FY 2009 AVERAGE SYSTEM COST DRAFT REPORT

FOR

NorthWestern Energy

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

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

April 13, 2009

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TABLE OF CONTENTS

List of Tables

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1. FILING DATA

Utility: **NorthWestern Energy**
40 E. Broadway
Butte, MT 59701
http://www.northwesternenergy.com/

Parties to the Filing:

Investor Owned Utilities (IOUs):
- Avista Utilities (Avista)
- Idaho Power Company (IPC)
- Portland General Electric (PGE)
- 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 NWE's ASC for 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 wished to preserve any issue regarding BPA 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 NWE 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 As Filed	April 13, 2009 Draft Report
Production Cost	$283,058,155	$286,947,701
Transmission Cost	33,819,170	16,463,470
(Less) NLSL Costs		
Contract System Cost	**$316,877,325**	**$303,411,171**
Total Retail Load (MWh)	5,749,741	5,749,741
(Less) NLSL		
Total Retail Load (Net of NLSL)	5,749,741	5,749,741
Distribution Losses	252,989	252,989
Contract System Load	**6,002,730**	**6,002,730**
CY 2006 Base Period ASC ($/MWh)	**52.79**	**50.55**

2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 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	**N/A**	**N/A**	**N/A**	**N/A**
Expected On-Line Date				
Delta*				

Draft Report FY 2009 Exchange Period ASC				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On-Line Date				
Delta*				

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

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

As-Filed FY 2009 Exchange Period ASC				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On-Line Date				
Delta*				

Draft Report FY 2009 Exchange Period ASC				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On-Line Date				
Delta*				

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

2.3. FY 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 2.3: Exchange Period FY 2009 ASC ($/MWh)
Prior to New Resource Additions

Date	October 1, 2008 As-Filed	April 13, 2009 Draft Report
FY 2009	**52.79**	**52.99**

The as-filed Appendix 1 Filing, including the ASC Forecast Model, supporting documentation, and resource cost determination for the NLSL assessment used to calculate NWE's ASC can be viewed at BPA's Residential Exchange Program (REP) website:
http://www.bpa.gov/corporate/finance/ascm/filings.cfm

3. FILING REQUIREMENTS

3.1. Introduction

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839c(c), established the REP. Any Pacific Northwest utility interested in participating in the REP may offer to sell power to BPA at the average system cost 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 1, 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. ASC Forecast

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 (2006) to the end of the Exchange Period (CY 2006).

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.

NWE responded to BPA's December 1, 2008, data request in part on January 9, 2009, submitting additional responses on January 30, 2009, February 2, 2009, and February 6, 2009, and completing the response to BPA's data request on February 10, 2009. Section III of the 2008 ASCM, BPA REVIEW PROCESS, prescribes the discovery procedures during the review of an ASC filing:

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

Because this is the first ASC Review under the 2008 ASCM, BPA understands that many of the utility analysts preparing the ASC filings are new to the process. Consequently, BPA allowed utilities extra time, when requested, to complete discovery requests. BPA encourages NWE to be more responsive in future ASC Reviews and to ensure that discovery requests are provided in a more timely fashion.

4.1. Identification and Analysis of Issues from BPA Issue List

BPA raised the following issues during the ASC Review Process, and NWE submitted its responses. No other party raised issues or commented on NWE'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 in BPA's February 3, 2009, Issue List to NWE were resolved during the review of NWE's ASC filing.

1. Entire Filing – Detailed Allocation of FERC Form 1 Costs to Montana Jurisdiction
2. Entire Filing – Responses to Data Requests

4.3. SCHEDULE 1: Plant Investment/Rate Base:

4.3.1. Account 182.3 Other Regulatory Assets: Unbilled CTC QF

Statement of Issue:

Has NWE properly calculated and appropriately functionalized its Unbilled CTC QF in accordance with the requirements of the functionalization rules of the 2008 ASCM? Does NWE's documentation submitted with its ASC filing constitute a valid direct analysis? Should the costs associated with Unbilled CTC QF 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 October 1, 2008, ASC Filing, NWE functionalized Unbilled CTC QF in Account 182.3 to Production.

Summary of Parties' Positions:

NWE contends that Unbilled CTC QF in Account 182.3 should be functionalized to Production.

Analysis of Positions:

NWE's January 30, 2009, response to BPA's December 1, 2008, data request No.8 stated:

> Unbilled CTC QF: Out of market QF costs recovered from customers.

In NWE's January 30, 2009, response to BPA's December 1, 2008, data request No.14, NWE stated:

> Unbilled CTC QF: relates to supply costs, directly assigned to Production.

In response to Data Request BPA-NW-14, asking if the Unbilled CTC QF was included in NWE's jurisdictional rate base, NWE replied:

> The final result of NWE's filing is a stipulation in which the Account 182.3 amounts are included as filed.

However, the next document following the above statement indicated that Unbilled CTC QF was not in NWE's jurisdictional rate base.

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).

NWE's documentation and support did not show that NWE received a return on the Unbilled CTC QF costs.

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 and 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]

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.

Draft Decision:

Because NWE did not provide documentation showing that the Unbilled CTC QF was included in NWE's retail rate base, BPA will functionalize the Unbilled CTC QF to Distribution.

Table 4.3.1: Account 182.3 Other Regulatory Assets: Unbilled CTC QF ($)

	Total	Production	Transmission	Dist/Other
As-Filed	(1,548)	(1,548)	0	0
BPA Adjusted	(1,548)	0	0	(1,548)

[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.

4.3.2. Account 182.3 Other Regulatory Assets: Basin Creek

Statement of Issue:

Has NWE properly calculated and appropriately functionalized Basin Creek in accordance with the requirements of the functionalization rules of the 2008 ASCM? Does NWE's documentation submitted with its ASC filing constitute a valid direct analysis? Should the costs associated with Basin Creek be functionalized to Production?

Statement of Facts:

NWE's January 30, 2009, response to BPA's December 1, 2008, Data Request No.8 stated:

> Basin Creek: Electric Energy supply costs provided from the Basin Creek generating facility.

In NWE's January 30, 2009, response to BPA's December 1, 2008, Data Request No.14, NWE stated:

> Unbilled CTC QF: relates to supply costs, directly assigned to Production.

In response to Data Request BPA-NW-14, asking if the Unbilled CTC QF was included in NWE's jurisdictional rate base, NWE replied:

> The final result of NWE's filing is a stipulation in which the Account 182.3 amounts are included as filed.

However, the next document following the above statement indicated that Basin Creek is not in NWE's jurisdictional rate base. The "Comments' column on the table stated:

> Since we are able to recover all prudently incurred energy supply costs, and because the Basin Creek costs are included in the electric supply tracker, this does not impact the IS, rather it is an inc (dec) to a regulatory asset.

Summary of Parties' Positions:

In its October 1, 2008, ASC Filing, NWE functionalized Basin Creek in Account 182.3.to Production.

Analysis of Positions:

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

The 2008 ASCM 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).

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.

The documentation submitted by NWE did not show that Basin Creek costs are included in NWE's rate base by the Montana PSC.

Draft Decision:

Because NWE did not provide documentation showing that Basin Creek was included in NWE's retail rate base, BPA will functionalize Basin Creek to Distribution.

Table 4.3.2: Account 182.2 Other Regulatory Assets:
Basin Creek ($)

	Total	Production	Transmission	Dist/Other
As-Filed	553,590	553,590	0	0
BPA Adjusted	553,590	0	0	553,590

4.3.3. Account 182.3 Other Regulatory Assets - Compensated Absences - Contra

Statement of Issue:

Has NWE properly calculated and appropriately functionalized its Other Regulatory Assets: Compensated Absences - Contra, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does NWE's documentation submitted with its ASC filing constitute a valid direct analysis? Should the costs associated with Compensated Absences - Contra be functionalized using the Labor Ratio?

Statement of Facts:

NWE's January 30, 2009, response to BPA's December 1, 2008, Data Request No.8 stated:

> The following line items are related to employee benefits recorded on the books as total amounts (common) and require an allocation between electric and natural gas (see response to BPA-NW-10 for the common allocation factor):
>
> - Compensated Absences/Contra & Compensated Absences
> - FAS 106 & FAS 112
> - Net Regulatory Asset - Pension Plan

In NWE's January 30, 2009, response to BPA's December 1, 2008, Data Request No.14, NWE stated:

- Compensated Absences: Relates to vacation accruals and employee benefits that encompass all functions, should be allocated based on labor.
- FAS 1061FAS 112lPension: Relates to employee benefits that encompass all functions, should be allocated based on labor.

In response to Data Request BPA-NW-14, asking if the Compensated Absences – Contra was included in NWE's jurisdictional rate base, NWE replied:

> The final result of NWE's filing is a stipulation in which the Account 182.3 amounts are included as filed.

However, the next document following the above statement indicated that Compensated Absences - Contra are not in NWE's jurisdictional rate base. The "Comments' column on the table stated:

> Consistent with historical regulatory treatment, the cost of service used to establish rates has historically included vacation on a cash basis. Represents difference between cash and accrual.

On the same document, under the column entitled "Rate Base" where other items were listed as "yes" or "no", NWE stated that the Compensated Absences – Contra were "Offset by benefit liability."

Summary of Parties' Positions:

In its October 1, 2008, ASC Filing, NWE functionalized Compensated Absences - Contra in Account 182.3 using the Labor Ratio.

Analysis of Positions:

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

The 2008 ASCM 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).

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.

The documentation submitted by NWE did not show that Compensated Absences - Contra costs are included in NWE's rate base by the Montana PSC.

Draft Decision:

Because NWE did not provide documentation showing that the cost associated with Compensated Absences - Contra was included in NWE's jurisdictional rate base, BPA will functionalize Compensated Absences - Contra to Distribution.

Table 4.3.3: Account 182.3 Other Regulatory Assets: Compensated Absences - Contra ($)

	Total	Production	Transmission	Dist/Other
As-Filed	(188,943)	(3,409)	(33,755)	(151,779)
BPA Adjusted	(188,943)	0	0	(188,943)

4.3.4. Account 182.3 Other Regulatory Assets - Compensated Absences

Statement of Issue:

Has NWE properly calculated and appropriately functionalized its Other Regulatory Assets: Compensated Absences, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does NWE's documentation submitted with its ASC filing constitute a valid direct analysis? Should the costs associated with Compensated Absences be functionalized using the Labor Ratio?

Statement of Facts:

NWE's January 30, 2009, response to BPA's December 1, 2008, Data Request No.8 stated:

> The following line items are related to employee benefits recorded on the books as total amounts (common) and require an allocation between electric and natural gas (see response to BPA-NW-10 for the common allocation factor):
>
> - Compensated Absences/Contra & Compensated Absences
> - FAS 106 & FAS 112
> - Net Regulatory Asset - Pension Plan

In NWE's January 30, 2009, response to BPA's December 1, 2008, Data Request No.14, NWE stated:

> - Compensated Absences: Relates to vacation accruals and employee benefits that encompass all functions, should be allocated based on labor.
> - FAS 1061FAS 112lPension: Relates to employee benefits that encompass all functions, should be allocated based on labor.

In response to Data Request BPA-NW-14, asking if the Compensated Absences were included in NWE's jurisdictional rate base, NWE replied:

> The final result of NWE's filing is a stipulation in which the Account 182.3 amounts are included as filed.

However, the next document following the above statement indicated that Compensated Absences are not in NWE's jurisdictional rate base. The "Comments" column on the table stated:

> Consistent with historical regulatory treatment, the cost of service used to establish rates has historically included vacation on a cash basis. Represents difference between cash and accrual.

In the same document, under the column titled "Rate Base" where other items were listed as "yes" or "no", NWE stated the Compensated Absences were "Offset by benefit liability."

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

In its October 1, 2008, ASC Filing, NWE functionalized Compensated Absences in Account 182.3 using the Labor Ratio.

<u>Analysis of Positions:</u>

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

The 2008 ASCM 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).

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.

The documentation submitted by NWE did not show that Compensated Absences costs are included in NWE's rate base by the Montana PSC.

<u>Draft Decision</u>:

Because NWE did not provide documentation showing that the cost associated with Compensated Absences - Contra was included in NWE's jurisdictional rate base, BPA will functionalize Compensated Absences - Contra to Distribution.

Table 4.3.4: Account 182.3 Other Regulatory Assets: Compensated Absences ($)

	Total	Production	Transmission	Dist/Other
As-Filed	3,350,449	60,449	598,565	2,691,435
BPA Adjusted	3,350,449	0	0	3,350,449

4.3.5. Account 182.3 Other Regulatory Assets - Compensated Absences - Contra

Statement of Issue:

Has NWE properly calculated and appropriately functionalized its Other Regulatory Assets: Compensated Absences - Contra, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does NWE's documentation submitted with its ASC filing constitute a valid direct analysis? Should the costs associated with Compensated Absences - Contra be functionalized using the Labor Ratio?

Statement of Facts:

NWE's January 30, 2009, response to BPA's December 1, 2008, Data Request No.8 stated:

> The following line items are related to employee benefits recorded on the books as total amounts (common) and require an allocation between electric and natural gas (see response to BPA-NW-10 for the common allocation factor):
> - Compensated Absences/Contra & Compensated Absences
> - FAS 106 & FAS 112
> - Net Regulatory Asset - Pension Plan

In NWE's January 30, 2009, response to BPA's December 1, 2008, Data Request No.14, NWE stated:

- Compensated Absences: Relates to vacation accruals and employee benefits that encompass all functions, should be allocated based on labor.
- FAS 106/FAS 112 Pension: Relates to employee benefits that encompass all functions, should be allocated based on labor.

In response to Data Request BPA-NW-14, asking if the Compensated Absences was included in NWE's jurisdictional rate base, NWE replied:

> The final result of NWE's filing is a stipulation in which the Account 182.3 amounts are included as filed.

However, the next document following the above statement indicated that Compensated Absences are not in NWE's jurisdictional rate base. The "Comments" column on the table stated:

FAS 112 - costs are recovered on a funding basis. This reflects accruals in excess of funding.

On the same document, under the column entitled "Rate Base" where other items were listed as "yes" or "no", NWE stated that the Post Employment Benefits were "Offset by benefit liability."

Summary of Parties' Positions:

In its October 1, 2008, ASC Filing, NWE functionalized Compensated Absences - Contra in Account 182.3 using the Labor Ratio. The detail provided by NWE was "Employee benefits alloc on labor."

Analysis of Positions:

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

The 2008 ASCM 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).

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.

The documentation submitted by NWE did not show that Compensated Absences - Contra costs are included in NWE's jurisdictional rate base by the Montana PSC.

Draft Decision:

Because NWE did not provide documentation showing that the cost associated with Compensated Absences - Contra was included in NWE's jurisdictional rate base, BPA will functionalize Compensated Absences - Contra to Distribution.

**Table 4.3.5: Account 182.3 Other Regulatory Assets:
Compensated Absences - Contra ($)**

	Total	Production	Transmission	Dist/Other
As-Filed	19,820,325	357,601	3,540,945	15,921,779
BPA Adjusted	19,820,325	0	0	19,820,325

4.3.6. Account 182.3 Other Regulatory Assets - Compensated Absences

Statement of Issue:

Has NWE properly calculated and appropriately functionalized its Other Regulatory Assets: Compensated Absences in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does NWE's documentation submitted with its ASC filing constitute a valid direct analysis? Should the costs associated with Compensated Absences be functionalized using the Labor Ratio?

Statement of Facts:

In its October 1, 2008, ASC Filing, NWE functionalized Compensated Absences - Contra in Account 182.3 using the Labor Ratio. The detail provided by NWE was "Employee benefits alloc on labor."

NWE's January 30, 2009, response to BPA's December 1, 2008, Data Request No.8 stated:

> The following line items are related to employee benefits recorded on the books as total amounts (common) and require an allocation between electric and natural gas (see response to BPA-NW-10 for the common allocation factor):
>
> - Compensated Absences/Contra & Compensated Absences
> - FAS 106 & FAS 112
> - Net Regulatory Asset - Pension Plan

In NWE's January 30, 2009, response to BPA's December 1, 2008, Data Request No.14, NWE stated:

- Compensated Absences: Relates to vacation accruals and employee benefits that encompass all functions, should be allocated based on labor.
- FAS 106/FAS 112 Pension: Relates to employee benefits that encompass all functions, should be allocated based on labor.

In response to Data Request BPA-NW-14, asking if the Compensated Absences were included in NWE's jurisdictional rate base, NWE replied:

> The final result of NWE's filing is a stipulation in which the Account 182.3 amounts are included as filed.

However, the next document following the above statement indicated that Compensated Absences are not in NWE's jurisdictional rate base. The "Comments" column on the table stated:

> FAS 112 - costs are recovered on a funding basis. This reflects accruals in excess of funding.

In the same document, under the column entitled "Rate Base" where other items were listed as "yes" or "no", NWE stated that the Post Employment Benefits were "Offset by benefit liability."

Summary of Parties' Positions:

In its October 1, 2008, ASC Filing, NWE functionalized Compensated Absences - Contra in Account 182.3 using the Labor Ratio.

Analysis of Positions:

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

The 2008 ASCM 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).

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.

The documentation submitted by NWE did not show that Compensated Absences - Contra costs are included in NWE's jurisdictional rate base by the Montana PSC.

Draft Decision:

Because NWE did not provide documentation showing that the cost associated with Compensated Absences - Contra was included in NWE's jurisdictional rate base, BPA will functionalize Compensated Absences - Contra to Distribution.

Table 4.3.6 Account 182.3 Other Regulatory Assets: Compensated Absences ($)

	Total	Production	Transmission	Dist/Other
As-Filed	2,683,122	48,409	479,346	2,155,367
BPA Adjusted	2,683,122	0	0	2,683,122

4.3.7. Account 182.3 Other Regulatory Assets: FAS 106

Statement of Issue:

Has NWE properly calculated and appropriately functionalized its Other Regulatory Liabilities: FAS 106 in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does NWE's documentation submitted with its ASC filing constitute a valid direct analysis? Should FAS 106 be functionalized using the Labor Ratio?

Statement of Facts:

In its October 1, 2008, ASC Filing, NWE functionalized FAS 106 in Account 182.3 using the Labor Ratio. The detail provided by NWE was "Employee benefits alloc on labor."

NWE's January 30, 2009, response to BPA's December 1, 2008, Data Request No.8, stated:

> The following line items are related to employee benefits recorded on the books as total amounts (common) and require an allocation between electric and natural gas (see response to BPA-NW-10 for the common allocation factor):
>
> - Compensated Absences/Contra & Compensated Absences
> - FAS 106 & FAS 112
> - Net Regulatory Asset - Pension Plan

In NWE's January 30, 2009, response to BPA's December 1, 2008, Data Request No.14, NWE stated:

- Compensated Absences: Relates to vacation accruals and employee benefits that encompass all functions, should be allocated based on labor.
- FAS 106/FAS 112 Pension: Relates to employee benefits that encompass all functions, should be allocated based on labor.

In response to Data Request BPA-NW-14, asking if FAS 106 was included in NWE's jurisdictional rate base, NWE replied:

> The final result of NWE's filing is a stipulation in which the Account 182.3 amounts are included as filed.

However, the next document following the above statement indicated that Compensated Absences are not in NWE's jurisdictional rate base. The "Comments" column on the table stated:

> This amount represents the FAS 106 costs accrued prior to the time the accounting pronouncement was reflected in cost of service. The amount is recovered over a transition period.

In the same document, under the column entitled "Rate Base" where other items were listed as "yes" or "no", NWE stated that the difference between actual funding and modified funding is rate based for 'Reg Asset Pension Pl'. The documentation provided by NWE did identify the amount of the pension plan costs included in rate base.

Summary of Parties' Positions:

In its October 1, 2008, ASC Filing, NWE functionalized FAS 106 in Account 182.3 using the Labor Ratio.

Analysis of Positions:

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

The 2008 ASCM 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).

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.

The documentation submitted by NWE did not show that FAS 106 costs are included in NWE's jurisdictional rate base by the Montana PSC.

Draft Decision:

Because NWE did not provide documentation showing that the cost associated with FAS 106 was included in NWE's jurisdictional rate base, BPA will functionalize FAS 106 to Distribution.

Table 4.3.7: Account 182.3 Other Regulatory Assets: FAS 106 ($)

	Total	Production	Transmission	Dist/Other
As-Filed	52,936,099	955,081	9,457,151	42,523,867
BPA Adjusted	52,936,099	0	0	52,936,099

4.3.8. Account 303.1 Common Plant Intangible - Software

Statement of Issue:

Has NWE properly calculated and appropriately functionalized its Common Plant Intangible - Software in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does NWE's documentation submitted with its ASC filing constitute a valid direct analysis? Should the costs associated with Common Plant Intangible - Software be functionalized using the PTD ratio?

Statement of Facts:

NWE functionalized the software in Account 303.1 using the PTD ratio. The documentation included in NWE's ASC filing and in response to BPA Data Request BPA-NW-7 and BPA-NW-19 was not sufficient to determine if PTD is the correct functionalization for this Account.

During a February 20, 2009, BPA on-site visit to NWE, BPA requested additional information describing the software. NWE replied on February 27, 2009, with BPA.ONSITE – NW-5, which included a table with a detailed listing of the individual software in Account 303.1. However, BPA was unable to determine the net plant and accumulated depreciation associated with each item.

During its review of other ASC filings, BPA noticed that direct analyses performed by the utilities resulted in different functionalizations for similar types of software. For example, metering and customer information system (CIS) software was functionalized to Distribution by PGE while PacifiCorp, PSE, NWE, Avista and Idaho functionalized such software using the PTD ratio.

In addition, two utilities, Avista and Idaho, chose not to perform additional direct analysis on software costs included in Account 303 and functionalized all software costs to Distribution.

Summary of Parties' Positions:

NWE functionalized the software in Account 303.1 using the PTD ratio.

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 argued 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 NWE 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 NWE, 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.

NWE'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:

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

The 2008 ASCM states "Functionalization of each Account included in a Utility's Average System Cost (ASC) shall be according to the functionalization prescribed in Table 1, *Functionalization and Escalation Codes*, beginning on page 18. Direct Analysis on an Account may be performed only if Table 1 states specifically that a Utility may perform a Direct Analysis on the Account with the exception of conservation costs. Utilities will be able to functionalize all conservation-related costs to Production, regardless of the Account in which they are recorded." *Id* at 16.

When utilities perform a direct analysis on an Account, they must submit sufficient documentation so that BPA can determine if the functionalization is reasonable. In addition, the 2008 ASCM states that "BPA will not allow Utilities to use a combination of Direct Analysis and a prescribed functionalization method for the same Account. The Utilities can develop and use a functionalization ratio or use a prescribed functionalization method if the Utility through Direct Analysis can justify how the ratio adequately reflects the functional nature of the costs included in any Account or cost item being functionalized by the ratio." *Id. at 17*.

BPA's review of the initial ASC filings revealed that most utilities either used the PTD or Labor ratio to functionalize a majority of Account 303 software. However, the functionalization methodology and rationale for the direct analysis was not consistent among utilities. Some of the statements included by utilities to support functionalization of a specific piece of software using the PTD ratio used terms like "supports all functions of the company"[4] or "supports all areas of the company."[5] These catchall phrases, if taken to the extreme, could be used to rationalize using the PTD ratio to functionalize the entire ASC filing using the PTD ratio. Such simple statements do not constitute a valid direct analysis.

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

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

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

> 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.

[4] See, for example, Data Responses ASC-09 PA-BPA-12 and ASC-09-PS-BPA-6
[5] 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.

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

Draft Decision:

BPA will functionalize Account 303.1 to Distribution because it was unable to determine from the information supplied by NWE how to functionalize software systems using the framework developed by BPA and described below in Section 6.1.1. Prospectively, BPA will work with NWE to functionalize the software in Account 301.1 using BPA's software functionalization framework.

Table 4.3.8: Account 303.1 Common Plant Intangible - Software: ($)

	Total	Production	Transmission	Dist/Other
As-Filed	6,176,033	13,135	1,466,553	4,696,345
BPA Adjusted	6,176,033	0	0	6,176,033

4.3.9. Account 303.2 Common Plant Intangible - Software

Statement of Issue:

Has NWE properly calculated and appropriately functionalized its Account 303.2 Common Plant Intangible - Software in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does NWE's documentation submitted with its ASC filing constitute a valid direct analysis? Should the costs associated with Account 303.2 Common Plant Intangible - Software be functionalized using the PTD ratio?

Statement of Facts:

NWE functionalized the software in Account 303.2 using the PTD ratio. The documentation included in NWE's ASC filing and in response to BPA Data Request BPA-NW-7 and BPA-NW-19 was not sufficient to determine if PTD is the correct functionalization for this Account.

During a February 20, 2009, BPA on-site visit to NWE, BPA requested additional information describing the software. NWE replied on February 27, 2009, with BPA.ONSITE – NW-5, which included a table with a detailed listing of the individual software in Account 303.2. Software items in this Account are related to NWE's SAP installation.

During review of other ASC filings, BPA noticed that direct analyses performed by the utilities resulted in different functionalizations for similar types of software. For example, metering and customer information system (CIS) software was functionalized to Distribution by PGE while PacifiCorp, Puget, NWE, Avista and Idaho functionalized such software using the PTD ratio.

In addition, two utilities, Avista and Idaho, chose not to perform additional direct analysis on software costs included in Account 303 and functionalized all software costs to Distribution.

Summary of Parties' Positions:

NWE functionalized the software in Account 303.2 using the PTD ratio.

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:

> 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 argued 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 NWE 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 NWE, 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.

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

> 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.

<u>Analysis of Positions</u>:

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

The 2008 ASCM states "Functionalization of each Account included in a Utility's Average System Cost (ASC) shall be according to the functionalization prescribed in Table 1, *Functionalization and Escalation Codes*, beginning on page 18. Direct Analysis on an Account may be performed only if Table 1 states specifically that a Utility may perform a Direct Analysis on the Account with the exception of conservation costs. Utilities will be able to functionalize all conservation-related costs to Production, regardless of the Account in which they are recorded." *Id at 16.*

When utilities perform a direct analysis on an Account, they must submit sufficient documentation so that BPA can determine if the functionalization is reasonable. In addition, the 2008 ASCM states that "BPA will not allow Utilities to use a combination of Direct Analysis and a prescribed functionalization method for the same Account. The Utilities can develop and use a functionalization ratio or use a prescribed functionalization method if the Utility through Direct Analysis can justify how the ratio adequately reflects the functional nature of the costs included in any Account or cost item being functionalized by the ratio." *Id. at 17*.

BPA's review of the initial ASC filings revealed that most utilities either used the PTD or Labor ratio to functionalize a majority of Account 303 software. However, the functionalization methodology and rationale for the direct analysis was not consistent among utilities. Some of the statements included by utilities to support functionalization of a specific piece of software using the PTD ratio used terms like "supports all functions of the company"[6] or "supports all areas of

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

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 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 will receive the same functionalization for all exchanging utilities to the greatest extent possible. In addition, it should allow utilities that decided not to undertake the task of functionalization of Account 303 – Software an "easy to use" framework for functionalization.

BPA's software cost functionalization framework functionalizes cost related to Enterprise Resource Planning ERP systems using the Labor ratio because the primary benefit of ERP

[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.

systems is increased productivity of the utility's work force. ERP systems are not installed to reduce line losses or increase heat rates of power generation equipment. While utilities may experience an increase in the productivity of assets, the cause is a result of the more accurate, timely and higher quality information provided to labor, thus resulting in a more efficient use of utility assets.

Draft Decision:

BPA will functionalize Account 303.2 using the Labor Ratio.

Table 4.3.9: Account 303.1 Common Plant Intangible - Software: ($)

	Total	Production	Transmission	Dist/Other
As-Filed	14,565,291	30,978	3,458,655	11,075,658
BPA Adjusted	14,565,291	262,789	2,602,121	11,700,380

4.3.10. Common Plant Accounts 389 through 398

Statement of Issue:

Has NWE properly calculated and appropriately functionalized its Common Plant Accounts 389 through 398 in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does NWE's documentation submitted with its ASC filing constitute a valid direct analysis? Should the costs associated with Common Plant Accounts 389 through 398 be functionalized using the PTD Ratio?

Statement of Facts:

NWE functionalized Common Plant Accounts 389 through 398 using the PTD Ratio. The documentation included in NWE's ASC filing stated that the Common Plant Accounts "are land buildings and communication equipment similar to electric general plant. Functionalization is based on the same PTD allocators." No other documentation was provided.

Summary of Parties' Positions:

NWE functionalized Common Plant Accounts 389 through 398 using the PTD Ratio.

Analysis of Positions:

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

The 2008 ASCM states "Functionalization of each Account included in a Utility's Average System Cost (ASC) shall be according to the functionalization prescribed in Table 1, *Functionalization and Escalation Codes*, beginning on page 18. Direct Analysis on an Account may be performed only if Table 1 states specifically that a Utility may perform a Direct Analysis on the Account with the exception of conservation costs. Utilities will be able to functionalize all conservation-related costs to Production, regardless of the Account in which they are recorded." *Id at 16.*

When utilities perform a direct analysis on an Account, they must submit sufficient documentation so that BPA can determine if the functionalization is reasonable. In addition, the 2008 ASCM states that "BPA will not allow Utilities to use a combination of Direct Analysis and a prescribed functionalization method for the same Account. The Utilities can develop and use a functionalization ratio or use a prescribed functionalization method if the Utility through Direct Analysis can justify how the ratio adequately reflects the functional nature of the costs included in any Account or cost item being functionalized by the ratio." *Id. at 17*.

NWE did not provide support for its use of the PTD ratio to functionalize general plant Accounts 389 through 398. NWE provides both natural gas and electricity to retail customers. Common plant is plant that is used by both divisions of the company. Section 13 of the Electric Plant Instructions contained in the FERC Uniform System of Accounts states:

> If the utility is engaged in more than one utility service, such as electric, gas, and water, and any of its utility plant is used in common for several utility services or for other purposes to such an extent and in such manner that it is impracticable to segregate it by utility services currently in the accounts, such property, with the approval of the Commission, may be designated and classified as common utility plant.
>
> The original cost of common utility plant in service shall be classified according to detailed utility plant accounts appropriate for the property. *18 CFR Ch. 1 Part 101 at 386.*

The 2008 ASCM contains functionalization rules for Accounts 389 through 398. There is not separate set of Account definitions and descriptions in the FERC Uniform System of Accounts for Common Plant Accounts 389 through 398. Utilities gather common plant costs using standard FERC Account structure, and then record the total as Common Plant. Utilities then perform an analysis that separates common plant between the electric and gas divisions of the utility. The amount shown on the FERC Form 1 is the electric portion.

Draft Decision:

Because NWE did not provide adequate support for its use of the PTD ratio to functionalize Common Plant Accounts 389 through 398, BPA will use the functionalization for Accounts 389 through 398 contained on Table 1 of the 2008 ASCM.

NWE As-Filed Common Plant					
Common Plant	**Funct.**	**Plant**	**Production**	**Transmission**	**Distribution**
Account No. 389	**PTD**	1,979,074	4,209	469,948	1,504,916
Account No. 389.6	**PTD**	113,871	242	27,040	86,589
Account No. 390	**PTD**	20,544,500	43,695	4,878,471	15,622,335
Account No. 390.6	**PTD**	981,759	2,088	233,127	746,544
Account No. 391	**PTD**	2,111,735	4,491	501,450	1,605,794
Account No. 391.1	**PTD**	1,981,257	4,214	470,467	1,506,576
Account No. 391.2	**PTD**	2,294,905	4,881	544,945	1,745,079
Account No. 397.1	**PTD**	5,068,285	10,779	1,203,508	3,853,997
Account No. 397.3	**PTD**	2,735,104	5,817	649,474	2,079,813
Account No. 398	**PTD**	769,883	1,637	182,815	585,430
Total		**$38,580,374**	**$82,054**	**$9,161,246**	**$29,337,074**

NWE As-Amended Common Plant					
Common Plant	**Funct.**	**Plant**	**Production**	**Transmission**	**Distribution**
Account No. 389	**PTD**	1,979,074	4,209	469,948	1,504,916
Account No. 389.6	**PTD**	113,871	242	27,040	86,589
Account No. 390	**PTD**	20,544,500	43,695	4,878,471	15,622,335
Account No. 390.6	**PTD**	981,759	2,088	233,127	746,544
Account No. 391	**LABOR**	2,111,735	38,100	377,266	1,696,369
Account No. 391.1	**LABOR**	1,981,257	35,746	353,956	1,591,555
Account No. 391.2	**LABOR**	2,294,905	41,405	409,990	1,843,510
Account No. 397.1	**PTD**	5,068,285	10,779	1,203,508	3,853,997
Account No. 397.3	**PTD**	2,735,104	5,817	649,474	2,079,813
Account No. 398	**PTD**	769,883	1,637	182,815	585,430
Total		**$38,580,374**	**$183,720**	**$8,785,596**	**$29,611,059**

NWE As-Filed Common Plant Depreciation Reserve					
Common Plant	**Funct.**	**Plant**	**Production**	**Transmission**	**Distribution**
Account No. 389	**PTD**	113,757	242	27,013	86,502
Account No. 389.6	**PTD**	599	1	142	455
Account No. 390	**PTD**	(4,472,486)	(9,512)	(1,062,031)	(3,400,943)
Account No. 390.6	**PTD**	(102,684)	(218)	(24,383)	(78,082)
Account No. 391	**PTD**	(1,753,777)	(3,730)	(416,450)	(1,333,597)
Account No. 391.1	**PTD**	(1,660,104)	(3,531)	(394,206)	(1,262,367)
Account No. 391.2	**PTD**	(861,354)	(1,832)	(204,536)	(654,986)
Account No. 397.1	**PTD**	(1,530,768)	(3,256)	(363,494)	(1,164,018)
Account No. 397.3	**PTD**	(2,710,594)	(5,765)	(643,654)	(2,061,175)
Account No. 398	**PTD**	(581,999)	(1,238)	(138,201)	(442,560)
Total		**($13,559,410)**	**($28,839)**	**($3,219,800)**	**($10,310,771)**

NWE As-Amended Common Plant Depreciation Reserve					
Common Plant	**Funct.**	**Plant**	**Production**	**Transmission**	**Distribution**
Account No. 389	**PTD**	113,757	242	27,013	86,502
Account No. 389.6	**PTD**	599	1	142	455
Account No. 390	**PTD**	(4,472,486)	(9,512)	(1,062,031)	(3,400,943)
Account No. 390.6	**PTD**	(102,684)	(218)	(24,383)	(78,082)
Account No. 391	**LABOR**	(1,753,777)	(31,642)	(313,316)	(1,408,819)
Account No. 391.1	**LABOR**	(1,660,104)	(29,952)	(296,581)	(1,333,571)
Account No. 391.2	**LABOR**	(861,354)	(15,541)	(153,883)	(691,930)
Account No. 397.1	**PTD**	(1,530,768)	(3,256)	(363,494)	(1,164,018)
Account No. 397.3	**PTD**	(2,710,594)	(5,765)	(643,654)	(2,061,175)
Account No. 398	**PTD**	(581,999)	(1,238)	(138,201)	(442,560)
Total		**($13,559,410)**	**($96,880)**	**($2,968,388)**	**($10,494,141)**

4.4. Schedule 1A: Cash Working Capital

No direct adjustment.

4.5. Schedule 2: Capital Structure and Rate of Return

4.5.1. Rate of Return

Statement of Issue:

Is use of a Return on Equity (ROE) from a 2000 Montana Public Service Commission(MPSC) rate order for Montana Power Company a reasonable proxy for NorthWestern Energy's ROE?

Statement of Facts:

NWE does not have a rate order from the MPSC that includes a ROE since the date NWE purchased the Montana Power Company service territory in 2000. NWE submitted a rate order from the MPSC, Docket No. D2000.8.113 Final Order 6271c, which authorized a capital structure for Montana Power Company, including a return on common equity of 10.75%.

NWE's February 11, 2009, response to BPA's Issue List stated:

> NWE does in fact have several rate orders from the MPSC since purchasing the Montana Power Company. It does not have a revenue requirement order specifically identifying a rate of return. The Stipulation approved by the MPSC in the most recent revenue requirement filing (Docket No. D2007.7.82) is silent on NWE's capital structure and rate of return. However, the monthly and annual supply tracker filings, as well as various analyses, continue to be based on the last MPSC authorized rate of return. For this reason, NWE believes use of this return reflects current regulatory treatment and is appropriate to use in the Appendix 1 filing.

Summary of Parties' Positions:

NWE argues the last MPSC-approved rate of return for Montana Power Company should be used as NWE's rate of return.

Analysis of Positions:

Endnote b to the 2008 ASCM states:

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

NWE's situation is unique due the absence of a MPSC rate order specifying an equity return for NWE. NWE acquired Montana Power Company's electricity and natural gas distribution business in 2000. NWE rate orders from the MPSC since the purchase have not addressed equity return or cost of capital. The MPSC orders concerning requests for changes in NWE retail rates have been in the form of supply trackers or stipulations.

BPA compared the ROE and capital structure submitted by NWE in this filing with similar information submitted by other IOUs in their Appendix 1 filings and finds NWE's proposed 10.75% ROE is reasonable. The following table compares the allowed ROE for the other IOUs in their 2009 ASC Appendix 1 filings.

Utility	Allowed ROE	ASC Rate of Return
Avista		**11.17%**
Avista – Washington	10.20%	
Avista – Idaho	10.40%	
Idaho Power		**10.94%**
Idaho Power – Idaho	10.60%	
Idaho Power – Oregon	10.00%	
NorthWestern	**10.75%**	**11.20%**
PacifiCorp		**10.86%**
PacifiCorp – Idaho	10.25%	
PacifiCorp – Oregon	10.00%	
PacifiCorp – Washington	10.20%	
Portland General Electric	**10.10%**	**11.09%**
Puget Sound Power and Light	**10.40%**	**10.87%**
Average		**11.02%**

While NWE's ASC rate of return is the highest rate of return among the filing IOUs, it is only fractionally higher, 0.03%, than Avista's return, the next highest return, and 0.18% higher than the average return of all filing utilities for the 2009 ASC filings.

BPA has the authority to review the reasonableness of PUC-allowed return on equity and cost of capital calculations filing utilities submit with their ASC filings. During the ASC Review Process, if BPA determines that a PUC-allowed return on equity or cost of capital is not reasonable for use in the utility's ASC filing, BPA will make an independent determination of the utility's return on equity and cost of capital calculation. The 2008 ASCM, Section III, Paragraph 3 states:

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

Based on BPA's review of the NWE's ROE and cost of capital submitted with its Appendix 1 filing, and comparison with ROEs and cost of capital calculations submitted by other IOUs in their 2009 ASC filings, BPA will accept NWE's proposed ROE and capital structure.

Draft Decision:

BPA will accept the August 2000 MPSC-allowed return on equity and cost of capital calculation from the 2000 Montana Power Company rate order as a reasonable proxy for NWE's return on equity and cost of capital calculation for ASC purposes for this filing only. Continued use of the

August 2000 MPSC order as a proxy for NWE's return on equity and cost of capital calculation will be made on a case by case basis.

4.6. Schedule 3: Expenses

4.6.1. Account 565 – Transmission of Electricity by Others - Wheeling

Statement of Issue:

Did NWE properly calculate and appropriately functionalize Account 565 – Transmission of Electricity by Others – Wheeling in accordance with the requirements of the functionalization rules of the 2008 ASCM?

Statement of Facts:

NWE's Appendix 1 template functionalized a portion of Account 565 to Distribution. Supporting documentation submitted with its Appendix 1 indicated that it functionalized Account 565 using a direct analysis.

In its February 11, 2009, response to BPA's Issue List, NWE stated:

> NWE incorrectly included an allocation reflecting separation of transmission and distribution lines. Upon further analysis after the Appendix 1 filing was made, NWE recognizes that the lines associated with this account are those owned by other entities and used by NWE. Therefore, 100% of the costs in Account 565 should be functionalized to Transmission.

Summary of Parties' Positions:

NWE proposes to functionalize Account 565 to Transmission.

Analysis of Positions:

Table 1 of the 2008 ASCM provides that the functionalization method for this account is Transmission with no optional functionalization.

Section VIII.of 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. The Direct Analysis must be consistent with the directions provided below.

The ability of utilities to functionalize all accounts was raised as an issue and decided in the 2008 ASCM ROD, which states:

> The ASCM will permit direct analysis only for specified accounts. The ASCM contains default functionalization methods in the absence of direct analysis where appropriate.

2008 ASCM ROD at 29. This statement is reiterated in the 2008 ASCM ROD in Section 4.3 Functionalization Codes:

> A direct analysis may be performed only if Table 1 indicates that a Utility may perform a direct analysis on the Account. The only exception to this requirement is for conservation-related costs. Because the FERC Form 1 does not contain a specific set of accounts for conservation-related costs, Utilities record those costs in a variety of FERC accounts. *Id.* at 67.

Account 565 – Transmission of Electricity by Others – Wheeling was not listed in the 2008 ASCM ROD or the 2008 ASCM as an Account where direct analysis was permitted.

Draft Decision:

Utilities are not permitted to use direct analysis to functionalize an Account except when specifically permitted based on Table 1 of the 2008 ASCM. BPA will functionalize Account 565 to Transmission.

4.6.2. Account 930.2 – Miscellaneous General Expenses- Conservation Program Costs

Statement of Issue:

Did NWE properly calculate and appropriately functionalize Account 930.2 – Miscellaneous General Expenses-Conservation Program Costs in accordance with the requirements of the functionalization rules of the 2008 ASCM?

Statement of Facts:

NWE's February 6, 2009, response to BPA's December 1, 2008, Data Request No.2 supplied documentation that supported NWE's direct analysis of this account. BPA's review of NWE's documentation revealed that many of the conservation costs that were functionalized to Distribution appeared to be valid conservation program expenses that should be functionalized to Production.

During a February 20, 2009, BPA onsite visit to NWE, BPA requested additional information describing the costs in Account 930.2 and informed NWE Staff that all conservation-related expenses including advertising and promotion expenses can be functionalized to Production. NWE Staff indicated it would review the items in Account 930.2 and resubmit the documentation to BPA.

NWE replied on February 27, 2009, with BPA.ONSITE – NW-2, which included a much more detailed table with various line items functionalized either to Production or Distribution. BPA's review of this data revealed that NWE still may have functionalized valid conservation-related program costs to Distribution.

Summary of Parties' Positions:

NWE proposes to functionalize a portion of Account 930.2 – Miscellaneous General Expenses-Conservation Program Costs to Production.

Analysis of Positions:

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

> A direct analysis may be performed only if Table 1 indicates that a Utility may perform a direct analysis on the Account. The only exception to this requirement is for conservation-related costs. Because the FERC Form 1 does not contain a specific set of accounts for conservation-related costs, Utilities record those costs in a variety of FERC accounts.

Id. at 67. Most of the costs included in Account 930.2 are related to conservation program expenses that are funded by the MPSC Universal Systems Benefit Charge. NWE performed a direct analysis on this Account 930.2 and functionalized a portion of this account to Production.

Section VIII, Paragraph A of 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.

Paragraph B.1 of Section VIII states further that:

> Utilities will be able to identify and functionalize to Production any conservation-related costs, irrespective of the Account in which they are recorded. Such analysis is subject to BPA review and approval.

In addition, Paragraph B.3 of Section VIII states:

> Utilities that wish to include advertising and promotion costs related to conservation will do so with a Direct Analysis. If a Utility records conservation costs in an Account that is normally functionalized to Distribution/Other, the Utility will identify and document the conservation related costs included in the Account, and the balance of the costs will be

functionalized to Distribution/Other. The presence of conservation-related costs in an Account does not give the Utility permission to perform a Direct Analysis on the entire Account.

<u>Draft Decision</u>:

BPA accepts NWE's revised direct analysis and will functionalize this account based on the direct analysis. However, BPA encourages NWE to review Account 930.2 again to ensure that all valid conservation related program costs are functionalized to Production. Prospectively, BPA will work with NWE Staff to review the items in Account 930.2 and allow NWE to resubmit a revision to its direct analysis on this Account.

Table 4.6.1: Account 930.2 Miscellaneous General Expenses - Conservation Costs ($)

	Total	Production	Transmission	Dist/Other
As-Filed	10,688,250	1,677,454	0	9,010,796
BPA Adjusted	10,688,250	5,690,105	0	4,998,145

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

No direct adjustment.

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

4.8.1. Account 456.1 – Revenue from the Transmission of Electricity of Others

<u>Statement of Issue</u>:

Did NWE properly calculate and appropriately functionalize Account 456.1, Revenue from the Transmission of Electricity of Others, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology?

<u>Statement of Facts</u>:

NWE's Appendix 1 template functionalized a portion of Account 456.1 to Distribution. Supporting documentation submitted with its Appendix 1 indicated that it functionalized Account 456.1 using a direct analysis based on FERC's Seven Factor Test. NWE's analysis indicated that 34% of its total transmission plant was distribution-related. Based on this analysis, NWE functionalized 34% of Account 456.1 to Distribution.

NWE does not have an order from the MPSC separating its transmission plant between transmission and distribution using FERC's Seven Factor Test.

In its February 11, 2009, response to BPA's Issue List, NWE stated:

According to Attachment A of the 2008 ASC Methodology

> "…if a Utility…has not received an order from its Regulatory Body separating its line between transmission and distribution, then it must perform a Direct Analysis on its transmission costs and wheeling revenues. The Direct Analysis must allocate transmission costs and wheeling revenues so that only the costs and revenues of transmission lines rated at 115kV or above are included as transmission."

Because NWE does not have an order addressing separation of transmission and distribution lines, the Appendix 1 filing prepared by NWE includes an allocation to transmission and distribution. Within the template, for plant and O&M expenses, NWE subtracted the amount allocated to distribution from transmission and added the same amount to distribution. NWE followed the same process for the revenue. NWE agrees that only the transmission allocated revenue is appropriate, however, it is not clear where on Schedule 3B the distribution allocated revenue would be included. If the utility had an approved separation of transmission and distribution lines, the revenue for the distribution lines would probably be recovered through retail rate schedule revenue. Since there is no line item on Schedule 3B related to this type of revenue, NWE would accept an appropriate alternative to what was provided in the initial Appendix 1 filing.

Summary of Parties' Positions:

NWE's Appendix 1 template functionalized a portion of Account 456.1 to Distribution. Supporting documentation submitted with its Appendix 1 indicated that it functionalized Account 456.1 using a direct analysis based on FERC's Seven Factor Test. NWE's analysis indicated that 34% of its total transmission plant was distribution-related. Based on this analysis, NWE functionalized 34% of Account 456.1 to Distribution.

Analysis of Position:

Table 1 of the 2008 ASCM provides that the functionalization method for this account is Transmission with no optional functionalization.

The description of Account 456.1 in the FERC Uniform System of Accounts states that

> This account shall include revenues from transmission of electricity of others over transmission facilities of the utility.

NWE's October 1, 2008, Appendix 1 included an analysis that classified transmission plant between transmission and distribution based on rules from FERC's Seven Factor Test contained in Order No. 890. The analysis contained on tab *Tran Plt Functionalized* in the Appendix 1 spreadsheet and tab *Tran Plt_Voltage_Functionalized* in the Supporting WP file resulted in 34% of NWE's transmission plant classified as Distribution. NWE's Appendix 1 template functionalized a portion of Account 456.1 to Distribution. Supporting documentation submitted with its Appendix 1 indicated that it functionalized Account 565 using a direct analysis based on FERC's Seven Factor Test. NWE's analysis indicated that 34% of its total transmission plant was distribution-related.

One of the components of FERC Order 888 was a methodology that utilities and state commissions could use to determine which facilities that currently are included in transmission plant could be reclassified as distribution and subject to the jurisdiction of the state commissions. This methodology is referred to as the Seven Factor Test. Utilities must request a finding from their state commissions that a refunctionalization of transmission plant to distribution plant is warranted. After utilities receive an order from their state commissions on refunctionalization of transmission plant, the plant and related O&M expense is transferred to distribution in the FERC Form 1 filing. The seven factors listed in FERC Order 888 are shown below:

1. Local distribution facilities are normally in close proximity to retail customers.
2. Local distribution facilities are primarily radial in character.
3. Power flows into local distribution systems; it rarely, if ever, flows out.
4. When power enters a local distribution system, it is not reconsigned or transported on to some other market.
5. Power entering a local distribution system is consumed in a comparatively restricted geographical area.
6. Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.
7. Local distribution systems will be of reduced voltage.

In NWE's ASC filing, it chose to use the results of its Seven Factor Test to functionalize Account 456.1 - Revenue from the Transmission of Electricity of Others, which is a credit to expenses and thus reduces ASC. NWE did not follow through with the analysis in the rest of its ASC filing. BPA notes that in NWE's ASC filing, the plant balances and related O&M expense were not moved from Transmission to Distribution.

Compliance with FERC Order 888 concerning the Seven Factor Test is a matter best left to the utilities and their state commissions. NWE's analysis falls short because it only functionalized Account 456.1 and BPA was unable to determine if NWE's analysis was compliant with FERC Order 888.

Draft Decision:

BPA rejects NWE's direct analysis and will functionalize Account 456.1, Revenue from the Transmission of Electricity of Others to Transmission.

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

	Total	Production	Transmission	Dist/Other
As-Filed	43,648,835	0	28,218,372	15,430,462
BPA Adjusted	43,648,835	0	0	43,648,835

4.9. SCHEDULE 4: Average System Cost

No direct adjustment.

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

NorthWestern submitted distribution loss calculations. A Distribution Loss Factor of 4.40 percent was used.

5.5. ASC FORECAST MODEL:

5.5.1. Purchased Power and Sales for Resale Price Spread

Statement of Issue:

Did NWE properly calculate the price spread between the purchased power and sales for resale on the 3-Year PP & OSS Worksheet tab of the Appendix 1 Model and enter the correct price spread in the ASC Forecast Model?

Statement of Facts:

The 3-Year PP & OSS Worksheet tab of NWE's Appendix 1 filing did not contain a calculation of the price spread between the price NWE pays for purchased power and the price it receives for market sales. The ASC Forecast Model filed by NWE included a price spread that was not documented.

The 3-Year PP & OSS Worksheet tab of NWE's Appendix 1 filing did not contain data for the years 2004 and 2005.

Summary of Parties' Positions:

NWE proposes to use a price spread of 11.56% as the difference between purchased power and sales for resale.

Analysis of Positions:

When developing the ASC Forecast Model, BPA discovered large differences between the price utilities paid for power purchases and the the price they received for market sales. BPA therefore concluded that it would be appropriate to develop separate market prices to forecast short-term market purchases (as defined by FERC) and sales for resale (as defined by FERC). Section IV B of the 2008 ASCM contains the methodology for calculating the separate prices, including the calculation of the price spread.

Section IV B of the 2008 ASCM states

1. BPA will escalate long–term and intermediate-term (as defined by FERC) firm purchased power costs and sales for resale revenues at the rate of inflation.
2. BPA will not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period will be used as the starting values. A Utility will then be allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue to be included in the Rate Period ASC.
3. BPA will use the method as described below to determine separate market prices to forecast short-term purchased power expense and sales for resale revenues to calculate Exchange Period ASCs:

    a. The Utility's average short-term purchased power price and short-term sales for resale price will be calculated for each year for the most recent three years of actual data (Base Period and prior two years).
    b. The mid-point between the Utility's average short term purchased power price and short term sales for resale price will be calculated for each of the years in 1.
    c. The percentage spread around the Utility's mid-point between the average short term purchase power price and short term sales for resale price will be calculated for each of the years in 1.
    d. A weighted average spread for the Utility's most recent three years of actual data (Base Period and prior two years) will then be calculated. The following weighting scale will be used:
        i. 3 times Base Period spread
        ii. 2 times (Base Period year minus 1) spread
        iii. 1 times (Base Period year minus 2) spread

    e. The Base Period mid-point price calculated in 2 will be escalated at the same rate as BPA's market price forecast.
    f. The weighted average spread calculated in 4 will then be applied to the forecasted mid-point calculated in 5 to determine the purchased power and sales for resale

price, to value purchased power expenses and sales for resale revenue to be included in Rate Period ASCs.

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

During a February 20, 2009, BPA on-site visit to NWE, BPA requested additional information on Account 555 - Purchased Power, and Account 447 - Sales for Resale. NWE replied on February 27, 2009, with BPA.ONSITE – NW-6, which stated

> The Purchased Power and Sales for Resale worksheet provided in the FY 10-FY 11 ASC filing is incorrect. Please see the attached which includes a revised worksheet and corresponding reconciliation to FERC Form 1. Note that 2005 is blank. In gathering the 2005 data it was determined that the information included in NorthWestern's FERC Form 1 for that year is not reliable. The column labeled "Statistical Classification, which identifies the type of service, was not recorded correctly-in-the year 2005. Therefore, analysis using this data may lead to inaccurate and misleading conclusions. For the years going forward, this information is correct.

The same problem exists for NWE's 2009 ASC Filing. Because of problems with data prior to 2006, BPA will have to use a single year, 2006 for the price spread calculation.

Because NWE did not document its price spread calculation, BPA made the calculation using information form NWE's Appendix 1 filing. If the price spread calculation is not accurate, the Exchange Period ASC will not be accurate.

BPA made adjustments to the OS category of purchased power for 2006 only for the purpose of calculating the price spread between purchased power and sales for resale. The OS category in Account 555 is for services that cannot be placed in the other FERC defined categories for purchased power. Among the services in NWE's OS category were regulatory amortization of QF costs, adjustments for default service and purchases from WAPA for NWE's South Dakota service territory.

BPA removed these items from the OS category because they are regulatory adjustments in the case of the QF and Default Supply costs and South Dakota is not in the Pacific Northwest region as defined by the Northwest Power Act.

The table below shows the revisions to the 3-YEAR PP & OSS Worksheet made by BPA and the resulting price spread of 12.52%. BPA will use 12.52% as the price spread in the ASC Forecast Model.

BONNEVILLE POWER ADMINSTRATION							
RESIDENTIAL PURCHASE AND SALE AGREEMENT							
2008 Average System Cost Methodology							
			NorthWestern Energy				
			December 2006				
			October 1, 2008				
FERC Form 1		Purchased Power - Base Period		Purchased Power - Base Period Minus 1		Purchased Power - Base Period Minus 2	
Statistical Classification	Page Number	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased
RQ	326-327	$21,452,392	286,516				
LF	326-327	118,386,444	3,536,694				
IF	326-327	0	-				
SF	326-327	103,536,270	2,156,156				
LU	326-327	67,719,154	1,290,616				
IU	326-327	117,976	3,719				
OS	326-327	40,401	800				
EX	326-327	100,610	1,922				
NA	326-327	0	-				
AD	326-327	0	-				
TOTAL		$311,353,247	7,276,423	$ -	-	$ -	-
FERC Form 1		Sales for Resale - Base Period		Sales for Resale - Base Period Minus 1		Sales for Resale - Base Period Minus 2	
Statistical Classification	Page Number	Settlement Total	MWh Sold	Settlement Total	MWh Sold	Settlement Total	MWh Sold
RQ	310-311	$0	-				
LF	310-311	0	-				
IF	310-311	0	-				
SF	310-311	47,339,878	1,267,830				
LU	310-311	0	-				
IU	310-311	0	-				
OS	310-311	0	-				
EX	310-311	0	-				
NA	310-311	0	-				
AD	310-311	0	-				
TOTAL		$47,339,878	1,267,830	$ -	-	$ -	-
		Price Spread 2006					
	Average PP	48.02					
	Average SS	37.34					
	1/2 difference	5.34					
	Mid Point	42.68					
		12.52%					
		12.52%					

Draft Decision:

BPA will use 12.52% as the price spread in the ASC Forecast Model.

5.5.2. Input Errors in the ASC Appendix 1 and ASC Forecast Model

Statement of Issue:

Did NWE properly complete and enter correct values and modify the Appendix 1 Template and ASC Forecast Model?

Statement of Facts:

NWE made an error in completion of the Appendix 1 template which was not discovered by BPA staff until the final quality control review of the ASC Draft Report, Appendix 1 and ASC Forecast model. The error was caused by complexities unique to NWE and was a result of the accounting for conservation costs on the FERC Form 1.

When NWE recorded conservation costs in Account 930.2 – Miscellaneous General Expenses, they did not modify the ASC Appendix 1 Model that the account was functionalized using direct analysis. The result of this omission was that the production-related costs in Account 930.2 did not get included in the ASC Forecast model.

Summary of Parties' Positions:

No parties submitted comments on this issue.

Analysis of Positions:

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

> A direct analysis may be performed only if Table 1 indicates that a Utility may perform a direct analysis on the Account. The only exception to this requirement is for conservation-related costs. Because the FERC Form 1 does not contain a specific set of accounts for conservation-related costs, Utilities record those costs in a variety of FERC accounts.

Most exchanging IOUs record conservation costs in Account 908 – Customer Assistance Expenses (Major Only). The functionalization for Account 908 is direct analysis with an option for distribution. However, NWE records conservation costs in Account 930.2 – Miscellaneous General Expenses. The functionalization for Account 930.2 is distribution, with no optional functionalization. Because utilities can perform a direct analysis on any account containing conservation costs, BPA accepted NWE's direct analysis on Account 930.2.

Draft Decision:

BPA amended NWE's Appendix 1template to indicate that Account 930.2 was functionalized using direct analysis.

6. OTHER ISSUES

6.1. Generic Issue List

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

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

Statement of Issue:

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

Statement of Facts:

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

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

Summary of Parties' Positions:

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

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

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

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

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

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

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

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

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

<u>Analysis of Positions</u>:

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

The 2008 ASCM states "Functionalization of each Account included in a Utility's Average System Cost (ASC) shall be according to the functionalization prescribed in Table 1, *Functionalization and Escalation Codes*, beginning on page 18. Direct Analysis on an Account may be performed only if Table 1 states specifically that a Utility may perform a Direct Analysis on the Account with the exception of conservation costs. Utilities will be able to functionalize all conservation-related costs to Production, regardless of the Account in which they are recorded." *Id* at 16.

When utilities perform a direct analysis on an Account, they must submit sufficient documentation so that BPA can determine if the functionalization is reasonable. In addition, the 2008 ASCM states that "BPA will not allow Utilities to use a combination of Direct Analysis and a prescribed functionalization method for the same Account. The Utilities can develop and use a functionalization ratio or use a prescribed functionalization method if the Utility through Direct Analysis can justify how the ratio adequately reflects the functional nature of the costs included in any Account or cost item being functionalized by the ratio." *Id.* at 17.

BPA's review of the initial ASC filings revealed that most utilities either used the PTD or Labor ratio to functionalize a majority of Account 303 software. However, the functionalization methodology and rationale for the direct analysis was non existent, or weak and not consistent among utilities. Some of the statements included by utilities to support functionalization of a specific piece of software using the PTD ratio used terms like "supports all functions of the company"[8] or "supports all areas of the company."[9] These catchall phrases, if taken to the extreme, could be used to rationalize using the PTD ratio to functionalize the entire ASC filing using the PTD ratio. Such simple statements do not constitute a valid direct analysis.

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

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

However, a utility's ASC may include only allowable production and transmission costs determined in accordance with the 2008 ASCM. Using the PTD or LABOR ratio for all software costs could result in an incorrect functionalization of costs. For example, the costs of certain software packages are very large relative to others in Account 303, which would cause

[8] See, for example, Data Responses ASC-09 PA-BPA-12 and ASC-09-PS-BPA-6
[9] 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.

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.

Draft Decision:

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

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

System Categories

- ***Customer/Marketing*** – this category includes such applications as customer information systems for residential, commercial, and industrial customer billing, energy and demand management systems, meter reading, call center operations, and customer relationship management systems.
  - *Customer Information System (CIS)* – systems that manage the residential and small commercial customer information, bill calculation and presentation, and payment processes. Distribution - Accounts 901-910.
  - *Industrial Billing* – systems that manage the large industrial customers, bill calculation and presentation processes. Distribution - Accounts 901-910.
  - *Energy and Demand Management Systems* – systems and software that design, administer, manage, track, and report on the utility's portfolio of Demand-Side Management (DSM) and Energy Efficiency (EE) programs. Production.
  - *Call Center Operations* - these systems manage the operations of customer call centers including telephony and data management and employee scheduling and performance management. Distribution - Accounts 901-910.
  - *Customer Relationship Management (CRM) System* – systems that manage information about the utility's customers. Distribution - Accounts 901-910.
  - *Advanced Meter Infrastructure (AIM) System* – systems that measure, collect and analyze energy usage from advanced devices through various communication media on request or on a pre-defined schedule. It also includes the infrastructure (e.g., hardware, software,

communications, customer associated systems, etc.) and the meter data management system components. Distribution – Account 902.
- *Meter Reading System* – systems that manage the meter reading for residential and commercial customers. It includes meter route management and performs limited meter read validation. Distribution - Accounts 902.

➢ ***Employee Information*** – this category includes such applications as employee benefits, human resources, training, time entry, payroll, and compensation management systems.
- *Payroll System* – systems that calculate pay for employees and produces payments (checks or direct deposits). LABOR – Account 920.
- *Human Resources* – systems that maintain employee information required to pay employees and maintain individual employee personal and work-related information. LABOR – Account 920.
- *Training System* – systems that maintain information about all employee training requirements, schedules, certifications, courses, and update/recertification requirements. LABOR – Account 920.
- *Time Entry System* – systems that capture actual time and attendance information for employees. LABOR – Account 920.
- *Compensation Management System* – systems that optimize and automate the salary planning process and maintain information on salary history, company guidelines, employee performance and job aspirations. LABOR – Account 920.

➢ ***Facilities Management*** – this category includes such applications as generation operations and management, transmission operations and management, substation operations and management, geographic information systems, asset/facilities management, and computer-aid design systems.
- *Geographic Information System (GIS)* – systems that integrate hardware, software, and data for capturing, managing, analyzing, and displaying all forms of geographically referenced information. Distribution - Accounts 580-599.
- *Computer Aided Design (CAD)* – systems that use computers to aid in the design and particularly the drafting (technical drawing and engineering drawing) of a part or product, including entire buildings. It is both a visual (or drawing) and symbol-based method of communication whose conventions are particular to a specific technical field. Distribution - Accounts 580-599.

➢ ***Financial Information*** – this category includes such applications as accounts receivable, accounts payable, general ledger, treasury and cash management, debt management, operations and capital budget preparation and management, asset accounting, work order accounting, and cost accounting systems.
- *Enterprise Resource Planning (ERP) System* – systems that provide a common foundation for business accounting including common functions such as accounts payable, general ledger, and accounts receivable. Representative vendor solutions include: Lawson Enterprise Financial Management, Oracle B-Business Suite, PeopleSoft Enterprise Financial Management Solutions, and SAP ERP Financials. LABOR – Account 920.

- *Treasury and Cash Management* – systems that maintain information on the cash accounts, investments cash pooling, and banking operations. Representative vendor solutions include: Oracle Cash and Treasury Management Solution, SymPro LABOR – Account 920.
- *Debt Management* – systems that manage the debt owned by the utility including debt instruments, notes, bonds, commercial paper, and stocks. PTDG.
- *Budget Preparation* – systems that provide for the preparation of both the capital and operational budget. These systems are often incorporated in the ERP system (see above). LABOR – Account 920.
- *Asset Accounting* – systems that automate the continuing property records of the utility. PTDG.
- *Work Order Accounting* – systems that maintain an automated sub-ledger to the general ledger to account for work-in-progress accounting for both capital and operation and maintenance projects. PTDG.
- *Cost Accounting* – systems that provide a standard cost accounting capability for both capital projects and operations and maintenance activities. LABOR – Account 920.

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

- *Executive Information* – systems that facilitate and support the information and decision-making needs of senior executives by providing easy access to both internal and external information relevant to meeting the strategic goals of the utility. LABOR – Account 920.
- *Key Performance Indicators* – systems that capture both internal and external information related to key business indicators for senior management. LABOR – Account 920.
- *Business Intelligence* – systems that provide historical, current, and predictive information about the operations of the utility. LABOR – Account 920.

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

- *Risk Management* – systems used to integrate loss data from a variety of sources to develop a comprehensive view of operational risk exposure to the utility. LABOR – Account 920.
- *Market Simulation* – systems used to provide a model of transmission and security-constrained optimization of the system resources against spatially distributed loads. These systems are used to produce realistic projections of market clearing prices and asset utilization levels across the transmission grid. Transmission.
- *Transmission Rights and Access* – systems that maintain data on the utility's transmission line rights and access policies. Transmission.
- *Transmission Pricing and Billing* – systems that, similar to the *Customer Information System* above, maintain information on transmission system customers, bill calculation and presentation, and payment processes. Transmission.

- *Wholesale Billing and Settlement* – systems that, similar to the *Customer Information System* above, maintain information on wholesale customers, bill calculation and presentation, and payment processes. LABOR – Account 920.
- *Market Dispatch* - LABOR – Account 920.
- *Energy Trading and Tagging* – systems that provide trade processing, risk control and invoicing, credit risk to manage credit exposure, collateral management, and counterparty evaluation. Representative vendor solutions include: Triple Point Technology's Commodity XL, Allegro, and ADICA's EMCAS system. Production.

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

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

- *Materials Management* – systems that maintain information on products, price lists, inventory receipts, shipments, movements, and counts within the utility, as well as to and from suppliers. These systems are often incorporated in the ERP system (see above). PTD.
- *Purchasing* – systems that automate the acquisition of goods and services. These systems are often incorporated in the ERP system (see above). LABOR – Account 920.
- *Warehouse and Inventory Management* – systems that include the physical inventory, shipping, receiving, and picking of items, barcode labeling, and space management. These systems are often incorporated in the ERP system (see above). PTD – Account 163.
- *Fleet Management* – systems that provide for the management and maintenance of all vehicles and equipment used by the utility including scheduling maintenance and preventive maintenance. Distribution - Account 933.
- *Fuel Management* – systems that maintain information on fuel management for the utility's fleet operations. Distribution - Account 933.
- *Alternative Energy Supply* – systems that manage the availability of energy supply from alternative sources which may be outside the control of the utility. Production.

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

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

- *Supervisory Control And Data Acquisition (SCADA)* – systems that maintain the real-time, as-operated state of the electrical network, tracking remote control and local control operations, temporary network changes, and fault conditions. TD.
- *Energy Management (EMS)*– systems used to reduce energy losses, improve the utilization of the system, increase reliability, and predict electrical system performance as well as optimize energy usage to reduce cost. TD.
- *System Dispatch* – systems used to evaluate and optimize on an hour-ahead and day-ahead basis the dispatch of the utility's power plants to changing plant conditions, power markets, and contractual obligations. Production.

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

- *Plant Maintenance* – systems used to plan, manage, and evaluate the required major maintenance activities typically in generation facilities or other major facilities and substations. Production.
- *Work Order* – systems that manage longer-duration work, either capital or operations and maintenance frequently performed by multi-person crews. Distribution.
- *Service Order* – systems that manage the short-interval work of the utility typically performed by service crews. The system would include work scheduling, tracking, and order completion. Distribution.
- *Outage Management* – systems that prioritize restoration efforts based upon criteria such as locations of emergency facilities, size of outages, and duration of outages, extent of outages and number of customers impacted; calculate estimates of restoration times; provides information on crews needed and assisting in restoration; and predict the location of fuse or breaker that opened upon failure. Representative vendor solutions include: ABB, GE Energy, Intergraph, Oracle Utilities, and Trimble. Distribution.

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

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

Statement of Issue:

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

Statement of Facts:

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

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

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."

<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)

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." [10] 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.

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

552 also dealt more broadly with accounting for regulatory assets and liabilities for electric and gas utilities.[11]

Regulatory assets and liabilities are a subset of the larger issue of the difference between accounting for utilities that are subject to price regulation and Generally Accepted Accounting Principles (GAAP). The issue can be traced back to the Internal Revenue Act of 1954 which permitted use of accelerated depreciation for income tax purposes. In 1962, the Accounting Principles Board (precursor to FASB) issued Opinion No. 2, which dealt comprehensively with the issue of accounting for industries subject to price regulation, was prepared in response to questions surrounding the creation of investment tax credits by Congress. Opinion No. 2 stated that all companies are subject to GAAP, but that differences may arise, generally surrounding recognition of cost, for companies subject to price or rate regulation.[12]

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.

Draft 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 that are not included in the utility's jurisdictional rate base.

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

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

Statement of Issue:

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

[11] Ibid. 11-5
[12] Ibid.

Statement of Facts:

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

Summary of Parties' Positions:

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

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

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

Analysis of Positions:

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

Draft Decision:

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

6.1.4. Various Other Regulatory Assets and Liabilities

Statement of Issue:

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

Statement of Facts:

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

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

Summary of Parties' Positions:

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

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

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

rate base but not through the regulated working capital component of rate base calculation) for ratemaking purposes, the utility should further review the specific functional nature of the balance sheet account. If, however, the balance sheet account was either not included directly in rate base for ratemaking purposes or was included only via the regulated working capital calculation, the utility should functionalize the balance sheet account to DIST/Other.

Analysis of Positions:

The 2008 ASCM ROD states that "The Utility must describe the functional nature of the regulatory asset or liability, whether or not the asset or liability is included in rate base by its state commission(s), and the return or carrying costs allowed by the state commission(s). *Under no conditions would regulatory assets be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates."* 2008 ASCM ROD at 149 (emphasis added).

Regulatory assets and liabilities exist in the balance sheets of electric utilities only because of the effects of regulation. FERC defines them as "assets and liabilities that result from rate actions regulatory agencies." [13] 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.[14]

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.[15]

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

Regulatory assets and liabilities will eventually be moved from the balance sheet to the income statement through recognition of the revenue or expense. They are only recorded on the utility balance sheets because of regulation. BPA and its customers reviewed revenue and expense

[13] 6 *See* §11.03[2], G. Hahne and G. Aliff, *Public Utility Accounting*, pages 11-5 (Mathew Binder 2005).
[14] Ibid. 11-5
[15] Ibid.

accounts in detail during the 2008 ASCM consultation process and the 2008 ASCM has functionalization rules for those accounts. BPA will not change the functionalization of an income statement account as a result of a direct analysis on regulatory assets and liabilities.

Draft Decision:

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

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

Statement of Issue:

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

Statement of Facts:

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

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

Summary of Parties' Positions:

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

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

Analysis of Positions:

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

Draft Decision:

Utilities shall not adjust their purchase power and sales for resale for the effects of 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 NWE's February 25, 2009, response to BPA's Issue List stated that

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

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

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

The 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.

Analysis of Positions:

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 suggested that an independent third party should supply the natural gas forecast.

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

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

BPA agrees with the parties that a common gas forecast would be one reasonable approach. However, using the utility-supplied natural gas forecasts from the utilities' October 1, 2008, 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.

Draft Decision:

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 – Capacity Factors

Statement of Issue:

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

Statement of Facts:

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

Summary of Parties' Positions:

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

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

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

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

Resource Type	Capacity Factor
Combined Cycle CT	45% to 75%
Simple Cycle CT	1% to 30%

Wind	25% to 45%
Geothermal	greater than 90%

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

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

Overall BPA adjustments, including all changes made to NWE's Appendix 1 filing, decreased NWE's CY 2006 ASC by $2.24/MWh. The changes increased NWEs ASC FY 2009 ASC by $0.20/MWh, NorthWestern Energy's FY 2009 ASC, prior to any new resource additions, is $50.55/MWh.

8. BPA STATEMENT

This draft ASC determination is BPA's best estimate of NWE's FY 2009 ASC based on the information and data provided by NWE 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 submitted by NWE, can be viewed at BPA's REP website: http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

9. ADMINISTRATOR'S APPROVAL

I have examined NorthWestern Energy'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 NorthWestern Energy's ASC.