FY 2009 AVERAGE SYSTEM COST DRAFT REPORT

FOR

Portland General Electric

Docket Number: ASC-09-PG-01
Effective Date: October 1, 2008

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

April 13, 2009

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1. FILING DATA

Utility: **Portland General Electric**
121 SW Salmon Street
Portland, Oregon 97201
http://www.portlandgeneral.com/

Parties to the Filing:

Investor Owned Utilities (IOUs):
- Avista Utilities (Avista)
- Idaho Power Company (IPC)
- NorthWestern Energy (NorthWestern or NWE)
- PacifiCorp (PAC)
- 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
- Oregon Public Utility Commission (OPUC)
- Washington Utilities and Transportation Commission (WUTC)

ASC Base Year: CY 2006

Effective Exchange Period: FY 2009 (October 1, 2008 – September 30, 2009)

Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine PGE’s ASC for FY 2009 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 June, 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 Analyses (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) 2006.

The table below summarizes CY 2006 Base Period ASCs based on (1) the ASC information filed by PGE on October 1, 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 the Exchange Period ASC, which is noted in subsequent tables.

Table 2.1: CY 2006 Base Period ASC
(Results of Appendix 1 calculations)

	October 1, 2008	**April 13, 2009**
	As Filed	**Draft Report**
Production Cost	$780,278,890	$826,087,010
Transmission Cost	108,758,429	103,314,757
(Less) NLSL Costs	15,957,669	15,957,669
Contract System Cost	**$873,079,649**	**$913,444,097**
Total Retail Load (MWh)	18,432,527	18,432,527
(Less) NLSL	868,172	868,172
Total Retail Load (Net of NLSL)	18,090,153	18,090,153
Distribution Losses	868,172	995,294
Contract System Load	**18,958,325**	**19,085,447**
CY 2006 Base Period ASC ($/MWh)	**46.05**	**47.86**

2.2. Exchange Period 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 2009). The forecast covers the period from the end of the Base Period (December, 2006) to the end of the Exchange Period (September, 2009). 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 to be purchased and used to meet a utility's retail load during the Exchange Period (FY 2009).

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 1, 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 2009 Exchange Period ASC				
Resource	**Port Westward**	**Biglow Canyon I**	**N.A.**	**N.A.**
On-Line Date	June 2007	December 2007		
Delta*	3.10	1.37		

Draft Report FY 2009 Exchange Period ASC				
Resource	**Port Westward**	**Biglow Canyon I**	**N.A.**	**N.A.**
On-Line Date	June 2007	December 2007		
Delta*	4.71	1.35		

*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 2009 Exchange Period ASC				
Resource	**Biglow Canyon II**	**Selective Water Withdrawal**	**N.A.**	**N.A.**
Expected On-Line Date	April 2009	April 2009		
Delta*	**1.85**	**.60**		

Draft Report FY 2009 Exchange Period ASC				
Resource	**Biglow Canyon II**	**N.A.**	**N.A.**	**N.A.**
Expected On-Line Date	June 2009			
Delta*	**1.85**	**0**		

*The Delta is the incremental change in the ASC as the new resources come on line. The Selective Water Withdrawal project did not meet the 2.5% of ASC Criteria so it was not included as a new resource for ASC purposes.

2.3. FY 2009 Exchange Period ASC for the Draft Report

The following table identifies the Exchange Period ASC as filed on October 1, 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 2.2.1: Exchange Period FY 2009 ASC ($/MWh)
Prior to New Resource Additions

Date	October 1, 2008 As-Filed	April 13, 2009 Draft Report
FY 2009	54.98	58.37

The amended Appendix 1 Filing, ASC Forecast Model, supporting documentation, and resource cost determination for the NLSL assessment used to calculate PGE's ASCs 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 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 ASCs 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 ASCM 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 2009</u>

Under the 2008 ASCM, utilities' ASCs are generally established prior to the calculation and payment of REP benefits. The ASC Review Process for FY 2009, however, has occurred during the Exchange Period in which the as-filed ASC is in effect. This is because the 2008 ASCM was completed in June of 2008, which did not allow the ASC Review Process to occur and establish final utilities' ASCs until after FY 2009 had begun. Therefore, the REP for FY 2009 is implemented based on as-filed ASCs, and payments are then trued up for the final ASCs determined by BPA. In the future, the ASC Review Process will occur before the beginning of the Exchange Period.

On October 1, 2008, exchanging utilities submitted ASC filings for the FY 2009 Exchange Period. The as-filed ASCs went into effect on an interim basis at that time and will be trued-up based on the results of the respective ASC Final Reports, which are scheduled for publication in June, 2009. All data were submitted using two Excel-based models: the Appendix 1 and the ASC Forecast Model. Additional 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 2009 (October 1, 2008, through September 30, 2009), the Base Period (CY 2006) 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 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 2009 ASCs are still in progress at this publication date. Upon completion of the formal reviews and final ASC determinations, BPA will publish, in June 2009, Final Reports 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, which 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 (CY 2006) ASC data forward to the Exchange Period, which in this case is FY 2009. 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 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 fiscal year for the FY 2009 Exchange Period 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 (CY 2006) to the end of the Exchange Period (FY 2009).

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 mid-point 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 IPC submitted its responses. No other party raised issues or commented on IPC's responses. Each issue pertains to the October 1, 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. Resolved Issues

The following issues contained on BPA's February 3, 2009 Issue List to PGE were resolved during the review of PGE's ASC filing.

1. Account 303 - Intangible Plant
2. Account 303 - Generic Direct Analysis Issue
9. Account 555 - Purchased Power – Non Trading Mark to Market
10. Account 555 - Purchased Power – Margin on Electric Financials
11. Account 555 - Purchased Power – Reserve Credit Trading Risk
12. ASC Forecast Model Generic Issue – Purchased Power Expense, Sales for Resale and Price Spread

4.3. Schedule 1: Plant Investment/Rate Base:

4.3.1. Account 182.3 Other Regulatory Assets: Asset Retirement Cost Balancing Account

Statement of Issue:

Has PGE properly calculated and appropriately functionalized its Other Regulatory Assets: Asset Retirement Cost (ARC) Balancing Account, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does PGE's documentation submitted *with its ASC filing constitute a valid Direct Analysis? Should the costs associated with asset cost retirement balancing account be functionalized using the PTD ratio?*

<u>Statement of Facts:</u>

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

In its Oct 1, 2008 ASC Filing, PGE used the PTD ratio to functionalize the asset retirement cost balancing account. No detail describing the costs was provided, so BPA was unable to determine if PTD was appropriate for this account.

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

In PGE's December 1, 2008 response to BPA's data request PGE stated "This balancing account accumulates production, transmission and distribution asset retirement costs for future collection in rates. As this account contains costs related to all three functions, it is functionalized to PTD." In response to BPA's question on whether the ARO Balancing Account was in rate base, PGE responded "These costs are related to production transmission and distribution plant and as such are properly recovered in PGE rates."

In their February 11, 2009 response to BPA's Issue List PGE said that "The amount functionalized for the Asset Retirement component of Account 182.3 is $9,399 for 2006 and zero for 2007. PGE is open to further investigation of the appropriate functionalization for this account." No additional information on this account was submitted by PGE.

<u>Analysis of Positions:</u>

PGE's asset cost retirement balancing account is a regulatory asset used to accrue changes in the Asset Retirement Obligations (ARO) between regulatory filings with the Oregon Public Utility Commission.

ARO are a balance sheet item added as a result of the issuance of Statement of Financial Accounting Standards (SFAS) No. 143 from the Financial Account Standards Board. SFAS 143 concerns accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS requires companies to record a liability at fair market value when a retirement obligation exists; provided fair value can be reasonably estimated even though it is years prior to the assets planned retirement. After the initial recognition of the ARO, the liability will change over time, so the obligation may be accrued to its present value each year. The long-term asset's capitalized cost is depreciated over its useful life.

PGE's 2006 FERC Form 1 stated that "At December 31, 2006, PGE's asset retirement obligations include $108 million associated with the Trojan plant, representing the present value of future decommissioning expenditures. Site specific AROs, totaling $15 million, have also been recognized for rate-regulated utility plant, consisting of the Boardman and Colstrip Units 3 and 4 coal plants, the Coyote Springs, Beaver, and Port Westward gas turbine plants, and the Bull Run hydro project. A $2 million conditional asset retirement obligation, resulting from the adoption and application of FIN 47 in 2005, has been recognized for the disposal cost of assets subject to specific environmental regulation, including costs related to treated pole disposal, mercury vapor light disposal, asbestos remediation, polychlorinated biphenyl (PCB) disposal, underground storage tank removal, and other miscellaneous disposal costs. A total of $9 million in AROs for non-utility property has also been recognized." *PGE FERC Form 1 at 123.33.*

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)

PGE's documentation and support did not show that PGE received a return on the ARO Balancing Account. PGE's response to BPA's data request only stated that such costs are "…properly recovered in PGE rates."

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." [1]

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.[2]

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.[3]

Just because a utility recovers the expense associated with a Regulatory Asset in rates does not mean that the Regulatory Asset is also included in PGE's rate base and earning a return.

Draft Decision:

Because PGE did not provide documentation showing that ARO Balancing Account was included in PGE's retail rate base, BPA will functionalize ARO Balancing Account to distribution.

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[1] 6 *See* §11.03[2], G. Hahne and G. Aliff, *Public Utility Accounting*, pages 11-5 (Mathew Binder 2005).
[2] Ibid. 11-5
[3] Ibid.

Table 4.3.1: Account 182.3 Other Regulatory Assets:
Asset Retirement Cost Balancing Account ($)

	Total	Production	Transmission	Dist/Other
As-Filed	9,399	3,359	709	5,152
BPA Adjusted	9,399	0	0	9,399

4.3.2. Account 182.3 Other Regulatory Assets: Pension Funding

Statement of Issue:

Has PGE properly calculated and appropriately functionalized its Other Regulatory Assets: Pension Funding, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does PGE's documentation submitted with its ASC filing constitute a valid Direct Analysis? Should the costs associated with Pension Funding be functionalized using the Labor ratio?

Statement of Facts:

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

In its Oct 1, 2008 ASC Filing, PGE used the Labor ratio to functionalize Pension Funding in Account 182.3. No detail describing the costs was provided, so BPA was unable to determine if Labor was appropriate for this item.

Summary of Parties' Positions:

In PGE's December 1, 2008 response to BPA's data request BPA-PG-07 PGE stated "Pension funding costs are incurred for employees in every functional area of PGE. Since these costs are associated with labor they are functionalized as Labor.

In response to BPA's question on whether the Pension Costs were in rate base, PGE responded "These costs are a liability and are not considered in rate base. Their treatment in a rate case depends on the financial circumstances of the pension fund at the time of the rate case. PGE's current rates included the forecasted level of pension funding expenses for 2007, according to the SFAS No. 158 accounting rule adopted 12/31/2006."

In their February 11, 2009 response to BPA's Issue List PGE said that "BPA should adopt a common functionalization for similar types of regulatory assets and liabilities. PGE believes that the Labor ratio properly functionalizes employee-related expenses, assets and liabilities." No additional information on this account was submitted by PGE.

Analysis of Positions:

SFAS No. 158 was issued by the Financial Accounting Standards Board (FASB) issued in September of 2006 requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity.

PGE's 2006 SEC 10K filing stated: "On December 31, 2006, PGE adopted SFAS No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, which requires that the funded status of pension and other postretirement plans be recognized, with the resulting adjustment recorded to the ending balance of Accumulated OCI on the Consolidated Balance Sheets. Postretirement costs are covered in rates charged to customers through 2006. The OPUC issued an accounting order that authorizes PGE to record a regulatory asset equal to the pretax charge against Accumulated OCI that would otherwise be required by recognition of the pension funded status under SFAS No. 158. As pension expense is recognized in future years, the regulatory asset will be reduced. See Note 2, Employee Benefits, for further information."[4]

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).

The documentation submitted by PGE in response to BPA's Data Requests and Issue List did not show that Pension Costs are included in PGE's rate base by the Oregon PUC. PGE's response to BPA's data request only stated that "PGE's current rates included the forecasted level of pension funding expenses for 2007, according to the SFAS No. 158 accounting rule adopted 12/31/2006."

Just because a utility recovers the expense associated with a Regulatory Asset in rates does not mean that the Regulatory Asset is also included in PGE's rate base and earning a return.

Decision:

Because PGE did not provide documentation showing that Pension Funding was included in PGE's retail rate base, BPA will functionalize Pension Funding to distribution.

[4] Portland General Electric 2006 SEC 10K filing, Page 100

Table 4.3.2: Account 182.3 Other Regulatory Assets: Pension Funding ($)

	Total	Production	Transmission	Dist/Other
As-Filed	73,265,064	22,777,955	3,837,655	46,649,454
BPA Adjusted	73,265,064	0	0	73,265,064

4.3.3. Account 182.3 Other Regulatory Assets: Postretirement Funding

Statement of Issue:

Has PGE properly calculated and appropriately functionalized its Other Regulatory Assets: Postretirement Funding, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does PGE's documentation submitted with its ASC filing constitute a valid Direct Analysis? Should the costs associated with Postretirement Funding be functionalized using the Labor ratio?

Statement of Facts:

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

In its Oct 1, 2008 ASC Filing, PGE used the Labor ratio to functionalize Postretirement Funding in Account 182.3. No detail describing the costs was provided, so BPA was unable to determine if Labor was appropriate for this item.

Summary of Parties' Positions:

In PGE's December 1, 2008 response to BPA's data request BPA-PG-07 PGE stated "Postretirement funding costs are incurred for employees in every functional area of PGE. Since these costs are associated with labor they are functionalized as Labor.

In response to BPA's question on whether the Postretirement costs were in rate base, PGE responded "These costs are treated as an expense. Their treatment in a rate case depends on the financial circumstances of the funding level at the time of the rate case. PGE's current rates included the forecasted level of pension funding expenses for 2007, according to the SFAS No. 158 accounting rule adopted 12/31/2006."

In their February 11, 2009 response to BPA's Issue List PGE said that "BPA should adopt a common functionalization for similar types of regulatory assets and liabilities. PGE believes that the Labor ratio properly functionalizes employee-related expenses, assets and liabilities." No additional information on this account was submitted by PGE.

Analysis of Positions:

SFAS No. 158 was issued by the Financial Accounting Standards Board (FASB) issued in September of 2006 requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity.

PGE's 2006 SEC 10K filing stated: "On December 31, 2006, PGE adopted SFAS No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, which requires that the funded status of pension and other postretirement plans be recognized, with the resulting adjustment recorded to the ending balance of Accumulated OCI on the Consolidated Balance Sheets. Postretirement costs are covered in rates charged to customers through 2006. The OPUC issued an accounting order that authorizes PGE to record a regulatory asset equal to the pretax charge against Accumulated OCI that would otherwise be required by recognition of the pension funded status under SFAS No. 158. As pension expense is recognized in future years, the regulatory asset will be reduced. See Note 2, Employee Benefits, for further information."[5]

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).

The documentation submitted by PGE in response to BPA's Data Requests and Issue List did not show that Postretirement costs are included in PGE's rate base by the Oregon PUC. PGE's response to BPA's data request only stated that "PGE's current rates included the forecasted level of pension funding expenses for 2007, according to the SFAS No. 158 accounting rule adopted 12/31/2006."

Just because a utility recovers the expense associated with a Regulatory Asset in rates does not mean that the Regulatory Asset is also included in PGE's rate base and earning a return.

Decision:

Because PGE did not provide documentation showing that Postretirement Funding was included in PGE's retail rate base, BPA will functionalize Postretirement Funding to distribution.

[5] Portland General Electric 2006 SEC 10K filing, Page 100

Table 4.3.3: Account 182.3 Other Regulatory Assets: Postretirement Funding ($)

	Total	Production	Transmission	Dist/Other
As-Filed	14,128,185	4,485,693	755,754	9,186,738
BPA Adjusted	14,128,185	0	0	14,128,185

4.3.4. Account 182.3 Other Regulatory Assets: Grid West Loans

<u>Statement of Issue</u>:

Has PGE properly calculated and appropriately functionalized its Other Regulatory Assets: Grid West Loans, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does PGE's documentation submitted with its ASC filing constitute a valid Direct Analysis? Should the costs associated with Grid West Loans be functionalized to Transmission?

<u>Statement of Facts</u>:

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

In its Oct 1, 2008 ASC Filing, PGE functionalized Grid West Loans in Account 182.3 to Transmission. No detail describing the costs was provided, so BPA was unable to determine if Transmission was appropriate for this item.

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

In PGE's December 1, 2008 response to BPA's data request BPA-PG-07 PGE stated "Grid West loans are the result of an attempt to organize a regional transmission organization for the NW transmission grid. These costs are functionalized as transmission."

In response to BPA's question on whether the Grid West loans were in rate base, PGE responded "In 2006, these costs were deferred for future collection, and will be in PGE's rates according to OPUC Order 06-483 dated 8/22/2006."

In their February 11, 2009 response to BPA's Issue List PGE said that "BPA should adopt a common functionalization for similar types of regulatory assets and liabilities. No additional information on this item was submitted by PGE.

<u>Analysis of Positions:</u>

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).

The documentation submitted by PGE in response to BPA's Data Requests and Issue List did not show that Grid West loans are included in PGE's rate base by the Oregon PUC. PGE's response to BPA's data request only stated that "In 2006, these costs were deferred for future collection, and will be in PGE's rates according to OPUC Order 06-483 dated 8/22/2006."

Just because a utility recovers the expense associated with a Regulatory Asset in rates does not mean that the Regulatory Asset is also included in PGE's rate base and earning a return.

Decision:

Because PGE did not provide documentation showing that the cost associated with Grid West loans was included in PGE's retail rate base, BPA will functionalize Grid West loans to distribution.

Table 4.3.4: Account 182.3 Other Regulatory Assets: Grid West Loans ($)

	Total	Production	Transmission	Dist/Other
As-Filed	1,330,468	0	1,330,468	0
BPA Adjusted	1,330,468	0	0	1,330,468

4.3.5. Account 182.3 Other Regulatory Assets: Boardman Power Cost Deferral

Statement of Issue:

Has PGE properly calculated and appropriately functionalized its Other Regulatory Assets: Boardman Power Cost Deferral, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does PGE's documentation submitted with its ASC filing constitute a valid Direct Analysis? Should the costs associated with Boardman Power Cost Deferral be functionalized to Production?

Statement of Facts:

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

In its Oct 1, 2008 ASC Filing, PGE functionalized Boardman Power Cost Deferral in Account 182.3 to Production. No detail describing the costs was provided, so BPA was unable to determine if Transmission was appropriate for this item.

Summary of Parties' Positions:

In PGE's December 1, 2008 response to BPA's data request BPA-PG-07 PGE stated "These costs are associated with replacement power due to a sustained outage of the Boardman coal plant that is located southwest of Boardman, Oregon. As this was a generation outage these costs are functionalized as production."

In response to BPA's question on whether the Boardman Power Cost Deferral was in rate base, PGE responded "These costs are collected in rates according to OPUC Order No. 07-049 dated 2/12/2007."

In their February 11, 2009 response to BPA's Issue List PGE said that "BPA should adopt a common functionalization for similar types of regulatory assets and liabilities. No additional information on this item was submitted by PGE.

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).

The documentation submitted by PGE in response to BPA's Data Requests and Issue List did not show that the Boardman Power Cost Deferral was included in PGE's rate base by the Oregon PUC. PGE's response to BPA's data request only stated that "These costs are collected in rates according to OPUC Order No. 07-049 dated 2/12/2007."

Just because a utility recovers the expense associated with a Regulatory Asset in rates does not mean that the Regulatory Asset is also included in PGE's rate base and earning a return.

Decision:

Because PGE did not provide documentation showing that the cost associated with Boardman Power Cost Deferral was included in PGE's retail rate base, BPA will functionalize Boardman Power Cost Deferral to distribution.

Table 4.3.5: Account 182.3 Other Regulatory Assets:
Boardman Power Cost Deferral ($)

	Total	Production	Transmission	Dist/Other
As-Filed	6,000,000	6,000,000	0	0
BPA Adjusted	6,000,000	0	0	6,000,000

4.3.6. Account 254 Other Regulatory Liabilities: Surplus CAA Allowances

Statement of Issue:

Has PGE properly calculated and appropriately functionalized its Other Regulatory Liabilities: Surplus CAA Allowances, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does PGE's documentation submitted with its ASC filing constitute a valid Direct Analysis? Should Surplus CAA Allowances be functionalized to Production?

Statement of Facts:

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

In its Oct 1, 2008 ASC Filing, PGE functionalized Surplus CAA Allowances in Account 254 to Production. No detail describing the costs was provided, so BPA was unable to determine if Production was appropriate for this item.

Summary of Parties' Positions:

In PGE's December 1, 2008 response to BPA's data request BPA-PG-010 PGE stated "This account contains surplus PGE Clean Air Act allowances. Since these are power supply related they are functionalized to production."

In response to BPA's question on whether the Surplus CAA Allowances were in rate base, PGE responded "These costs are collected in rates according to OPUC Order No. 552 dated 3/31/1992."

In their February 11, 2009 response to BPA's Issue List PGE said that "BPA should adopt a common functionalization for similar types of regulatory assets and liabilities. No additional information on this item was submitted by PGE.

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).

The documentation submitted by PGE in response to BPA's Data Requests and Issue List did not show that the Surplus CAA Allowances were included in PGE's rate base by the Oregon PUC. PGE's response to BPA's data request only stated that "These costs are collected in rates according to OPUC Order No. 552 dated 3/31/1992

<u>Decision</u>:

Because PGE did not provide documentation showing that the Surplus CAA Allowances were included in PGE's retail rate base, BPA will functionalize Surplus CAA Allowances to distribution.

Table 4.3.6: Account 254 Other Regulatory Liabilities: Surplus CAA Allowances ($)

	Total	Production	Transmission	Dist/Other
As-Filed	486,590	486,590	0	0
BPA Adjusted	486,590	0	0	486,590

4.3.7. Account 254 Other Regulatory Liabilities: Interest on Portland Energy Solutions Note

<u>Statement of Issue</u>:

Has PGE properly calculated and appropriately functionalized its Other Regulatory Liabilities: Interest on Portland Energy Solutions Note, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does PGE's documentation submitted with its ASC filing constitute a valid Direct Analysis? Should Interest on Portland Energy Solutions Note be functionalized to Production?

<u>Statement of Facts</u>:

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

In its Oct 1, 2008 ASC Filing, PGE functionalized Interest on Portland Energy Solutions Note in Account 254 to Production. No detail describing the costs was provided, so BPA was unable to determine if Production was appropriate for this item.

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

In PGE's December 1, 2008 response to BPA's data request BPA-PG-010 PGE stated "This account consists of interest on a promissory note for an organization operating energy efficiency programs. Energy efficiency saves kWh that would otherwise be generated. Therefore it is functionalized as production."

In response to BPA's question on whether the Portland Energy Solutions Note was in rate base, PGE responded that "This account is in rates according to OPUC Order No. 02-280 dated 4/19/2002)."

In their February 11, 2009 response to BPA's Issue List PGE said that "BPA should adopt a common functionalization for similar types of regulatory assets and liabilities. No additional information on this item was submitted by PGE.

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).

The documentation submitted by PGE in response to BPA's Data Requests and Issue List did not show that the Portland Energy Solutions Note was included in PGE's rate base by the Oregon PUC. PGE's response to BPA's data request only stated that **"**This account is in rates according to OPUC Order No. 02-280 dated 4/19/2002)."

Decision:

Because PGE did not provide documentation showing that the Portland Energy Solutions Note was included in PGE's retail rate base, BPA will functionalize Surplus CAA Allowances to distribution.

Table 4.3.7: Account 254 Other Regulatory Liabilities: Portland Energy Solutions Note ($)

	Total	Production	Transmission	Dist/Other
As-Filed	173,115	173,115	0	0
BPA Adjusted	173,115	0	0	173,115

4.3.8. Account 254 Other Regulatory Liabilities: FERC Settlement – FERC Docket No. EL02-114 dated 11/10/2003

Statement of Issue:

Has PGE properly calculated and appropriately functionalized its Other Regulatory Liabilities: FERC Settlement – FERC Docket No. EL02-114 dated 11/10/2003 (FERC Settlement), in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does PGE's documentation submitted with its ASC filing constitute a valid Direct Analysis? Should FERC Settlement be functionalized to Production?

Statement of Facts:

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

In its Oct 1, 2008 ASC Filing, PGE functionalized FERC Settlement in Account 254 to Production. No detail describing the costs was provided, so BPA was unable to determine if Production was appropriate for this item.

Summary of Parties' Positions:

In PGE's December 1, 2008 response to BPA's data request BPA-PG-010 PGE stated "This account consists of FERC settlement funds related to power supply transactions. The FERC settlement was power supply related and is functionalized as production."

In response to BPA's question on whether the FERC Settlement was in rate base, PGE responded that "The settlement is described in FERC Docket No. EL02-114 dated 11/10/2003 which the OPUC passed through to customers."

In their February 11, 2009 response to BPA's Issue List PGE said that "BPA should adopt a common functionalization for similar types of regulatory assets and liabilities. No additional information on this item was submitted by PGE.

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).

The documentation submitted by PGE in response to BPA's Data Requests and Issue List did not show that the FERC Settlement was included in PGE's rate base by the Oregon PUC. PGE's response to BPA's data request only stated that "The settlement is described in FERC Docket No. EL02-114 dated 11/10/2003 which the OPUC passed through to customers.**"**

Decision:

Because PGE did not provide documentation showing that the FERC Settlement was included in PGE's retail rate base, BPA will functionalize the FERC Settlement to distribution.

Table 4.3.8: Account 254 Other Regulatory Liabilities: FERC Settlement ($)

	Total	Production	Transmission	Dist/Other
As-Filed	-15,416	-15,416	0	0
BPA Adjusted	-15,416	0	0	-15,416

4.3.9. Account 254 Other Regulatory Liabilities: Williams Settlement

Statement of Issue:

Has PGE properly calculated and appropriately functionalized its Other Regulatory Liabilities: Williams Settlement, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does PGE's documentation submitted with its ASC filing constitute a valid Direct Analysis? Should the Williams Settlement be functionalized to Production?

Statement of Facts:

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

In its Oct 1, 2008 ASC Filing, PGE functionalized Williams Settlement in Account 254 to Production. No detail describing the costs was provided, so BPA was unable to determine if Production was appropriate for this item.

Summary of Parties' Positions:

In PGE's December 1, 2008 response to BPA's data request BPA-PG-010 PGE stated "This settlement recovered overcharges from the Williams Pipeline Co. for gas deliveries. PGE's use of gas is for generation therefore this account is functionalized as production."

In response to BPA's question on whether the Williams Settlement was in rate base, PGE responded that "This adjustment was in rates according to OPUC Order No. 04-293 dated 5/24/2004."

In their February 11, 2009 response to BPA's Issue List PGE said that "BPA should adopt a common functionalization for similar types of regulatory assets and liabilities. No additional information on this item was submitted by PGE.

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).

The documentation submitted by PGE in response to BPA's Data Requests and Issue List did not show that the Williams Settlement was included in PGE's rate base by the Oregon PUC. PGE's response to BPA's data request only stated that "This adjustment was in rates according to OPUC Order No. 04-293 dated 5/24/2004."

<u>Decision</u>:

Because PGE did not provide documentation showing that the Williams Settlement was included in PGE's retail rate base, BPA will functionalize the Williams Settlement to distribution.

Table 4.3.9: Account 254 Other Regulatory Liabilities: Williams Settlement ($)

	Total	Production	Transmission	Dist/Other
As-Filed	32,036	32,036	0	0
BPA Adjusted	32,036	0	0	32,036

4.3.10. Account 254 Other Regulatory Liabilities: Power Cost Adjustment

<u>Statement of Issue</u>:

Has PGE properly calculated and appropriately functionalized its Other Regulatory Liabilities: Power Cost Adjustment, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does PGE's documentation submitted with its ASC filing constitute a valid Direct Analysis? Should the Power Cost Adjustment be functionalized to Production?

<u>Statement of Facts</u>:

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

In its Oct 1, 2008 ASC Filing, PGE functionalized the Power Cost Adjustment in Account 254 to Production. No detail describing the costs was provided, so BPA was unable to determine if Production was appropriate for this item.

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

In PGE's December 1, 2008 response to BPA's data request BPA-PG-010 PGE stated "The power cost adjustment is related to power costs in the 2001 – 2002 time period. Power costs are generation related and are functionalized as production."

In response to BPA's question on whether the Power Cost Adjustment was in rate base, PGE responded that "This adjustment was in rates according to OPUC Order No. 04-293 dated 5/24/2004."

In their February 11, 2009 response to BPA's Issue List PGE said that "BPA should adopt a common functionalization for similar types of regulatory assets and liabilities. No additional information on this item was submitted by PGE.

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).

The documentation submitted by PGE in response to BPA's Data Requests and Issue List did not show that the Power Cost Adjustment was included in PGE's rate base by the Oregon PUC. PGE's response to BPA's data request only stated that "This adjustment was in rates according to OPUC Order No. 04-293 dated 5/24/2004."

Decision:

Because PGE did not provide documentation showing that the Power Cost Adjustment was included in PGE's retail rate base, BPA will functionalize Power Cost Adjustment to distribution.

Table 4.3.10: Account 254 Other Regulatory Liabilities: Power Cost Adjustment ($)

	Total	Production	Transmission	Dist/Other
As-Filed	1,494,606	1,494,606	0	0
BPA Adjusted	1,494,606	0	0	1,494,606

4.3.11. Account 254 Other Regulatory Liabilities: Coyote Springs Major Maintenance Deferral

Statement of Issue:

Has PGE properly calculated and appropriately functionalized its Other Regulatory Liabilities: Coyote Springs Major Maintenance Deferral, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does PGE's documentation submitted with its ASC filing constitute a valid Direct Analysis? Should the Coyote Springs Major Maintenance Deferral be functionalized to Production?

<u>Statement of Facts</u>:

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

In its Oct 1, 2008 ASC Filing, PGE functionalized the Coyote Springs Major Maintenance Deferral in Account 254 to Production. No detail describing the costs was provided, so BPA was unable to determine if Production was appropriate for this item.

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

In PGE's December 1, 2008 response to BPA's data request BPA-PG-010 PGE stated "This is a deferral of maintenance expenses at the Coyote Springs gas generation plant near Boardman in eastern Oregon. Coyote Springs is a generation plant and the costs are functionalized as production."

In response to BPA's question on whether the Coyote Springs Major Maintenance Deferral was in rate base, PGE responded that "This adjustment was in rates according to OPUC Order No. 04-293 dated 5/24/2004."

In their February 11, 2009 response to BPA's Issue List PGE said that "BPA should adopt a common functionalization for similar types of regulatory assets and liabilities. No additional information on this item was submitted by PGE.

<u>Analysis of Positions:</u>

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).

The documentation submitted by PGE in response to BPA's Data Requests and Issue List did not show that the Coyote Springs Major Maintenance Deferral was included in PGE's rate base by the Oregon PUC. PGE's response to BPA's data request only stated that "This adjustment was in rates according to OPUC Order No. 04-293 dated 5/24/2004."

<u>Decision</u>:

Because PGE did not provide documentation showing that the Coyote Springs Major Maintenance Deferral was included in PGE's retail rate base, BPA will functionalize Power Cost Adjustment to distribution.

**Table 4.3.11: Account 254 Other Regulatory Liabilities:
Coyote Springs Major Maintenance Deferral ($)**

	Total	Production	Transmission	Dist/Other
As-Filed	5,697,232	5,697,232	0	0
BPA Adjusted	5,697,232	0	0	5,697,232

4.3.12. Account 254 Other Regulatory Liabilities: Energy Efficiency Programs Residual

Statement of Issue:

Has PGE properly calculated and appropriately functionalized its Other Regulatory Liabilities: Energy Efficiency Programs Residual, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does PGE's documentation submitted with its ASC filing constitute a valid Direct Analysis? Should the Energy Efficiency Programs Residual be functionalized to Production?

Statement of Facts:

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

In its Oct 1, 2008 ASC Filing, PGE functionalized the Energy Efficiency Programs Residual in Account 254 to Production. No detail describing the costs was provided, so BPA was unable to determine if Production was appropriate for this item.

Summary of Parties' Positions:

In PGE's December 1, 2008 response to BPA's data request BPA-PG-010 PGE stated "Consists of residual expenses for energy efficiency programs. Energy efficiency programs save kWh which does not need to be generated, therefore this account is functionalized as production."

In response to BPA's question on whether the Coyote Springs Major Maintenance Deferral was in rate base, PGE responded that "The OPUC authorized this according to Advice No. 05-19 dated 12/20/2005."

In their February 11, 2009 response to BPA's Issue List PGE said that "BPA should adopt a common functionalization for similar types of regulatory assets and liabilities. No additional information on this item was submitted by PGE.

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).

The documentation submitted by PGE in response to BPA's Data Requests and Issue List did not show that the Energy Efficiency Programs Residual was included in PGE's rate base by the Oregon PUC. PGE's response to BPA's data request only stated that ""The OPUC authorized this according to Advice No. 05-19 dated 12/20/2005."

Decision:

Because PGE did not provide documentation showing that the Energy Efficiency Programs Residual was included in PGE's retail rate base, BPA will functionalize Energy Efficiency Programs Residual to distribution.

Table 4.3.12: Account 254 Other Regulatory Liabilities: Energy Efficiency Programs Residual ($)

	Total	Production	Transmission	Dist/Other
As-Filed	208,210	208,210	0	0
BPA Adjusted	208,210	0	0	208,210

4.3.13. Account 254 Other Regulatory Liabilities: Zero Interest Program Loan Repayments

Statement of Issue:

Has PGE properly calculated and appropriately functionalized its Other Regulatory Liabilities: Zero Interest Program Loan Repayments, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does PGE's documentation submitted with its ASC filing constitute a valid Direct Analysis? Should the Zero Interest Program Loan Repayments be functionalized to Production?

Statement of Facts:

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

In its Oct 1, 2008 ASC Filing, PGE functionalized the Zero Interest Program Loan Repayments in Account 254 to Production. No detail describing the costs was provided, so BPA was unable to determine if Production was appropriate for this item.

Summary of Parties' Positions:

In PGE's December 1, 2008 response to BPA's data request BPA-PG-010 PGE stated "The zero interest loan repayments are BPA provided payments to customers for home weatherization.

Weatherization saves kWh that would otherwise be generated, therefore this account is functionalized as production."

In response to BPA's question on whether the Zero Interest Program Loan Repayments were in rate base, PGE responded that "The OPUC authorized this according to Advice No. 05-19 dated 12/20/2005."

In their February 11, 2009 response to BPA's Issue List PGE said that "BPA should adopt a common functionalization for similar types of regulatory assets and liabilities. No additional information on this item was submitted by PGE.

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).

The documentation submitted by PGE in response to BPA's Data Requests and Issue List did not show that the Zero Interest Program Loan Repayments were included in PGE's rate base by the Oregon PUC. PGE's response to BPA's data request only stated that "The OPUC authorized this according to Advice No. 05-19 dated 12/20/2005."

Decision:

Because PGE did not provide documentation showing that the Zero Interest Program Loan Repayments were included in PGE's retail rate base, BPA will functionalize Zero Interest Program Loan Repayments to distribution.

Table 4.3.13: Account 254 Other Regulatory Liabilities: Zero Interest Program Loan Repayments ($)

	Total	Production	Transmission	Dist/Other
As-Filed	241,390	241,390	0	0
BPA Adjusted	241,390	0	0	241,390

4.4. Schedule 1A: Cash Working Capital

No direct adjustment.

4.5. <u>Schedule 2: Capital Structure and Rate of Return</u>

No direct adjustment.

4.6. <u>Schedule 3: Expenses</u>

No direct adjustment.

4.7. <u>Schedule 3A: Taxes</u>

No direct adjustment.

4.8. <u>Schedule 3B: Other Included Items</u>

No direct adjustment.

4.9. <u>Account 421 - Miscellaneous Non-operating Income</u>

<u>Statement of Issue</u>:

Did PGE properly calculate and appropriately functionalize Account 421 - Miscellaneous Non-operating Income, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? BPA's January 28, 2009, Issue List, Item 7?

<u>Statement of Facts</u>:

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

PGE’s Appendix 1 template contained an error for this account. PGE’s Appendix 1 template incorrectly listed the default functionalization for Account 421 as production, when it should have been production. PGE functionalized these costs to production and did not perform a Direct Analysis.

<u>Summary of Parties’ Positions:</u>

In their February 11, 2009 response to BPA’s Issue List PGE said that it “intends to perform a direct analysis on this account.”

Analysis of Position:

The description of Account 421 in the FERC Uniform System of Accounts states that

> This account shall include all revenue and expense items, except taxes properly includible in the income account, not provided for elsewhere. Related taxes shall be recorded in Account 408, Taxes Other Than Income Taxes, or Account 409.2, Income Taxes, Other Income and Deductions, as appropriate.
>
> *Items*
>
> 1. Profit on sale of timber. (See §1767.16 (g)(3).)
> 2. Profits from operations of others realized by the utility under contracts.
> 3. Gains on disposition of investments. Also, gains on reacquisition and resale or retirement of the utility's debt securities when the gain is not amortized or used by a jurisdictional regulatory agency to reduce embedded debt cost in establishing rates. (See §1767.15 (q).)
> 4. This account shall include the accretion expense on the liability for an asset retirement obligation included in Account 230, Asset Retirement Obligations, related to nonutility plant.
> 5. This account shall include the depreciation expense for asset retirement costs related to nonutility plant.
> 6. The utility shall record in this account gains resulting from the settlement of asset retirement obligations related to nonutility plant in accordance with the accounting prescribed in §1767.15(y).

On March 10, 2009, PGE submitted a Direct Analysis of this Account showing that revenues in this Account were related to either non-utility operations or to the distribution function of the company.

Decision:

BPA accepts PGE's direct analysis and will functionalize this account to distribution.

Table 4.8.1: Account 421 Miscellaneous Non-operating Income: ($)

	Total	Production	Transmission	Dist/Other
As-Filed	6,202,968	6,202,968	0	0
BPA Adjusted	6,202,968	0	0	6,202,968

4.9.1. Account 456 - Other Electric Revenues

Statement of Issue:

Did PGE properly calculate and appropriately functionalize Account 456 – Other Electric Revenues, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology?

Statement of Facts:

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

PGE's Appendix 1 template contained an error for this account. PGE's Appendix 1 template incorrectly listed the default functionalization for Account 421 as production, when it should have been production. PGE functionalized these costs to production and did not perform a Direct Analysis.

PGE's Response:

In their February 11, 2009 response to BPA's Issue List PGE said that it "intends to perform a direct analysis on this account."

Analysis of Positions:

The description of Account 456 in the FERC Uniform System of Accounts states that

> This account shall include revenues derived from electric operations not includible in any of the foregoing accounts. It shall also include, in a separate subaccount, revenues received from operation of fish and wildlife and recreation facilities whether operated by the company or by contract concessionaires, such as revenues from leases or rentals of land for cottages, homes, or campsites.
>
> *Items*
>
> 1. Commission on sale or distribution of electricity of others when sold under rates filed by such others.
> 2. Compensation for minor or incidental services provided for others such as customer billing, and engineering.
> 3. Profit or loss on the sale of material and supplies not ordinarily purchased for resale and not handled through merchandising and jobbing accounts.
> 4. Sale of steam, but not including sales made by a steam heating department or transfers of steam under joint facility operations.
> 5. Include in a separate subaccount, revenues in payment for rights and/or benefits received from others which are realized through research, development, and demonstration ventures. In the event the amounts received are so large as to distort revenues for the year in which received (5 percent of net income before application of the benefit), the amounts shall be credited to Account 253, Other Deferred Credits, and amortized by credits to this account over a period not to exceed 5 years.

On March 10, 2009, PGE submitted a Direct Analysis of this Account showing that revenues in this Account were related to either non-utility operations or to the distribution function of the company.

Decision:

BPA accepts PGE's Direct Analysis of Account 456.

Table 4.8.2: Account 456 Other Electric Revenues: ($)

	Total	Production	Transmission	Dist/Other
As-Filed	42,553,031	42,553,031	0	0
BPA Adjusted	42,553,031	187,541	4,791,499	37,573,992

4.10. SCHEDULE 4: Average System Cost

No Direct Adjustments.

5. SUPPORTING DOCUMENTATION:

5.1. Purchased Power and Sales for Resale

No direct adjustment.

5.2. Salaries and Wages

No direct adjustment.

5.3. Labor Ratios

No direct adjustment.

5.4. Distribution Loss Factor

5.4.1. Distribution Losses

Statement of Issue:

Did PGE include the correct Distribution Loss Factor in their Appendix 1 Filing?

Statement of Facts:

During BPA's review of PGE's ASC Filing, BPA noticed that PGE incorrectly deducted BPA's transmission loss factor in determination of their distribution loss factor. PGE's distribution loss factor came from a distribution loss study that was reviewed and approved by BPA.

Endnote e of the 2008 ASCM states:

> *Method 3, Default:* If a Utility does not have a current loss study or grade meters, BPA will accept the following method for determining a Utility's distribution loss factor.
>
> i. Calculate a 5-year average total system loss factor, using data from the Base Period plus the preceding 4 years. IOUs will use data from the FERC Form 1. COUs will use a comparable data source.
> ii. From this 5-year total system loss factor, subtract the loss factor for BPA's transmission system.
> iii. The resulting loss factor will be deemed to be the exchanging Utility's distribution loss factor for calculating Contract System Load and exchange loads under the REP.

PGE did not need to deduct BPA's transmission loss factor from its distribution loss factor because its distribution loss factor was from a BPA approved distribution loss study.

In addition, PGE used a different distribution loss factor on Schedule 4 than supplied in its distribution loss study. The loss factor submitted by PGE in their Appendix 1, *Distribution Loss Calc* tab was 5.4%. However, the distribution loss factor included on Schedule 4 was not linked to *Distribution Loss Calc* tab. The distribution losses included on Schedule 4 were equivalent to a 4.7% distribution loss factor.

Decision:

BPA will correct the distribution loss error on Schedule 4. PGE's distribution losses increased from 868,172 MWH to 995,294 MWH.

Table 5.4.1: Distribution Losses (MWH)

As-Filed	868,172
BPA Adjusted	995,294

5.5. <u>ASC FORECAST MODEL:</u>

5.5.1. ASC Forecast Model: New Resources – Port Westward Projected Capital and Operating Costs and Capacity Factor for 2007.

Statement of Issue

What are correct projected annual costs for the Port Westward combined cycle combustion turbine, scheduled to begin operation in June of 2007.

Statement of Facts:

During review of PGE's ASC filing, BPA noticed that the projected 2007 cost ($/MMBtu) of natural gas for Port Westward was different in various parts of the ASC Forecast model. Upon closer examination, BPA noticed that several other Port Westward items in the *New Resources* Tab of the ASC Forecast Model appeared inconsistent.

Analysis of Positions:

BPA staff contacted PGE about the discrepancies in the 2007 Port Westward costs. PGE staff resubmitted revised cost data for the Port Westward plant.

Decision:

BPA will accept the revised projected 2007 Port Westward cost data. The table below shows the As-Filed and As-Revised cost and operating data for Port Westward for a full year of operation.

Table 5.6.1: ASC Forecast Model – 2007 Port Westward Data

ITEM	As- Filed	As-Amended
Other Production	$250,408,852	$267,015,214
Plant Materials and Operating Supplies	$89,568	$2,911,325
Other Power – Fuel	$90,340,172	$124,223,121
Depreciation	$4,582,000	$8,668,704
Expected Annual Generation (MWH)	2,033,378	2,367,744
Production Property Taxes	$2,437,809	$2,602,958

6. OTHER ISSUES

6.1. <u>Generic Issue List</u>

In addition to the above issues specific to Portland General Electric, BPA raised seven issues that may be "generic" to all utilities. Following are the issues, as discussed with the utilities 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 IOU's 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

<u>Statement of Issue:</u>

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

<u>Statement of Facts:</u>

During review of the ASC filings, BPA noticed that Direct Analysis performed by the Utilities resulted in different Functionalization for similar types of software. For example, metering and customer information system (CIS) software were functionalized to Distribution by PGE while PacifiCorp, Puget and NorthWestern functionalized such software using the PTD ratio.

In addition, two utilities, Avista and Idaho, did not perform a direct analysis on software costs included in Account 303 and functionalized all software costs to distribution. The 2008 ASCM specifies that the default functionalization for Account 303 – Intangible Plant - Miscellaneous is Direct, with an option to DIST.

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

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, some 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:

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"[6] or "supports all areas of the company."[7] 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

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

[7] 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.

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) 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.

<u>Decision:</u>

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 and includes the functionalization BPA will use to functionalize such software categories.

<u>System Categories</u>

- ***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 which manage the residential and small commercial customer information, bill calculation and presentation, and payment processes. Distribution - Accounts 901-910
    - *Industrial Billing* – systems which manage the large industrial customers, bill calculation and presentation processes. Distribution - Accounts 901-910
    - *Energy and Demand Management Systems* – systems and software which design, administer, manage, track, and report on the utility's portfolio of Demand-Side Management (DSM) and Energy Efficiency (EE) programs. Production - Accounts 500-557

- *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 which manage information about the customers of the utility.   Distribution - Accounts 901-910
- *Advanced Meter Infrastructure (AIM) System* – systems which measure, collect and analyze energy usage from advanced devices through various communication media on request or on a pre-defined schedule. It would also include 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 which 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 application as employee benefits, human resources, training, time entry, payroll, and compensation management systems.

- *Payroll System* – systems which calculate pay for employees and produces payments (checks or direct deposits). LABOR – Account 920
- *Human Resources* – systems which maintain employee information required to pay employees and maintain individual employee personal and work-related information. LABOR – Account 920
- *Training System* – systems which maintain information about all employee training requirements, schedules, certifications, courses, and update/recertification requirements. LABOR – Account 920
- *Time Entry System* – systems which capture actual time and attendance information for employees. LABOR – Account 920
- *Compensation Management System* – systems which 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 application 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 which 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 which 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 application 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 which 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 which 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 which manage the debt owned by the utility including debt instruments, notes, bonds, commercial paper, and stocks. PTDG – Various Accounts
- *Budget Preparation* – systems which(s) provides 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 which automate the continuing property records of the utility. PTDG – Various Accounts
- *Work Order Accounting* – systems which 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 – Various Accounts
- *Cost Accounting* – systems which provide a standard cost accounting capability for both capital projects and operations and maintenance activities. LABOR – Account 920

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

- *Executive Information* – systems which 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 which capture both internal and external information related to key business indicators for senior management. LABOR – Account 920
- *Business Intelligence* – systems which provide historical, current, and predictive information about the operations of the utility. LABOR – Account 920

➢ ***Market Operations and Trading*** – this category includes such application 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 - Accounts 560-573
- *Transmission Rights and Access* – systems which maintain data on the utility's transmission line rights and access policies. Transmission - Accounts 560-573
- *Transmission Pricing and Billing* – systems which, similar to the *Customer Information System* above, maintain information on transmission system customers, bill calculation and presentation, and payment processes. Transmission - Accounts 560-573
- *Wholesale Billing and Settlement* – systems which, 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 which 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 - Accounts 500-557

➢ ***Planning Models*** – this category includes such application 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 application as materials management, purchasing, warehouse management, inventory, fleet management, fuel management, and alternative energy supply systems.

- *Materials Management* – systems which 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 - Various Accounts
- *Purchasing* – systems which 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 which 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 which 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 which maintain information on fuel management for the utility's fleet operations. Distribution - Account 933

- *Alternative Energy Supply* – systems which manage the availability of energy supply from alternative sources which may be outside the control of the utility.
  Production - Accounts 500-557

➢ ***System Operations*** – this category includes such application 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 which 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 - Accounts 500-557
- *Generation Operations and Management* – systems used to maximize plant operating income by optimizing output and heat rates and by reducing maintenance expenses. Production - Accounts 500-557
- *Substation Operations and Management* – systems used to monitor the operation of substations to maximize performance and ensure safe equipment operations. TD - Accounts 560-573 & 580-599
- *Supervisory Control And Data Acquisition (SCADA)* – systems which 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 - Accounts 560-573 & 580-599
- *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 - Accounts 560-573 & 580-599
- *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 - Accounts 500-557

➢ ***Work Management*** – this category includes such application 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- Accounts 500-557
- *Work Order* – systems which manage longer-duration work, either capital or operations and maintenance frequently performed by multi-person crews.
  Distribution - Accounts 580-599
- *Service Order* – systems which manage the short-interval work of the utility typically performed by service crews. The system would include work scheduling, tracking, and order completion. Distribution - Accounts 580-599
- *Outage Management* – systems which 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; calculates estimates of restoration times; provides information on crews needed and assisting in restoration; and predicts the location of fuse or breaker that opened upon failure. Representative

vendor solutions include: ABB, GE Energy, Intergraph, Oracle Utilities, and Trimble. Distribution Accounts - 580-599

6.1.2. Schedule 1: Plant Investment/Rate Base: Account 182.3, Other Regulatory Assets; Account 254, Other Regulatory Liabilities

Statement of Issue:

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

Statement of Facts:

There is inconsistency in the way the IOUs functionalize Deferred Pension, Pay and other labor related Assets and Liabilities. PGE and NW use the Labor Ratio. IPC uses PTD. PSE and PAC 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 amongst 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." [8] 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.[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 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 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.

Decision:

Following the Review Processes and publication of the Final ASC Reports for FY 2009, BPA will work with the parties to develop a standard functionalization protocol for common types of regulatory assets and liabilities.

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

For the FY 2009 ASC Filings, BPA will use consistent decision criteria for common types of Regulatory Assets and Liabilities.

6.1.3. Schedule 1: Plant Investment/Rate Base: 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 Party's Position

Avista, IPC, NorthWestern, PacifiCorp and PGEs February 25, 2009, joint response to BPA's Issue Lists stated that

> The IOUs agreed 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 contend that asset accounts that have a corresponding liability account be functionalized consistently.

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. Schedule 1: Plant Investment/Rate Base: 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 when not included in rate base. Many of 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, NW, PSE and Avista functionalized several items in these accounts, also not included in its retail 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."[11] 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.[12]

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

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

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.[13]

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 are eventually moved from the balance sheet to the income statement through recognition of the revenue or expense. They are only 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 rate base for ASC purposes. BPA will not change the functionalization rules of an income statement account as the result of a direct analysis on a regulatory asset or liability.

6.1.5. Schedule 3: Expenses: 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?

Statement of Facts:

PacifiCorp reduced the amount of its purchased power expense and sales for resale revenue by book-outs and trading adjustments. Other utilities did not.

The inclusion 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

[13] Ibid.

> 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 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 bookouts and trading adjustments.

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

Statement of Issue:

Whether BPA should 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 after the Base Period. None of those utilities submitted documentation or copies of firm natural gas supply contracts to support their projected natural gas prices.

Summary of Parties' Positions:

Avista, IPC, NorthWestern, PacifiCorp and PGE'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 OPUC's 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

> That 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.

<u>Analysis of Positions:</u>

All of the respondents 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 also supported the principle that the prices should reflect basis or hub differences as adjustments to the commodity price.

It was also suggested that the price should reflect adjustments for firm gas transportation costs on a utility-by-utility, resource-specific basis.

The parties contended that the use of a third party gas price forecast to achieve consistency between the exchanging utility's natural gas forecasts should not preclude a utility from using its own forecast.

BPA agrees with the parties that a common gas forecast would be one reasonable approach. However, using the utility-supplied natural gas forecasts from the utilities' October 1, 2009, ASC filings is a better option for FY 2009. Such forecasts would more closely match projected gas prices that were used to set the PF Exchange Rate in BPA's 2007 Supplemental Rate Proceeding than would using a more recent forecast. In addition, BPA has been paying REP benefits based on ASCs containing these natural gas price forecasts. Switching to a new forecast at this time could result in large true-ups when the final ASCs are determined. This approach is also reasonable on a one-time basis because it is based on the utilities' own forecasts, which the utilities presumed to be reasonable when filed. This approach for FY 2009, however, does not constitute a precedent for future ASC determinations.

<u>Decision:</u>

BPA will accept the utilities' as-filed projected natural gas prices used for new resources for FY 2009 ASC filings.

6.1.7. ASC Forecast Model: New Plant Additions – Capacity Factor

<u>Statement of Issue:</u>

Should BPA use common representative capacity factors in the ASC Forecast model for estimating the operating costs and expected energy output for new plant additions?

<u>Statement of Facts:</u>

Projected capacity factors vary significantly between utilities for similar types of new resources.

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, Idaho Power, NorthWestern, PacifiCorp & 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, it is understood that if a utility chooses to use capacity factor outside the above range for a given new resource that utility will have to supply complete justification for such capacity factor."

Analysis of Positions:

After a discussion with the parties, BPA will defer a decision on this issue until after the FY 2009 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 2009 ASCs.

Draft Decision:

The capacity factors submitted by each utility will be accepted for this FY 2009 Review Process. BPA, however, makes no precedential decision at this time. The issue will be revisited in future ASC filings.

7. FY 2009 ASC

Overall BPA adjustments, including all changes made to PGE's Appendix 1 filing, increase PGE's CY 2006 ASC by $ 1.81/MWh and increase PGE's FY 2009 ASC by $2.79/MWh. PGE's ASC for FY 2009, prior to the addition of any new resources is $60.22/MWh.

8. REVIEW SUMMARY

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

The as-filed Appendix 1 Filing, including the ASC Forecast Model and supporting documentation used to calculate PGE'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 PGE'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 PGE's ASC.