards Inte	DIST	273	-	-	273

4.2.14. Account 303, Intangible Plant Miscellaneous: *Miscellaneous Software*

Statement of Issue:

What is the correct functionalization of Account 303 – Miscellaneous Software?

Statement of Facts:

Miscellaneous software is defined as that software that does not easily fit into other categories; such as Customer Information System (CIS), Billing, Metering, Employee Information, Facilities Management, etc. These are software systems that generally make employees more efficient at their jobs. For example, MICROSOFT OFFICE XP LICENSES is a license for Microsoft office suites that are used by employees' computers.

PACs explanation of the items was not sufficiently clear to allow an understanding of the software's purposes.

Summary of Parties' Positions:

PAC supports functionalization for most of the software that BPA has classified as miscellaneous using the PTD ratio.

Analysis of Positions:

The functionalization of a software system should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM.

When direct analysis is used, there is a requirement for a clear description and justification for the functionalization of all accounts and sub-accounts.

PACs explanation of the items was not sufficiently clear to allow an understanding of the software's purposes and therefore the applicability and justification of the functionalization to PTD.

The software PAC classified as miscellaneous appears to be either used by a large number of PAC employees or supports the general IT infrastructure and more accurately functionalized to the operation it supports or replaces, which are PSE's employees. Therefore, the Labor ratio more accurately reflects the appropriate functionalization.

For software that is in general and widespread use throughout the utility such as Microsoft Office, Microsoft Exchange Server, Anti-Virus applications Adobe products, or for software where the functional nature cannot be determined or the cost of the software is less than 1% of the total cost in Account 303 – Software. LABOR

The software BPA has classified as miscellaneous is more accurately functionalized to the operation it supports, which is PACs employees. Therefore, the Labor ratio more accurately reflects the appropriate functionalization.

Draft Decision:

Account 303 – Miscellaneous Software will be functionalized to Labor.

Table 4.2.14: Account 303, Intangible Plant Miscellaneous: Miscellaneous software ($000s)

Account Description		Total	PROD	TRAN	DIST
AS FILED					
WAN/LAN Sftwr for TCP/VAX Netwk	PTD	181	83	35	63
Endeavor Program Library	PTD	748	342	144	261
Outage Reporting System	PTD	3,498	1,600	675	1,223
Recruitsoft Applicant Tracking Sys Inter	PTD	237	109	46	83
Key Performance Indicator Dashboard	PTD	998	456	193	349
Financial Forecast Integration	PTD	394	180	76	138
Office Xp Software	PTD	1,441	659	278	504
Power Tax	PTD	792	362	153	277
Intranet Search Engine	PTD	498	228	96	174
Utility International Forecasting Model	PTD	1,662	760	321	581
2003 CCO OPEX Machine Software	PTD	538	246	104	188
Vcpro - Xerox Cust Stmt Frmtr Enhance -	PTD	2,179	996	421	762
Version Control System	PTD	326	149	63	114
WEB Software	PTD	4,279	1,957	826	1,496
VISIO PRO	PTD	417	190	80	146
Total		18,188	8,318	3,512	6,359
ADJUSTED					
WAN/LAN Sftwr for TCP/VAX Netwk	LABOR	181	80	13	87
Endeavor Program Library	LABOR	748	332	55	361
Outage Reporting System	LABOR	3,498	1,552	258	1,688
Recruitsoft Applicant Tracking Sys Inter	LABOR	237	105	17	115
Key Performance Indicator Dashboard	LABOR	998	443	73	482

Account Description		Total	PROD	TRAN	DIST
Financial Forecast Integration	LABOR	394	175	29	190
Office XP Software	LABOR	1,441	640	106	696
Power Tax	LABOR	792	352	58	382
Intranet Search Engine	LABOR	498	221	37	240
Utility International Forecasting Model	LABOR	1,662	738	122	802
2003 CCO OPEX Machine Software	LABOR	538	239	40	260
VCPRO - Xerox Cust Stmt Frmtr Enhance -	LABOR	2,179	967	160	1,051
Version Control System	LABOR	326	145	24	157
WEB Software	LABOR	4,279	1,899	315	2,065
VISIO PRO	LABOR	417	185	31	201
Total		18,188	8,071	1,339	8,778

4.2.15. Account 303, Intangible Plant Miscellaneous: *Enterprise Resource Planning Software*

Statement of Issue:

What is the correct functionalization of Account 303 – Enterprise Resource Planning Software?

Statement of Facts:

Enterprise Resource Planning (ERP) Systems provide a common foundation for business accounting, including common functions such as accounts payable, general ledger, and accounts receivable. Representative vendor solutions include: Lawson Enterprise Financial Management, Oracle B-Business Suite, PeopleSoft Enterprise Financial Management Solutions, and SAP ERP Financials.

PAC's explanation of the items was not sufficiently clear to allow an understanding of the software's purposes.

Summary of Parties' Positions:

PAC contends that the Enterprise Resource Planning (ERP) System should be functionalized to PTD.

Analysis of Positions:

Table 1 of the 2008 ASCM provides that the functionalization method for this account is direct analysis with a default to Distribution.

The 2008 ASCM states "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." *Id at 16.*

When utilities perform a direct analysis on an Account, they must submit sufficient documentation so that BPA can determine if the functionalization is reasonable. In addition, the 2008 ASCM states that "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." *Id. at 17*.

BPA's review of the initial ASC filings revealed that most utilities either used the PTD or Labor ratio to functionalize a majority of Account 303 software. However, the functionalization methodology and rationale for the direct analysis was not consistent among utilities. Some of the statements included by utilities to support functionalization of a specific piece of software using the PTD ratio used terms like "supports all functions of the company"[1] or "supports all areas of the company."[2] These catchall phrases, if taken to the extreme, could be used to rationalize using the PTD ratio to functionalize the entire ASC filing using the PTD ratio. Such simple statements do not constitute a valid direct analysis.

BPA and the parties generally support the concept that the functionalization of a software system should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM. While the concept is easy enough to understand, it is difficult to implement within the context of a utility's ASC filing because of how the software is recorded or listed in internal databases of software in the utility information systems and because of the sheer volume of the individual items of software.

For example, a utility may record its customer information system (CIS) as 'Customer Information System' or record it by the name of the vendor such as Oracle, Harris, SAP or Ventyx, or by the application name such as Xcellant, Peace, or ConsumerLinX. Repeating this disparate method of recording software in a utility database for a 1,000 or more unique software products that a typical utility may have and the task of functionalizing the software for an ASC filing is difficult and time consuming for a utility analyst that may not have familiarity with the software and how and where it is used within the utility. Given this difficulty, it is not surprising that most utilities and their regulatory commissions use a simple ratio, such as PTD or labor, to functionalize most or all of the software in Account 303. This approach works well for development of retail rates which incorporate most, if not all, production, transmission and distribution costs of the utility.

---

[1] See, for example, Data Responses ASC-09 PA-BPA-12 and ASC-09-PS-BPA-6

[2] See, for example, data response ASC-09-PS-BPA-12, and Excel file E302,303,E399,Common 2006 filed.xls, DATA for ASC tab, column W.

However, a utility’s ASC may include only allowable production and transmission costs determined in accordance with the 2008 ASCM. Using the PTD or Labor ratio for all software costs could result in an incorrect functionalization of costs. For example, the costs of certain software packages are very large relative to others in Account 303, which would cause simple ratios to functionalize a portion of distribution-related software into ASC. For example, in PacifiCorp’s Response to BPA Data Request ASC-09-PA-12, PacifiCorp stated that:

> The remaining $462 million consists of various computer hardware and software assets. Two assets dwarf the remaining assets – the Company’s accounting software – SAP ($159 million) and Customer Service System ($102 million) which support all areas of the Company and have been allocated on the PTD factor.

BPA decided to develop a general framework for use in software functionalization for Account 303 software. It did so to ensure that software costs will be functionalized in accordance with the 2008 ASCM and that similar types of software will receive the same functionalization for all exchanging utilities to the greatest extent possible. In addition, it should allow utilities that decided not to undertake the task of functionalization of Account 303 – Software an “easy to use” framework for functionalization.

BPA’s software cost functionalization framework functionalizes cost related to Enterprise Resource Planning ERP systems using the Labor ratio because the primary benefit of ERP systems is increased productivity of the utility’s work force. ERP systems are not installed to reduce line losses or increase heat rates of power generation equipment. While utilities may experience an increase in the productivity of assets, the cause is a result of the more accurate, timely and higher quality information provided to labor, thus resulting in a more efficient use of utility assets.

<u>Draft Decision:</u>

Enterprise Resource Planning software will be functionalized to Labor.

Table 4.2.15: Account 303, Intangible Plant Miscellaneous:
Enterprise Resource Planning Software
($000s)

		Total	PROD	TRAN	DIST
AS FILED					
Record Center Management Software	PTD	$291	$133	$56	$102
S A P	PTD	$160,206	$73,264	$30,930	$56,011
Enterprise Data Wrhse - Bi Rptg Tool	PTD	$1,660	$759	$321	$580
Disaster Recovery Project	PTD	$1,553	$710	$300	$543
DWHS - Data Warehouse	PTD	$1,158	$530	$224	$405
Enterprise Data Warehouse	PTD	$4,659	$2,131	$899	$1,629
Common Workstation & Login App	PTD	$1,633	$747	$315	$571
Close Down Ims And Move To New Platform	PTD	$514	$235	$99	$180
Novell Licenses	PTD	$258	$118	$50	$90
Quest Database Mgmt Tools	PTD	$525	$240	$101	$184
Sterling Software	PTD	$973	$445	$188	$340

		Total	PROD	TRAN	DIST
TIBCO Software	PTD	$3,716	$1,699	$717	$1,299
P8DM - Filenet P8	PTD	$3,199	$1,463	$618	$1,119
ORACLE 8i Database	PTD	$1,393	$637	$269	$487
Total		$181,739	$83,111	$35,088	$63,540
ADJUSTED					
Record Center Management Software	LABOR	$291	$129	$21	$140
S A P	LABOR	$160,206	$71,092	$11,796	$77,318
Enterprise Data Wrhse - Bi Rptg Tool	LABOR	$1,660	$737	$122	$801
Disaster Recovery Project	LABOR	$1,553	$689	$114	$750
DWHS - Data Warehouse	LABOR	$1,158	$514	$85	$559
Enterprise Data Warehouse	LABOR	$4,659	$2,067	$343	$2,248
Common Workstation & Login App	LABOR	$1,633	$725	$120	$788
Close Down Ims And Move To New Platform	LABOR	$514	$228	$38	$248
Novell Licenses	LABOR	$258	$114	$19	$124
Quest Database Mgmt Tools	LABOR	$525	$233	$39	$253
Sterling Software	LABOR	$973	$432	$72	$469
TIBCO Software	LABOR	$3,716	$1,649	$274	$1,793
P8DM - Filenet P8	LABOR	$3,199	$1,420	$236	$1,544
ORACLE 8i Database	LABOR	$1,393	$618	$103	$672
Total		$181,739	$80,647	$13,382	$87,710

4.2.16. Schedules 1 & 3 - Accounts 182.3, 186, 253, and 254:

Statement of Issue:

What is the correct functionalization of Accounts 182.3, 186, 253, and 254–

Other Regulatory Assets (Account 182.3), Miscellaneous Deferred Debits (Account 186), Other Deferred Credits (Account 253), and Other Regulatory Liabilities (Account 254) that are not recovered in rate base at the juridictiona level?

Statement of Facts:

Direct is the default functionalization of Other Regulatory Assets (Account 182.3), Miscellaneous Deferred Debits (Account 186), Other Deferred Credits (Account 253), and Other Regulatory Liabilities (Account 254).

PAC uses its latest results of operations to allocate and then functionalize the assets and liabilities (Accounts 182.3,186, 253, and 254). This is then used to allocate and functionalize the total assets and liabilities (Accounts 182.3,186, 253, and 254) as reported in the 2006 FERC Form 1.

All line items not included in the latest results of operations (*not recovered in rate base at the juridictiona level*) were functionalized to Distribution/Other. They are then allocated to the Pacific Northwest based upon the relevant allocation factors.

Summary of Parties' Positions:

PAC functionalizes Accounts 182.3,186, 253, and 254, shown in the FERC Form on a line-by-line basis using Direct Analysis. All line items not included in the latest results of operations were functionalized to Distribution/Other. They are then allocated to the Pacific Northwest based upon the relevant allocation factors.

It is PAC position that a regulatory Asset or Liability that is not recovered in rate base would be allocated to Distribution,

Analysis of Positions:

Direct analysis should be performed on the assets and liabilities shown in utilities' FERC Form 1 data. A direct analysis should not exclude any of the subaccounts from the FERC Form 1. All subaccounts, regardless of whether they are in the utility's rate base, should be included.

PAC functionalizes Accounts 182.3,186, 253, and 254, shown in the FERC Form on a line-by-line basis using Direct Analysis.

Section 4.10.4 of the 2008 ASCM, provides that under no conditions can regulatory assets be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates.

Draft Decision:

Accounts 182.3, 186, 253, and 254– Other Regulatory Assets (Account 182.3), Miscellaneous Deferred Debits (Account 186), Other Deferred Credits (Account 253), and Other Regulatory Liabilities (Account 254) will be functionalized based on PACS direct Analysis.

BPA agrees with PACs functionalization of accounts 182.3, 186, 253, and 254 for all line items not included in the latest results of operations and not in rate base should be functionalized to Distribution/Other.

4.2.17. Account 182.3 - Other Regulatory Assets: Account 1823040 - Oregon's Electric Restructuring Law

Statement of Issue:

Should assets that are not allocated to the PNW region in detail be allocated to Oregon in the summation calculation - Account 1823040 (Oregon's Electric Restructuring Law)*?*

Statement of Facts:

This account encompasses costs related to Oregon's Electric Restructuring Law.

PAC functionalized Account 1823040 (Oregon's Electric Restructuring Law) to Production

This account encompasses costs related to Oregon's Electric Restructuring Law.

PACs explanation of the items was not sufficiently clear to allow an understanding of the software's purposes and therefore the applicability of the functionalization.

PAC states in its response to Issue 23 that Oregon's Electric Restructuring Law allows a customer the choice of electricity producer. This asset represents the cost of allowing a customer his choice of electricity producer and is thus functionalized to Production.

Summary of Parties' Positions:

PAC argues that Oregon's Electric Restructuring Law allows a customer the choice of electricity producer. This asset represents the cost of allowing a customer his choice of electricity producer and is thus functionalized to Production.

Analysis of Positions:

PAC states in its response to Issue 23 that "BPA erroneously describes the account at issue and misunderstands the result of operations report. In the result of operations report, costs are allocated to the State, FERC or Other jurisdictions. If costs are allocated to a State, then such costs are included in the calculation of the revenue requirement for that State. State-specific costs may also be recovered from a State through a supplemental schedule. In that case, those costs will be allocated to Other in the result of operations report to insure that PAC does not recover the costs twice from Oregon ratepayers."

PAC stated that "Oregon's Electric Restructuring Law allowed a customer the choice of electricity producer. This asset represents the cost of allowing a customer his choice of electricity producer and is thus functionalized to production."

PAC contends Oregon's Electric Restructuring Law allows a customer the choice of electricity producer and therefore the cost of allowing a customer his choice of electricity producer should be functionalized to Production. The costs associated with Oregon's Electric Restructuring Law, however, relate to the retail side of the business and do not pertain to the production or transmission of electricity.

It is not clear to BPA how Oregon's Electric Restructuring Law costs relate to production or transmission functions of PAC. The costs associated with Oregon's Electric Restructuring Law reflect the implementation costs of a change in the regulatory structure and its effects are primarily in the billing and customer service functions. This law is directly related to a retail customer's choice and is not a cost of production and/or transmission of electricity.

Draft Decision:

Costs associated with the Oregon's Electric Restructuring Law will be functionalized to Distribution.

Table 4.2.17: Account 182.3 - Other Regulatory Assets:
Account 1823040
($000s)

		Total	Oregon	Washington	Idaho
AS FILED					
	Production	5014	$5,014		
ADJUSTED					
	DIST	5014	$5,014		

4.2.18. Account 253 - Other Deferred Credits: Sunnyside Cogeneration Bonds, Deferred Credits – Right of way, Deseret Power Security Deposits, and Centralia Environmental Liabilities

Statement of Issue:

Should PAC adjust the FERC Form 1 data for any expenses to conform to the Distribution functionalization?

Statement of Facts:

PACs filing functionalized all Regulatory Assets and Liabilities not included in PAC's regulated rate base to Distribution. It is not clear that the income statement accounts associated with these Credits are functionalized to distribution, e.g., Sunnyside Cogeneration appears in Account 555.

PacifiCorp also noted that page 269 of the FERC Form 1 includes no income associated with Sunnyside Cogeneration Bonds, i.e., the balance at the beginning of the year and at the end of the year is the same. The Sunnyside expense in Account 555 is unrelated to the Sunnyside Bond in Account 253. As the Company said in response to BPA Data Request 26, this account is "balance sheet only, not amortized."

Summary of Parties' Positions:

PAC supports the functionalization of this account to Distribution.

Analysis of Positions:

PACs explanation of these accounts indicates they are Regulatory Assets and Liabilities that are not included in PACs regulated rate base. Section 4.10.4 of the 2008 ASCM, provides that under no conditions can regulatory assets be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates.

Draft Decision:

Account 253 - Other Deferred Credits: Sunnyside Cogeneration Bonds, Deferred Credits – Right of way, Deseret Power Security Deposits, and Centralia Environmental Liabilities will be functionalized to Distribution.

4.2.19. Account 253 - Other Deferred Credits: Software License Payments – Microsoft

<u>Statement of Issue:</u>

What is the correct functionalization of Account 253 - Other Deferred Credits Software License Payments – Microsoft?

<u>Statement of Facts:</u>

As described in the Company's response to BPA ASC-09-PA/PacifiCorp Data Request 37, costs associated with "289530 Software License Payments – Microsoft are used to defer software licenses asset. It should be functionalized PTD."

The functionalization of a software system should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM.

When direct analysis is used, there is a requirement for a clear description and justification for the functionalization of all accounts and sub-accounts.

PACs explanation of the items was not sufficiently clear to allow an understanding of the software's purposes and therefore the applicability and justification of the functionalization to PTD.

<u>Summary of Parties' Positions:</u>

PAC contends that costs associated with "289530 Software License Payments – Microsoft should be functionalized to PTD.

<u>Analysis of Positions:</u>

The functionalization of a software system should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM.

When direct analysis is used, there is a requirement for a clear description and justification for the functionalization of all accounts and sub-accounts.

The software BPA has classified as Software License Payments – Microsoft is more accurately functionalized to the operation it supports, which is PACs employees. Therefore, the Labor ratio more accurately reflects the appropriate functionalization.

<u>Draft Decision:</u>

Account 253 - Other Deferred Credits 'Software License Payments – Microsoft will be functionalized to Labor.

Table 4.2.19: Account 253 - Other Deferred Credits:
Software License Payments – Microsoft
($000s)

		Prod	Tran	Dist
	Oregon			
PTD	$154	($71)	($30)	($54)
	Washington			
PTD	-$41	($19)	($8)	($14)
	Idaho			
PTD	-$32	($15)	($6)	($11)

		Prod	Tran	Dist
	Oregon			
LABOR	-$154	($68)	($11)	($74)
	Washington			
LABOR	-$41	($18)	($3)	($20)
	Idaho			
LABOR	-$32	($14)	($2)	($15)

4.2.20. Account 253 - Other Deferred Credits: *American Electric Power CRP*

Statement of Issue:

What is the correct functionalization of Account 253 - Other Deferred Credits American Electric Power CRP?

Statement of Facts:

As described in PAC's response to Issue 29, American Electric Power CRP is incorrectly functionalized to Production in the Company's filing. It is related to a Transmission Service Deposit (*see* FERC Form 1, page 269, line19) and should be functionalized to Transmission.

Summary of Parties' Positions:

PAC supports the functionalization of this account to Transmission.

Analysis of Positions:

PAC's explanation of the American Electric Power CRP indicates that the account is transmission-related and should be functionalized to Transmission.

Draft Decision:

Account 253 - Other Deferred Credits American Electric Power CRP will be functionalized to Transmission.

Table 4.2.20: Account 253 - Other Deferred Credits:
American Electric Power CRP
($000s)

	Oregon	Wash	Idaho
AS FILED			
	Prod	Prod	Prod
American Electric Power CRP	$ (3,610)	$ (1,031)	$ (841)
ADJUSTED			
	Tran	Tran	Tran
American Electric Power CRP	$ (3,610)	$ (1,031)	$ (841)

4.2.21. Account 253 - Other Deferred Credits: DEF REV-DUKE/HERMISTON GAS SALE NOVATION

Statement of Issue:

What is the correct functionalization of Account 253 - Other Deferred Credits Def Rev-Duke/Hermiston Gas Sale Novation*?*

Statement of Facts:

As described in the PAC's response to Issue 29, the Def Rev-Duke/Hermiston Gas Sale Novation is functionalized to Production in the Company's filing because the two contra accounts are Accounts 547 and 555, which are both production expense accounts.

As described in the Company's response to BPA ASC-09-PA/PacifiCorp Data Request 37:

"289025 Def Rev-Duke/Hermiston Gas Sale Novation - Payment is for the assignment of the gas purchase agreement for Hermiston. The amount in this account is the amount received less monthly amortization. It should be functionalized to PROD"

Summary of Parties' Positions:

PAC supports the functionalization of this account to Production.

Analysis of Positions:

The functionalization of a deferred credit should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM.

PAC's explanation of the Def Rev-Duke/Hermiston Gas Sale Novation indicates that the account is production (gas purchase)-related and should be functionalized to Production.

Draft Decision:

Account 253 - Other Deferred Credits Def Rev-Duke/Hermiston Gas Sale Novation *will be functionalized to Production*.

There is no change to the functionalization.

4.3. SCHEDULE 1A: Cash Working Capital

No direct adjustment.

4.4. SCHEDULE 2: Capital Structure and Rate of Return

No direct adjustment.

4.5. SCHEDULE 3: Expenses

No direct adjustment.

4.6. SCHEDULE 3A: Taxes - No Adjustments

No direct adjustment.

4.7. SCHEDULE 3B: Other Included Items

4.7.1. Schedule 3B - Other Items Account 456 - Other Electric Revenues: *OTH EL/EXCL WHEEL & MISC OTHER REV*

Statement of Issue:

What is the correct functionalization of Account 456 - Other Electric Revenues (Oth El/Excl Wheel & Misc Other Rev)?

Statement of Facts:

As described in PAC's response to BPA ASC-09-PA/PacifiCorp Data Request 40 and Issue 32:

> Oth El/Excl Wheel account is "Other electric revenue excluding wheeling revenue." Misc Other Rev account is miscellaneous other revenue. They consist of electric "revenues derived from electric operations not included in any of the foregoing accounts" (Accounts 450, 451, 453 – 455). They also exclude "revenues from transmission of electricity of others over transmission facilities of the utility." These two accounts are directly assigned to each state and thus must be functionalized to distribution. (See Response to BPA Data Request 3.) Based on the Revised Protocol only costs associated with distribution function can be allocated to the states.

Summary of Parties' Positions:

PAC supports the functionalization of this account to Distribution.

Analysis of Positions:

The functionalization of an account should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM.

The costs that are allocated to the PNW states are based on the "Revised Protocol" and are only distribution-related costs.

Draft Decision:

Account 456 - Other Electric Revenues (Oth El/Excl Wheel & Misc Other Rev) will be functionalized to Distribution.

4.7.2. Schedule 3B - Other Items Account 456 - Other Electric Revenues: *Use Of Facil Rev*

Statement of Issue:

What is the correct functionalization of Account 456 - Other Electric Revenues 456.21 - Use Of Facil Rev?

Statement of Facts:

As described in PACs response to BPA ASC-09-PA/PacifiCorp Data Request 28 and 40 and Issue 30, "The Company recommends that the Use Of Facil Rev (Other Companies Use of the Company's Transmission and Distribution) account be functionalized to TD."

Summary of Parties' Positions

PAC supports the functionalization of this account to TD.

Analysis of Positions:

The functionalization of an account should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM.

PACs description of the account confirms that the revenues associated with the account are related to the Company's Transmission and Distribution assets and therefore should be functionalized to Transmission and Distribution.

Draft Decision:

Account 456 - Other Electric Revenues 456.21 - Use Of Facil Rev will be functionalized to Transmission and Distribution.

There is no change to the functionalization.

4.8. SCHEDULE 4: Average System Cost

No direct adjustment.

5. SUPPORTING DOCUMENTATION:

5.1. Purchased Power and Sales for Resale

See book-outs and price spread.

5.2. Salaries and Wages

No direct adjustment.

5.3. **Labor Ratios**

No direct adjustment.

5.4. **Distribution Loss Factor**

No direct adjustment.

5.5. **ASC FORECAST MODEL:**

5.5.1. General Errors in the ASC Appendix 1 and ASC Forecast Model

Statement of Issue:

Did PAC properly complete and enter correct values and modify the Appendix 1 template and ASC Forecast Model?

Statement of Facts:

PAC made an error in completion of the Appendix 1 template which was not discovered by BPA staff until the final quality control review of the ASC Draft Report, Appendix 1 and ASC Forecast model. The error was caused by complexities unique to PAC and was a result of the PACs Jurisdictional allocation of costs to the PNW and then the summing of the state allocation to the total PNW.

PAC used Direct functionalization for accounts Acquisition Adjustments (Electric), Miscellaneous Deferred Debits, Other Deferred Credits, and Other Regulatory Liabilities in the Oregon Rate Base, Washington Rate Base and Idaho Rate Base, but did not change the functionalization code to Direct in the Sch 1- Rate Base tab. The forecast model utilizes the functionalization code from the Sch 1- Rate Base tab. Therefore when these accounts are imported into the forecast model they are functionalized to distribution for the Exchange period ASC determination.

Summary of Parties' Positions:

No parties submitted comments on this issue.

Analysis of Positions:

Table 1 of the 2008 ASCM provides that the functionalization method for this account is Distribution with no optional functionalization. However, the 2008 ASCM allows utilities to perform a direct analysis on any account that contains conservation program costs.

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.

Because utilities can perform a direct analysis on Acquisition Adjustments (Electric), Miscellaneous Deferred Debits, Other Deferred Credits, and Other Regulatory Liabilities, BPA advocates adjusting Sch 1- Rate Base tab to reflect the direct analysis performed in the state specific tabs.

Draft Decision:

BPA amended PACs Appendix 1 template to reflect the functionalization code to direct.

Table 5.5.1: Appendix 1 Template and Forecast Model: *Functionalization*

As-Filed							
Acquisition Adjustments (Electric)	114	DIST	DIST	$65,501,139			$65,501,139
Miscellaneous Deferred Debits	186	DIST	DIST	$20,023,847			$20,023,847
Other Deferred Credits	253	DIST	DIST	$25,541,252			$25,541,252
Other Regulatory Liabilities	254	DIST	DIST	$29,969,799			$29,969,799
ADJUSTED							
Acquisition Adjustments (Electric)	114	DIRECT	DIST	$65,501,139	$65,501,139	$0	$0
Miscellaneous Deferred Debits	186	DIRECT	DIST	$20,023,847	$19,148,701	$0	$875,146
Other Deferred Credits	253	DIRECT	DIST	$25,541,252	$5,895,251	$5,498,549	$14,147,451
Other Regulatory Liabilities	254	DIRECT	DIST	$29,969,799	$115,242	$48,652	$29,805,905

5.6. Purchased Power Expenses; and Account 447, Sales for Resale

5.6.1. Account 555, Purchased Power Expenses; Account 447, Sales for Resale; Price Spread

Statement of Issue: Book outs

How should book-outs and trading adjustments be treated for calculations of purchased power expense and sales for resale revenue and the price spread calculation?

Statement of Facts:

PAC is reducing the amount of its purchased power expense and sales for resale revenue by book-outs and trading adjustments. It appears that the other utilities do not.

The inclusion or exclusion of book-outs and trading adjustments in purchased power and sales for resale numbers affects the price spread calculation. BPA is considering whether it is appropriate to remove these adjustments when performing the price spread calculation and the ASCs.

Avista, Idaho Power, NorthWestern, PacifiCorp & Portland General Electric (PGE)

Avista, Idaho Power, NorthWestern, PacifiCorp & PGE issue list proposal filed February 25, 2009, stated that the IOUs support a consistent reporting of purchase power expenses and sales for resale among the exchanging utilities for the determination of price spread. If Bonneville determines the amounts used to calculate each company's price spread and reported in the FERC Form 1 should be without book-outs the IOUs agree to report and calculate accordingly.

Puget Sound Energy (PSE)

PSEs issue list proposal filed February 25, 2009, stated that PSE supports the use of the price spread, and the calculation of the price spread should be the same across all utilities. PSE understands that the objective of the price spread is to reflect the individual utility's experience in the wholesale market. Introducing differences in the calculation from utility to utility introduces mare than just market differences and may distort the result when compared across utilities. Such inconsistencies in the data input to the calculation of the price spread should be avoided.

Snohomish County PUD

Snohomish supports consistent reporting of purchase power expenses and sales for resale among the exchanging utilities for the determination of price spread. If Bonneville determines the amounts used to calculate each company's price spread as reported in the FERC Form 1, it should be without bookouts.

Summary of Parties' Positions:

The IOUs support a consistent reporting of purchase power expenses and sales for resale among the exchanging utilities for the determination of price spread. If Bonneville determines the amounts used to calculate each company's price spread and reported in the FERC Form 1 should be without book-outs the IOUs agree to report and calculate accordingly.

Analysis of Positions:

Both BPA and IOUs support a consistent reporting of purchase power expenses and sales for resale among the exchanging utilities for the determination of price spread.

Draft Decision:

BPA re-estimated the price spread for PAC.

Table 5.6.1.a: Account 555, Purchased Power Expenses; Account 447, Sales for Resale: Price Spread – As-filed

	327 Purchase Power '05	327 Purchase Power '06	327 Purchase Power '07
RQ	-	-	-
LF	86,311,773	93,368,189	67,135,341
IF	32,633,176	26,940,730	36,436,305
SF	448,874,755	629,255,096	74,248,365
LU	96,384,996	104,395,350	126,251,545
IU	$13,681,048	$17,715,091	$13,169,435
OS	$13,381,110	$24,738,081	$28,040,914
EX	$(1,009,066)	$9,904,598	$14,618,209
NA	$ -	$5,370,832	$(11,569,856)
AD	$(360,155,268)	$(571,010,776)	$(721,333,679)

	327 Purchase Power '05	327 Purchase Power '06	327 Purchase Power '07
RQ	-	-	-
LF	1,984,555.02	2,094,727.35	1,291,567.05
IF	596,737.89	490,383.53	572,201.04
SF	7,569,993.87	11,778,136.20	13,462,610.22
LU	2,316,253.15	2,408,570.06	,842,681.07
IU	182,709.86	228,118.65	175,341.78
OS	320,679.28	546,879.39	517,896.56
EX	-	-	-
NA	-	2,593.14	(1,615.77)
AD	(6,381,434.43)	(10,928,717.42)	(13,376,303.48)

	310-311SalesforResale'05	310-311SalesforResale'06	310-311SalesforResale'07
RQ	$3,059,692	$3,204,674	$3,153,905
LF	$92,511,215	$91,819,049	$61,617,880
IF	$5,692,330	$5,329,583	$18,033,298
SF	$500,778,779	$760,964,082	$987,165,133
LU	$10,646,497	$11,269,571	$11,358,283
IU	$275,691	$275,518	$229,349

	310-311SalesforResale'05	310-311SalesforResale'06	310-311SalesforResale'07
RQ	86,211.06	89,457.19	86,834.70
LF	1,976,611.11	1,976,556.45	1,312,198.42
IF	144,411.99	127,192.06	324,885.47
SF	9,272,446.86	14,165,897.21	17,104,411.68
LU	247,096.78	262,476.87	256,848.01
IU	7,255.03	7,250.48	6,035.51

	310-311SalesforResale'05	310-311SalesforResale'06	310-311SalesforResale'07		310-311SalesforResale'05	310-311SalesforResale'06	310-311SalesforResale'07
OS	$2,076,721	$(2,303,403)	$(5,649,960)	**OS**	57,309.37	(41,670.47)	(92,885.53)
EX	$ -	$ -	$ -	**EX**	-	-	-
NA	$ -	$7,034,848	$(193,200)	**NA**	-	(50,740.09)	7,292.30
AD	$(359,939,888)	$(566,644,288)	$(720,886,961)	AD	(6,294,396.19)	(10,881,247.73)	(13,322,572.21)
Average PP Price	66.98	66.52	158.18				
Average Sales for Resale Price	47.08	59.21	70.65				
Spread from Mid Point	$9.95	$3.66	$43.77				
Mid-Point	$57.033	$62.867	$114.416				
Price Spread	**17.4%**	**5.8%**	**38.3%**				
Weighted Average Spread			**23.97%**				

Table 5.6.1.b: Account 555, Purchased Power Expenses; Account 447, Sales for Resale: Price Spread – ADJUSTED

	327 Purchase Power '05	327 Purchase Power '06	327 Purchase Power '07		327 Purchase Power '05	327 Purchase Power '06	327 Purchase Power '07
RQ	$ -	$ -	$ -	**RQ**	-	-	-
LF	$86,311,773	$93,368,189	$67,135,341	**LF**	1,984,555.02	2,094,727.35	1,291,567.05
IF	$32,633,176	$26,940,730	$36,436,305	**IF**	596,737.89	490,383.53	572,201.04
SF	$448,874,755	$629,255,096	$774,248,365	**SF**	7,569,993.87	11,778,136.20	13,462,610.22
LU	$96,384,996	$104,395,350	$126,251,545	**LU**	2,316,253.15	2,408,570.06	2,842,681.07
IU	$13,681,048	$17,715,091	$13,169,435	**IU**	182,709.86	228,118.65	175,341.78
OS	$13,381,110	$24,738,081	$28,040,914	**OS**	320,679.28	546,879.39	517,896.56
EX	$(1,009,066)	$9,904,598	$14,618,209	**EX**	-	-	-
NA	$ -	$5,370,832	$(11,569,856)	**NA**	-	2,593.14	(1,615.77)
AD	$(20,298,635)	$(1,805,791)	$2,049,678	**AD**	(6,487.21)	169.69	644.23

	310-311SalesforResale '05	310-311SalesforResale '06	310-311SalesforResale '07		310-311SalesforResale '05	310-311SalesforResale '06	310-311SalesforResale '07
RQ	$3,059,692	$3,204,674	$3,153,905	**RQ**	86,211.06	89,457.19	86,834.70
LF	$92,511,215	$91,819,049	$61,617,880	**LF**	1,976,611.11	1,976,556.45	1,312,198.42
IF	$5,692,330	$5,329,583	$18,033,298	**IF**	144,411.99	127,192.06	324,885.47
SF	$500,778,779	$760,964,082	$987,165,133	**SF**	9,272,446.86	14,165,897.21	17,104,411.68
LU	$10,646,497	$11,269,571	$11,358,283	**LU**	247,096.78	262,476.87	256,848.01
IU	$275,691	$275,518	$229,349	**IU**	7,255.03	7,250.48	6,035.51
OS	$2,076,721	$(2,303,403)	$(5,649,960)	**OS**	57,309.37	(41,670.47)	(92,885.53)
EX	$ -	$ -	$ -	**EX**	-	-	-

	310-311SalesforResale '05	310-311SalesforResale '06	310-311SalesforResale '07		310-311SalesforResale '05	310-311SalesforResale '06	310-311SalesforResale '07
NA	$ -	$7,034,848	$(193,200)	**NA**	-	(50,740.09)	7,292.30
AD	$(21,553,969)	$97,199	$(634,380)	AD	52,960.49	476.22	(3,466.43)
Average PP Price	55.93	53.72	58.58				
Average Sales for Resale Price	51.30	53.72	57.67				
Spread from Mid Point	$2.32	$0.00	$0.45				
Mid-Point	$53.612	$53.719	$58.124				
Price Spread	**4.3%**	**0.0%**	**0.8%**				
Weighted Average Spread			**1.11%**				

5.6.2. Statement of Issue: Residential Exchange Payment

Statement of Issue: Book outs

Should Residential Exchange Payments be included in Account 555 – Purchased Power?

Statement of Facts:

PAC accounts for the Residential Exchange Payments in Account 555 – Purchased Power. Residential Exchange Payments are not exchangeable and therefore cannot be included in the calculation of ASC or the Purchased Power and Sales for Resale spread calculation.

Summary of Parties' Positions

PAC supports the removal of Residential Exchange Payments from the calculation of ASC or the Purchased Power and Sales for Resale spread calculation.

Draft Decision:

BPA removed the Residential Exchange Payments from the calculation of ASC or the Purchased Power and Sales for Resale spread calculation.

6. OTHER ISSUES

6.1. Generic Issue List

In addition to the above-noted issues specific to IPC, BPA raised seven issues that may be "generic" to all utilities. Following are the issues, which were discussed with the parties during the Review Process. In general, the IOUs responded in unison. Puget Sound submitted additional comments. Franklin PUD and Snohomish PUD did not respond in writing; however, Snohomish voiced support for the IOUs' proposal during the generic issue list discussion at the workshop held on March 4, 2009.

6.1.1. SCHEDULE 1: Plant Investment/Rate Base: Account 303, Intangible Plant - Miscellaneous

Statement of Issue:

Whether BPA should adopt a common functionalization for similar types of software assets?

Statement of Facts:

During review of the ASC filings, BPA noticed that a direct analysis performed by the utilities resulted in different functionalizations for similar types of software. For example, metering and customer information system (CIS) software was functionalized to Distribution by PGE while Avista, IPC, PacifiCorp, Puget and NorthWestern functionalized such software using the PTD ratio. The direct analysis provide by utilities to support use of the PTD ratio to functionalize Account 303 – Software was minimal or non-existent.

The 2008 ASCM specifies that the default functionalization for Account 303 – Intangible Plant - Miscellaneous is Direct, with an option to Distribution.

Summary of Parties' Positions:

The parties generally support the idea of a consistent functionalization of similar types of software. In their February 25, 2009, response to BPA's Issue List the IOUs stated that:

> BPA should maintain consistency in the functionalization of these common types of programs, with costs greater than an identified threshold value, amongst utilities when calculating ASC. In our initial Appendix 1 filings the IOUs have not functionalized certain software the same, we are all in agreement that given a determination by BPA on the proper functionalization of these items the IOUs will support a consistent treatment.

However, parties filed separate responses concerning functionalization of software included in Account 303. For example, Puget filed separate comments on functionalization of Account 303 software arguing that:

> Functionalization of software assets should reflect the regulatory treatment of such software assets in jurisdictional ratemaking.
>
> In calculating ASCS, it may sometimes be appropriate for BPA to maintain consistency in the functionalization of similar types of software assets. In some cases, however, jurisdictional or cost differences may render a consistent or generic treatment insufficient. If BPA were to adopt common functionalization for similar types of software assets, such common functionalization should be a default from which a utility could opt out.

PacifiCorp's February 11, 2009, response to BPA's Issues List stated many times in response to a BPA issue concerning functionalization of a specific piece of software that the "functionalization of a software system should follow the functionalization of the operation it supports." PacifiCorp also offered a conflicting rationale in response to a BPA Issue with a specific piece of software. For example, PacifiCorp's response to functionalization of a Customer Information System argued that "[i]n determining the proper functionalization, the focus should be on what costs the Company is recovering using this computer software."

PGE's February 11, 2009, response to BPA's Issues List stated that:

> Account 303 contains many different types of software, some of which should be functionalized using allocation factors rather than directly assigned. The account consists of the following categories and cost assignments:
>
> - Function Specific – Direct assigned
> - Customer Service – Direct assigned to distribution then allocated
> - Environmental Compliance – PTD allocation of $55,350
> - General Ledger/Payroll – Labor allocation
> - Common T & D Software – O&M Allocation, 15% T, 85% D
>
> This allocation method is a hybrid that combines the use of direct assignment and allocation factors. It was developed with oversight from the Oregon Public Utility Commission and is used in PGE rate cases. In the ASC Sch. 3 Expense allocations, A&G expenses, Office Supplies and Office Expenses are assigned using a Labor allocation. To be consistent, General Ledger and Payroll software should also be assigned using a Labor allocation. For PGE, a combination of direct and allocated methods is the most efficient and accurate way to functionalize account 303.
>
> BPA should consider expanding their functionalization methodology to include the hybrid method described above. This method could prescribe a common functionalization based on the type of software. It would not apply a uniform allocation factor to the total of account 303.

NorthWestern Energy's February 11, 2009, response to BPA's Issues List argued that:

> NWE believes it appropriate to adopt a common functionalization for similar types of software assets and still allow an IOU the option to functionalize based on its unique accounting applications supported with adequate documentation.

Analysis of Positions:

Section VIII.B, Table 1 of the 2008 ASCM, provides that functionalization of Account 303 is direct analysis with an option to Distribution.

The 2008 ASCM states "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." *Id* at 16.

When utilities perform a direct analysis on an Account, they must submit sufficient documentation so that BPA can determine if the functionalization is reasonable. In addition, the 2008 ASCM states that "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." *Id.* at 17.

BPA's review of the initial ASC filings revealed that most utilities either used the PTD or Labor ratio to functionalize a majority of Account 303 software. However, the functionalization methodology and rationale for the direct analysis was non existent, or weak and not consistent among utilities. Some of the statements included by utilities to support functionalization of a specific piece of software using the PTD ratio used terms like "supports all functions of the company"[3] or "supports all areas of the company."[4] These catchall phrases, if taken to the extreme, could be used to rationalize using the PTD ratio to functionalize the entire ASC filing using the PTD ratio. Such simple statements do not constitute a valid direct analysis.

BPA and the parties generally support the concept that the functionalization of a software system should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM. While the concept is easy enough to understand, it is difficult to implement within the context of a utility's ASC filing because of how the software is recorded or listed in internal databases of software in the utility information systems and because of the sheer volume of the individual items of software.

For example, a utility may record its customer information system (CIS) as 'Customer Information System' or record it by the name of the vendor such as Oracle, Harris, SAP or Ventyx, or by the application name such as Xcellant, Peace, or ConsumerLinX. Repeating this disparate method of recording software in a utility database for a 1,000 or more unique software products that a typical utility may have and the task of functionalizing the software for an ASC filing is difficult and time consuming for a utility analyst that may not have familiarity with the software and how and where it is used within the utility. Given this difficulty, it is not surprising that most utilities and their regulatory commissions use a simple ratio, such as PTD or labor, to functionalize most or all of the software in Account 303. This approach works well for development of retail rates which incorporate most, if not all, production, transmission and distribution costs of the utility.

However, a utility's ASC may include only allowable production and transmission costs determined in accordance with the 2008 ASCM. Using the PTD or LABOR ratio for all software costs could result in an incorrect functionalization of costs. For example, the costs of certain software packages are very large relative to others in Account 303, which would cause simple ratios to functionalize a portion of distribution-related software into ASC. For example, in PacifiCorp's Response to BPA Data Request ASC-09-PA-12, PacifiCorp stated that:

> The remaining $462 million consists of various computer hardware and software assets. Two assets dwarf the remaining assets – the Company's accounting software – SAP ($159 million) and Customer Service System ($102 million)

---

[3] See, for example, Data Responses ASC-09 PA-BPA-12 and ASC-09-PS-BPA-6

[4] See, for example, Data Response ASC-09-PS-BPA-12, and Excel file E302,303,E399,Common 2006 filed.xls, DATA for ASC tab, column W.

which support all areas of the Company and have been allocated on the PTD factor.

BPA decided to develop a general framework for use in software functionalization for Account 303 software. It did so to ensure that software costs will be functionalized in accordance with the 2008 ASCM and that similar types of software would receive the same functionalization for all exchanging utilities to the greatest extent possible. In addition, it should allow utilities that decided not to undertake the task of functionalization of Account 303 – Software an "easy to use" framework for functionalization.

Draft Decision:

BPA will functionalize software systems to follow the operation they support or the labor expense that the software replaced. If a utility fails to provide adequate documentation, BPA will functionalize software systems to Distribution.

Below is a list that describes and categorizes the bulk of utility software, includes the accounts associated with utility software and the functionalization BPA will use for each type of software.

System Categories

- ***Customer/Marketing*** – this category includes such applications as customer information systems for residential, commercial, and industrial customer billing, energy and demand management systems, meter reading, call center operations, and customer relationship management systems.

    - *Customer Information System (CIS)* – systems that manage the residential and small commercial customer information, bill calculation and presentation, and payment processes. Distribution - Accounts 901-910.

    - *Industrial Billing* – systems that manage the large industrial customers, bill calculation and presentation processes. Distribution - Accounts 901-910.

    - *Energy and Demand Management Systems* – systems and software that design, administer, manage, track, and report on the utility's portfolio of Demand-Side Management (DSM) and Energy Efficiency (EE) programs. Production.

    - *Call Center Operations* - these systems manage the operations of customer call centers including telephony and data management and employee scheduling and performance management. Distribution - Accounts 901-910.

    - *Customer Relationship Management (CRM) System* – systems that manage information about the utility's customers. Distribution - Accounts 901-910.

    - *Advanced Meter Infrastructure (AIM) System* – systems that measure, collect and analyze energy usage from advanced devices through various communication media on request or on a pre-defined schedule. It also includes the infrastructure (e.g., hardware, software, communications, customer associated systems, etc.) and the meter data management system components. Distribution – Account 902.

- *Meter Reading System* – systems that manage the meter reading for residential and commercial customers. It includes meter route management and performs limited meter read validation. Distribution - Accounts 902.

➢ ***Employee Information*** **–** this category includes such applications as employee benefits, human resources, training, time entry, payroll, and compensation management systems.

- *Payroll System* – systems that calculate pay for employees and produces payments (checks or direct deposits). LABOR – Account 920.

- *Human Resources* – systems that maintain employee information required to pay employees and maintain individual employee personal and work-related information. LABOR – Account 920.

- *Training System* – systems that maintain information about all employee training requirements, schedules, certifications, courses, and update/recertification requirements. LABOR – Account 920.

- *Time Entry System* – systems that capture actual time and attendance information for employees. LABOR – Account 920.

- *Compensation Management System* – systems that optimize and automate the salary planning process and maintain information on salary history, company guidelines, employee performance and job aspirations. LABOR – Account 920.

➢ ***Facilities Management*** – this category includes such applications as generation operations and management, transmission operations and management, substation operations and management, geographic information systems, asset/facilities management, and computer-aid design systems.

- *Geographic Information System (GIS)* – systems that integrate hardware, software, and data for capturing, managing, analyzing, and displaying all forms of geographically referenced information. Distribution - Accounts 580-599.

- *Computer Aided Design (CAD)* – systems that use computers to aid in the design and particularly the drafting (technical drawing and engineering drawing) of a part or product, including entire buildings. It is both a visual (or drawing) and symbol-based method of communication whose conventions are particular to a specific technical field. Distribution - Accounts 580-599.

➢ ***Financial Information*** **–** this category includes such applications as accounts receivable, accounts payable, general ledger, treasury and cash management, debt management, operations and capital budget preparation and management, asset accounting, work order accounting, and cost accounting systems.

- *Enterprise Resource Planning (ERP) System* – systems that provide a common foundation for business accounting including common functions such as accounts payable, general ledger, and accounts receivable. Representative vendor solutions include: Lawson Enterprise Financial Management, Oracle B-Business Suite, PeopleSoft Enterprise Financial Management Solutions, and SAP ERP Financials. LABOR – Account 920.

- *Treasury and Cash Management* – systems that maintain information on the cash accounts, investments cash pooling, and banking operations. Representative vendor solutions include: Oracle Cash and Treasury Management Solution, SymPro LABOR – Account 920.

- *Debt Management* – systems that manage the debt owned by the utility including debt instruments, notes, bonds, commercial paper, and stocks. PTDG.

- *Budget Preparation* – systems that provide for the preparation of both the capital and operational budget. These systems are often incorporated in the ERP system (see above). LABOR – Account 920.

- *Asset Accounting* – systems that automate the continuing property records of the utility. PTDG.

- *Work Order Accounting* – systems that maintain an automated sub-ledger to the general ledger to account for work-in-progress accounting for both capital and operation and maintenance projects. PTDG.

- *Cost Accounting* – systems that provide a standard cost accounting capability for both capital projects and operations and maintenance activities. LABOR – Account 920.

➢ ***Management Information*** – this category includes such applications as executive information, key performance indicators, and data warehouse systems.

- *Executive Information* – systems that facilitate and support the information and decision-making needs of senior executives by providing easy access to both internal and external information relevant to meeting the strategic goals of the utility. LABOR – Account 920.

- *Key Performance Indicators* – systems that capture both internal and external information related to key business indicators for senior management. LABOR – Account 920.

- *Business Intelligence* – systems that provide historical, current, and predictive information about the operations of the utility. LABOR – Account 920.

➢ ***Market Operations and Trading*** – this category includes such applications as risk management, market simulation, market interface, transmission rights and access, transmission pricing and billing, wholesale billing and settlement, energy trading and tagging, and market dispatch systems.

- *Risk Management* – systems used to integrate loss data from a variety of sources to develop a comprehensive view of operational risk exposure to the utility. LABOR – Account 920.

- *Market Simulation* – systems used to provide a model of transmission and security-constrained optimization of the system resources against spatially distributed loads. These systems are used to produce realistic projections of market clearing prices and asset utilization levels across the transmission grid. Transmission.

- *Transmission Rights and Access* – systems that maintain data on the utility's transmission line rights and access policies. Transmission.

- *Transmission Pricing and Billing* – systems that, similar to the *Customer Information System* above, maintain information on transmission system customers, bill calculation and presentation, and payment processes. Transmission.

- *Wholesale Billing and Settlement* – systems that, similar to the *Customer Information System* above, maintain information on wholesale customers, bill calculation and presentation, and payment processes. LABOR – Account 920.

- *Market Dispatch* - LABOR – Account 920.

- *Energy Trading and Tagging* – systems that provide trade processing, risk control and invoicing, credit risk to manage credit exposure, collateral management, and counterparty evaluation. Representative vendor solutions include: Triple Point Technology's Commodity XL, Allegro, and ADICA's EMCAS system. Production.

➢ ***Planning Models*** – this category includes such applications as resource management, capacity plan, fuel plan, load forecast, purchased power, and financial/rate forecast systems. LABOR – Account 920.

➢ ***Resource Management*** – this category includes such applications as materials management, purchasing, warehouse management, inventory, fleet management, fuel management, and alternative energy supply systems.

- *Materials Management* – systems that maintain information on products, price lists, inventory receipts, shipments, movements, and counts within the utility, as well as to and from suppliers. These systems are often incorporated in the ERP system (see above). PTD.

- *Purchasing* – systems that automate the acquisition of goods and services. These systems are often incorporated in the ERP system (see above).   LABOR – Account 920.

- *Warehouse and Inventory Management* – systems that include the physical inventory, shipping, receiving, and picking of items, barcode labeling, and space management. These systems are often incorporated in the ERP system (see above). PTD – Account 163.

- *Fleet Management* – systems that provide for the management and maintenance of all vehicles and equipment used by the utility including scheduling maintenance and preventive maintenance. Distribution - Account 933.

- *Fuel Management* – systems that maintain information on fuel management for the utility's fleet operations. Distribution - Account 933.

- *Alternative Energy Supply* – systems that manage the availability of energy supply from alternative sources which may be outside the control of the utility. Production.

➢ ***System Operations*** – this category includes such applications as outage scheduling, system optimization, load control, generation control, SCADA, energy management, system dispatch, fault restoration, stability analysis, and state estimator systems.

- *Generation Control* – systems that regulate the power output of electric generators within a prescribed area in response to changes in system frequency, tie-line loading, and the relation of these to each other. Production.
- *Generation Operations and Management* – systems used to maximize plant operating income by optimizing output and heat rates and by reducing maintenance expenses. Production.

- *Substation Operations and Management* – systems used to monitor the operation of substations to maximize performance and ensure safe equipment operations. TD.

- *Supervisory Control And Data Acquisition (SCADA)* – systems that maintain the real-time, as-operated state of the electrical network, tracking remote control and local control operations, temporary network changes, and fault conditions. TD.

- *Energy Management (EMS)*– systems used to reduce energy losses, improve the utilization of the system, increase reliability, and predict electrical system performance as well as optimize energy usage to reduce cost. TD.

- *System Dispatch* – systems used to evaluate and optimize on an hour-ahead and day-ahead basis the dispatch of the utility's power plants to changing plant conditions, power markets, and contractual obligations. Production.

➢ ***Work Management*** – this category includes such applications as plant maintenance, work order, service order, outage management, trouble order, contractor management, and project management systems.

- *Plant Maintenance* – systems used to plan, manage, and evaluate the required major maintenance activities typically in generation facilities or other major facilities and substations. Production.

- *Work Order* – systems that manage longer-duration work, either capital or operations and maintenance frequently performed by multi-person crews. Distribution.

- *Service Order* – systems that manage the short-interval work of the utility typically performed by service crews. The system would include work scheduling, tracking, and order completion. Distribution.
- *Outage Management* – systems that prioritize restoration efforts based upon criteria such as locations of emergency facilities, size of outages, and duration of outages, extent of outages and number of customers impacted; calculate estimates of restoration times; provides information on crews needed and assisting in restoration; and predict the location of fuse or breaker that opened upon failure. Representative vendor solutions include: ABB, GE Energy, Intergraph, Oracle Utilities, and Trimble. Distribution.

➢ ***Miscellaneous Software*** **–** For software that is in general and widespread use throughout the utility such as Microsoft Office, Microsoft Exchange Server, Anti-Virus applications Adobe products, or for software where the functional nature cannot be determined and the cost of the software is less than 1% of the total cost in Account 303 – Software. LABOR

6.1.2. SCHEDULE 1: Account 182.3, Other Regulatory Assets; Account 254, Other Regulatory Liabilities

Statement of Issue:

Whether BPA should adopt a common functionalization for similar types of regulatory assets and liabilities?

Statement of Facts:

There is an inconsistency in the way the IOUs functionalize Deferred Pension, Pay and other labor-related Assets and Liabilities. PGE, Avista and NW use the Labor Ratio. IPC uses PTD. PSE and PacifiCorp functionalize these assets to Distribution. The issue is whether BPA should maintain consistency in the functionalization of deferred pension, pay and other labor-related assets and liabilities among utilities when calculating ASC.

Summary of Parties' Positions:

In PSE's February 25, 2009, response to BPA's Issue list, it stated that:

> Functionalization of regulatory assets and liabilities should reflect the regulatory treatment of such regulatory assets and liabilities in jurisdictional ratemaking.
>
> In calculating ASCs, it may sometimes be appropriate for BPA to maintain consistency in the functionalization of deferred pension, pay and other labor related assets and liabilities to the extent that regulatory treatment of the account is the same across utilities and jurisdictions. In some cases, however, jurisdictional or cost differences may render a consistent or generic treatment insufficient. If BPA were to adopt common functionalization for similar types of software assets, such common functionalization should be a default from which a utility could opt out.

Avista, Idaho Power, NorthWestern, PacifiCorp and PGE's February 25, 2009, joint response to BPA's Issue Lists stated that "BPA should maintain consistency in the functionalization of deferred pension, pay and other labor related assets and liabilities amongst utilities when calculating ASC. All of the IOUs agree that it is appropriate for purposes of determining a utility's ASC to functionalize these accounts by the LABOR ratio."

Analysis of Positions:

The 2008 ASCM ROD states that "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."* 2008 ASCM ROD at 149 (emphasis added).

Regulatory assets and liabilities exist in the balance sheets of electric utilities only because of the effects of regulation. FERC defines them as "assets and liabilities that result from rate actions [of] regulatory agencies." [5] The WUTC states that **"**regulatory assets are a creature of regulatory decisions made by state regulators or FERC. 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.*

Regulatory Assets and Liabilities, Accounts 182.3 and 254 in the FERC Uniform System of Accounts, were established in March of 1993 in FERC Order No. 552, which established uniform accounting treatment for allowances associated with the 1990 Clean Air Act. Order No. 552 also dealt more broadly with accounting for regulatory assets and liabilities for electric and gas utilities.[6]

Regulatory assets and liabilities are a subset of the larger issue of the difference between accounting for utilities that are subject to price regulation and Generally Accepted Accounting Principles (GAAP). The issue can be traced back to the Internal Revenue Act of 1954 which permitted use of accelerated depreciation for income tax purposes. In 1962, the Accounting Principles Board (precursor to FASB) issued Opinion No. 2, which dealt comprehensively with the issue of accounting for industries subject to price regulation, was prepared in response to questions surrounding the creation of investment tax credits by Congress. Opinion No. 2 stated that all companies are subject to GAAP, but that differences may arise, generally surrounding recognition of cost, for companies subject to price or rate regulation.[7]

Simply because a utility recovers the expense associated with a regulatory asset in rates does not mean that the regulatory asset is also included in a utility's rate base and earning a return.

After review of the parties' comments and the 2008 ASCM ROD, BPA believes that functionalization of Regulatory Assets and Liabilities is a two-step process. First, the regulatory

---

[5] 6 *See* §11.03[2], G. Hahne and G. Aliff, *Public Utility Accounting*, pages 11-5 (Mathew Binder 2005).
[6] Ibid. 11-5
[7] Ibid.

asset or liability must be a component of the utility's jurisdictional rate base. If the regulatory asset or liability is ***not*** in its jurisdictional rate base, then it is functionalized to distribution.

If the regulatory asset or liability ***is included*** in the utility's jurisdictional rate base, then and only then will the utilities be permitted to functionalize the regulatory asset or liability based on the functional nature of the item.

Draft Decision:

Following the Review Processes and publication of the Final ASC Reports for FY 2010-2011, BPA will work with the parties to develop a standard functionalization protocol for common types of regulatory assets and liabilities that are not included in the utility's jurisdictional rate base.

For the FY 2010-2011 ASC Filings, BPA will use consistent decision criteria for common types of Regulatory Assets and Liabilities.

6.1.3. Account 182.3, Other Regulatory Assets; Account 186, Miscellaneous Deferred Debits; Account 253, Other Deferred Credits; Account 254, Other Regulatory Liabilities

Statement of Issue:

Whether BPA should require a common functionalization for asset accounts that have a corresponding liability account? For example, whether pension costs in Accounts 182.3 and 254 should have the same functionalization?

Statement of Facts:

A direct analysis is required in the functionalization of Other Regulatory Assets (Account 182.3), Miscellaneous Deferred Debits (Account 186), Other Deferred Credits (Account 253), and Other Regulatory Liabilities (Account 254). A direct analysis should include maintaining a consistency in functionalization where there is an asset in either Account 182.3 or 186 and offsetting liabilities in either Account 253 or 254.

Summary of Parties' Positions:

Avista, IPC, NorthWestern, PacifiCorp and PGE's February 25, 2009, joint response to BPA's Issue Lists stated that "The IOUs agree that BPA should require that accounts that have a corresponding asset and liability account have the same functionalization."

PSE's February 25, 2009, Issue List stated that:

> Functionalization of Account 182.3 and Account 254 should reflect the regulatory treatment of such accounts in jurisdictional ratemaking.

> In calculating ASCs, it may sometimes be appropriate for BPA to maintain consistency in the functionalization of pension costs in Accounts 182.3and 254 to the extent that there is a direct relationship between an Account 182.3 asset and an Account 254 liability and each such asset and liability receives the same regulatory ratemaking treatment.
>
> However, the appropriate functionalization of both the Account 182 asset and the Account 254 liability should fall out of the Direct Analysis rather than be constrained by predetermined expectations. Direct Analysis should go beyond just the name or title of the account and reflect the purpose and reason why each account was established. Other than deferred taxes, PSE is unaware of off sets on a particular regulatory asset o liability being booked in opposing accounts. For example, PSE normally nets debits and credits (other than taxes) and books the net in the appropriate asset or liability account.

Analysis of Positions:

BPA and the parties agree that asset accounts that have a corresponding liability account should be functionalized consistently.

Draft Decision:

BPA will require a common functionalization for asset accounts that have a corresponding liability account. This includes Other Regulatory Assets (Account 182.3), Miscellaneous Deferred Debits (Account 186), Other Deferred Credits (Account 253), and Other Regulatory Liabilities (Account 254).

6.1.4. Various Other Regulatory Assets and Liabilities

Statement of Issue:

What should be the functionalization of Other Regulatory Assets and Liabilities that are not included in rate base by the regulatory authority? What should be the functionalization of the corresponding income statement accounts for the Regulatory Assets and Liabilities that are not included in rate base by the regulatory authority?

Statement of Facts:

There is an inconsistency between utilities in the functionalization of Regulatory Assets and Liabilities that are not included in the utility's jurisdictional rate base. Some items in these accounts are included in working capital for ratemaking purposes. There is a concern that the treatment of the income statement accounts for the Regulatory Assets and Liabilities are not consistent with the asset and liability treatment for ASC purposes.

For example, PacifiCorp and PSE functionalized all Other Regulatory Assets and Liabilities that are not in their jurisdictional rate base to distribution. IPC, PGE, and Avista functionalized several items in these same accounts, not included in their jurisdictional rate base based on the functional nature of the item.

Summary of Parties' Positions:

Avista, IPC, NorthWestern, PacifiCorp and PGE's February 25, 2009, Response to BPA's Issue List stated that "There should be consistency between utilities in the functionalization of Regulatory Assets and Liabilities when not included in rate base. Regulatory Assets and Liabilities not included in Rate Base have no effect on the Company's income statement. All entries affect only the balance sheet."

PSE's February 25, 2009, response to BPA's Issue List stated that:

> Functionalization of Other Regulatory Assets and Liabilities not included in rate base should reflect the regulatory treatment of such assets and liabilities in jurisdictional ratemaking.
>
> This issue illustrates an inconsistency that can exist in the Appendix 1 if an account on the balance sheet defaults to Direct Analysis, but the corresponding accounts on the income statement do not. To resolve this inconsistency, BPA should adjust the income statement to directly assign the component related to the balance sheet account. Forcing the balance sheet accounts to conform to the functional method used for the related income statement account is problematic because of the Direct Analysis default of the balance sheet account.
>
> With respect to the functionalization of balance sheet accounts for which the default functionalization is Direct Analysis, the utility should first determine the regulatory treatment of the balance sheet account. If the balance sheet account was directly included in rate base (i.e., the balance sheet account was included in rate base but not through the regulated working capital component of rate base calculation) for ratemaking purposes, the utility should further review the specific functional nature of the balance sheet account. If, however, the balance sheet account was either not included directly in rate base for ratemaking purposes or was included only via the regulated working capital calculation, the utility should functionalize the balance sheet account to DIST/Other.

Analysis of Positions:

The 2008 ASCM ROD states that "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.*" 2008 ASCM ROD at 149 (emphasis added).

Regulatory assets and liabilities exist in the balance sheets of electric utilities only because of the effects of regulation. FERC defines them as "assets and liabilities that result from rate actions regulatory agencies." [8] The WUTC states that **"**regulatory assets are a creature of regulatory

---

[8] 6 *See* §11.03[2], G. Hahne and G. Aliff, *Public Utility Accounting*, pages 11-5 (Mathew Binder 2005).

decisions made by state regulators or FERC. 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.*

Regulatory Assets and Liabilities, Accounts 182.3 and 254 in the FERC Uniform System of Accounts, were established in March of 1993 in FERC Order No. 552, which established uniform accounting treatment for allowances associated with the 1990 Clean Air Act. Order No. 552 also dealt more broadly with accounting for regulatory assets and liabilities for electric and gas utilities.[9]

Regulatory assets and liabilities are a subset of the larger issue of the difference between accounting for utilities that are subject to price regulation and Generally Accepted Accounting Principles (GAAP). The issue can be traced back to the Internal Revenue Act of 1954, which permitted use of accelerated depreciation for income taxes purposes. In 1962, the Accounting Principles Board (precursor to FASB) issued Opinion No. 2, which dealt comprehensively with the issue of accounting for industries subject to price regulation, was prepared in response to questions surrounding the creation of investment tax credits by Congress. Opinion No. 2 stated that all companies are subject to GAAP, but that differences may arise, generally surrounding recognition of cost, for companies subject to price or rate regulation.[10]

Simply because a utility recovers the expense associated with a regulatory asset in rates does not mean that the regulatory asset is also included in the utility's rate base and earning a return.

Regulatory assets and liabilities will eventually be moved from the balance sheet to the income statement through recognition of the revenue or expense. They are only recorded on the utility balance sheets because of regulation. BPA and its customers reviewed revenue and expense accounts in detail during the 2008 ASCM consultation process and the 2008 ASCM has functionalization rules for those accounts. BPA will not change the functionalization of an income statement account as a result of a direct analysis on regulatory assets and liabilities.

Draft Decision:

Regulatory assets and liabilities must be included in a utility's jurisdictional rate base in order to be included in rate base for ASC purposes. BPA will not change the functionalization rules of an income statement account as the result of a direct analysis of a regulatory asset or liability.

6.1.5. Account 555, Purchased Power Expenses; Account 447, Sales for Resale; Price Spread

Statement of Issue:

How should book-outs and trading adjustments be treated for calculations of purchased power expense and sales for resale revenue and the price spread calculation? Should the treatment be consistent across utilities?

---

[9] Ibid. 11-5
[10] Ibid.

Statement of Facts:

PacifiCorp reduced the amount of its purchased power expense and sales for resale revenue by book-outs and trading adjustments.

The inclusion of book-outs and trading adjustments in purchased power and sales for resale accounts affects the price spread calculation.

Summary of Parties' Positions:

Avista, IPC, NorthWestern, PacifiCorp and PGE's February 25, 2009, response to BPA's Issue List stated that "The IOUs support a consistent reporting of purchase power expenses and sales for resale among the exchanging utilities for the determination of price spread. If Bonneville determines the amounts used to calculate each company's price spread and reported in the FERC Form 1 should be without book-outs the IOUs agree to report and calculate accordingly."

PSE's February 25, 2009, response to BPA's Issue List stated that "PSE supports the use of the price spread, and the calculation of the price spread should be the same across all utilities. PSE understands that the objective of the price spread is to reflect the individual utility's experience in the wholesale market. Introducing differences in the calculation from utility to utility introduces mare than just market differences and may distort the result when compared across utilities. Such inconsistencies in the data input to the calculation of the price spread should be avoided."

Analysis of Positions:

Both BPA and the IOUs support a consistent reporting of purchase power expenses and sales for resale among the exchanging utilities for the determination of price spread.

Draft Decision:

Utilities shall not adjust their purchase power and sales for resale for the effects of book-outs and trading adjustments.

6.1.6. ASC Forecast Model: New Plant Additions – Natural Gas Prices

Statement of Issue:

Should BPA adopt a common natural gas price forecast in the ASC Forecast Model for all new natural gas-fired plant additions?

Statement of Facts:

Forecasted natural gas prices vary significantly between utilities that have new natural gas-fired generating resources coming on-line after the Base Period. None of the utilities submitted documentation or copies of firm natural gas supply contracts to support their projected natural gas prices.

The primary informational basis of the ASCM is the use of utility-specific FERC Form 1 historical data. Use of utility-specific forecast data is consistent with this approach.

Summary of Parties' Positions:

Avista, IPC, PGE, PacifiCorp and NWE's February 25, 2009, response to BPA's Issue List stated that:

> The IOUs propose that it is reasonable to use a third party gas price forecast in the determination of an exchanging utility's ASC. The IOUs believe that the third party gas price forecast that BPA uses would be appropriate or another publicly available gas price forecast. In addition, if a given exchanging utility desires to use a different gas price for their new resource it is understood that they will have to supply all necessary data in support of their alternative gas price forecast.

PSE's February 25, 2009, response to BPA's Issue List stated that:

> Natural gas price forecasts should reflect the regulatory treatment of natural gas price forecasts in jurisdictional ratemaking.
>
> In calculating ASCs, it may sometimes be appropriate for BPA to use a third party gas price forecast for the gas commodity component of fuel cost. If BPA were to use such a third party gas price forecast, BPA should then reflect basis or hub differences as adjustments to this commodity price. BPA should also make adjustments for firm gas transportation costs on a utility-by-utility, resource-specific basis. These transportation cost adjustments would reflect the extent to which firm gas transportation contracts are in place for the specific new resource. In some cases, however, jurisdictional or cost differences may render a third party gas price forecast insufficient. If BPA were to use a third party gas price forecast, such third party gas price forecast should be a default from which a utility could opt out.

The OPUCs March 3, 2009, response to BPA's Issue List recommended that BPA use:

> The natural gas forward market prices existing at the time of utility filings for nearest available Hub, such as Sumas, to account for the average commodity cost of fuel for new natural gas generating resources unless a utility demonstrates other commodity contractual prices for its new resource(s). This would have the affect of removing BPA and utility guesses when accounting for the commodity cost of fuel for new natural generating resources. Natural gas market price forecasts are by their very nature tenuous.

The OPUC also recommended:

> . . . [t]hat BPA add charges for pipeline transportation and any other known fuel related charges to this commodity cost of fuel. In this regard, utilities include both fixed (Reservation) and variable pipeline charges in their Account 547, Other Power – Fuel. It should be recognized pipeline charges calculated on a unit basis, for instance dollars per MMBtu, vary with capacity factor. For example, Northwest Pipeline's tariff currently shows a maximum reservation charge of about 38 cents per MMBTU/day firm

> receipt/delivery capacity. If a utility plant having firm pipeline transportation for all of its maximum daily operation normally operates at 25 percent, then this pipeline charge equates to an average cost of $1.52 per delivered MMBTU (38 cents at full operation divided by 25 percent actual operation). So, when accounting for new resource other power fuel costs, BPA should also utilize pipeline tariffs in deriving the pipeline cost of transporting natural gas fuel from hub to plant gate along with plant capacity information unless a utility demonstrates other contractual pipeline charges.

OPUCs March 10, 2009, response to issues reiterated the above statements and stressed the need that whatever forecast was chosen should be available to parties through discovery in order to allow the parties to consider the reasonableness of the forecast.

Snohomish supports a common natural price forecast that is used in the ASC Forecast Model. Snohomish would support the use (by BPA) of third-party forecasting for natural gas prices, rather than BPA internal staff.

Analysis of Positions:

All of the responding parties supported the option of adopting a common natural gas price forecast in the ASC Forecast Model for all new natural gas-fired plant additions. The parties suggested that an independent third party should supply the natural gas forecast.

The parties also supported the principle that the natural gas price forecast should include adjustments for basis or hub differences, and adjustments for firm gas transportation costs on a utility-by-utility, resource-specific basis.

The parties proposed that the use of a third party gas price forecast should not preclude a utility from using its own forecast.

BPA agrees with the parties that a common natural gas price forecast would be reasonable. To that end, BPA considered using several commercially-available natural gas price forecasts. Unfortunately, the commercially-available forecasts are proprietary. Generally, the companies that provide these forecasts do not allow BPA to provide these forecasts to companies that do not subscribe to their services.

BPA believes it is equally important to that the costs included in the calculation of utility ASCs be consistent with the costs included in the calculation of the PF Exchange rate. Using the natural gas price forecast used to develop BPA's rates achieves this consistency. In addition, it allows all parties to BPA's rate case to examine and critique the forecast.

Decision:

BPA will use the natural gas forecast used in the BPA rate case for new gas-fired resources in the ASC Forecast Model.

6.1.7. ASC Forecast Model – Capacity Factors

Statement of Issue:

Whether BPA should use common representative capacity factors in the ASC Forecast Model for estimating the operating costs and expected energy output for new plant additions.

Statement of Facts:

Projected capacity factors vary significantly between utilities for similar types of new resources, and the ranges are too wide to provide consistency among the utilities.

Summary of Parties' Positions:

PSE's February 25, 2009, response to BPA's Issue List stated that:

> Capacity factors for specific new resources should reflect the regulatory treatment of capacity factors in jurisdictional ratemaking.
>
> In calculating ASCs, it may sometimes be appropriate for BPA to use common, representative capacity factors in the ASC Forecast model. In some cases, however, jurisdictional or cost differences may render common, representative capacity factors insufficient. If BPA were to use common, representative capacity factors, such common, representative capacity factors should be a default from which a utility could opt out.

Avista, IPC, NorthWestern, PacifiCorp and PGE's February 25, 2009, response to BPA's Issue List stated that:

> The IOUs propose that they will use a capacity factor within the range of capacity factors listed below for new resources coming online during the rate period.

Resource Type	Capacity Factor
Combined Cycle CT	45% to 75%
Simple Cycle CT	1% to 30%
Wind	25% to 45%
Geothermal	greater than 90%

> Again, if a utility chooses to use capacity factor outside the above range for a new resource, the utility will have to supply complete justification and documentation for use of such a capacity factor.

After a discussion with the parties, BPA will defer a decision on this issue until after the FY 2010- FY 2011 ASC Review Process is completed so that it can devote more time to this complex issue. Developing representative projected capacity factors for new resources is not a trivial exercise. For new natural gas-fired resources, projected stream flows, electric market prices, natural gas prices and heat rates must be analyzed before representative capacity factors can be developed. For projected wind resources the Pacific Northwest region is just beginning a major expansion of a resource with little historical data to use as a benchmark for developing representative capacity factors. Based on the exceeding small amount of data on wind capacity factors BPA and parties reviewed, differences by location were observed, but more time and research needs to be devoted to this effort. BPA and some of parties believe that this issue should be deferred to future ASC filings to develop more robust estimates of projected capacity factors for new resources.

Some of the filing utilities submitted revised capacity factors which reduced somewhat the variance in capacity factors for new generating resources. Partly for this reason, it is reasonable to accept utilities' respective as-filed capacity factors in establishing FY 2010 ASCs.

<u>Draft Decision</u>:

The capacity factors submitted by each utility will be accepted for this FY 2010-2011 Review Process. BPA, however, makes no precedential decision at this time. The issue will be revisited in future ASC filings.

6.2. <u>ASC FORECAST MODEL: New Resource Additions during FY 2010-2011</u>

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December, 2007) to the end of the Exchange Period (September, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows 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.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information from the ASC Draft Report as adjusted by BPA after the ASC Review Process.

6.3. ASC Forecast Model Calculates the Contract System Cost: Depreciation and Purchased Power

Under the 2008 ASCM, the BPA-approved Base Period costs are escalated to the midpoint of the rate period/Exchange Period to calculate Exchange Period ASCs. For a two year rate period the costs are escalated to the midpoint for a 2-year rate period/Exchange Period

To accomplish this, the ASC Forecast Model calculates the Contract System Cost at the start of the rate period, October 2009, and the end of the rate period, September 2011. The midpoint ASC is then calculated as the average of the start of rate period and end of rate period Contract System Costs, divided by the average of the start of rate period and end of rate period Contract System Loads.

The ASC Forecast Model uses a similar method to calculate the short-term (ST) purchased power expense included in Contract System Cost. Purchased power expense for the first year of the Exchange Period, FY 2010, is calculated by multiplying the amount of ST MWh purchases for FY 2010 by the utility's FY 2010 purchase price. Purchased power expense for the second year of the Exchange Period, FY 2011, is calculated by multiplying the amount of ST MWh purchases for FY 2011 by the utility's FY 2011 purchase price. The purchased power expense included in the calculation of the midpoint ASC is the average of the FY 2010 and FY 2011 purchased power expense. At the same time, the ASC Forecast Model calculates a weighted average purchased power price for the rate period.

When the exchanging Utilities submitted their Appendix 1 filings in October 2008, they provided their forecasts of major new resource additions, including all associated costs. For new resources forecast to come on-line during the Exchange Period, all new resource costs except depreciation expense were included at the midpoint of the Exchange Period, October 1, 2010. To calculate the change in ST purchased power expense resulting from new generating resources or new purchased power contracts, the amount of ST power purchases for FY 2011 was decreased by the amount of MWH forecast to be provided by the new generating resource or purchased power contract. A new average 2-year average of ST purchased power MWhs was then calculated. The new 2-year average MWh value was multiplied by the 2-year weighted average purchased power price calculated above to get the new ST purchased power included in Contract System Cost.

During the ASC Review process, BPA examined how the costs of new resources added during the rate period were being included in a Utility's Contract System Cost. Further analysis revealed that, by using a new 2-year average of ST MWh purchases, only half of the reduction in purchased power expense was being removed from Contract System Cost. However, with the exception of the new resource's depreciation expense, the ASC Forecasting Model was including a full year's cost for the new generating resource or purchased power contract. To address this inconsistency, BPA determined that it would be more appropriate to include a full year's change in Contract System Cost resulting from new generating resources or purchased power contracts.

In order to capture the total reduction in purchased power expense, BPA revised the method to calculate ST purchased power expense when a new generating resource is added. Under the revised method, the forecast MWhs provided by the new resource are multiplied by the FY 2011 purchased power price to get the reduction in ST purchased power expense resulting from adding the new resource. This method assures that the entire reduction in purchased power expense is captured in Contract System Cost. BPA also included the new resource's full year depreciation expense in Contract System Cost in order to capture all the changes in cost resulting from adding new resources during the rate period/Exchange Period.

7. FY 2010-2011 ASC

Overall BPA adjustments, including all changes made to PacifiCorp's Appendix 1 filing, decreased PacifiCorp's CY 2007 ASC by $0.13/MWh. These changes increased PacifiCorp's FY 2010-2011 ASC by $5.09/MWh. PacifiCorp's ASC for FY 2010-2011, prior to the addition of any new resources, is $56.49/MWh.

8. REVIEW SUMMARY

This draft ASC determination is BPA's best estimate of PacifiCorp's FY 2010-2011 ASC based on the information and data provided by PacifiCorp to date, and based on the professional review, evaluation, and judgment of BPA's REP staff. BPA will solicit and review comments on this Draft Report and the Draft Reports of all other exchanging utilities' for FY 2010-2011. After review of such comments, BPA will make final ASC determinations used to calculate REP benefits for each exchanging utility for FY 2010-2011. Final ASC determinations will be published in July, 2009.

The as-filed Appendix 1 Filing, ASC Forecast Model and NLSL assessment, and supporting documentation submitted by PacifiCorp, used to calculate PacifiCorp's ASC can be viewed at BPA's REP website: http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

9. ADMINISTRATOR'S APPROVAL

I have examined PacifiCorp's ASC filing, as amended, and the administrative record of the ASC Review Process. Based on this review and the foregoing analysis of the issues, I certify that this ASC determination conforms to the 2008 ASC Methodology and generally accepted accounting principles, and fairly represents PacifiCorp's ASC.