

FY 2010-2011

FINAL

AVERAGE SYSTEM COST REPORT

NORTHWESTERN ENERGY

July 2009



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FY 2010 – FY 2011

FINAL

AVERAGE SYSTEM COST REPORT

FOR

NorthWestern Energy

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

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

July 21, 2009

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1. FILING DATA

Utility: **NorthWestern Energy**
40 E. Broadway
Butte, MT 59701
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 (SNOPUD)

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

ASC Base Period: CY 2007

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

Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine NorthWestern Energy's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General information can be found at <http://www.bpa.gov/corporate/finance/ascm/index.cfm>.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would 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, both IOUs and COUs, 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 the most recent Annual Reports, including the most recent Cost of Service Analyses (COSA), for COUs. The submitted information includes the “Appendix 1,” the Excel based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by NWE on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

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

	October 15, 2008 As Filed	July 21, 2009 Final Report
Production Cost	\$337,095,343	\$342,080,537
Transmission Cost	\$31,980,992	\$30,083,720
(Less) NLSL Costs	\$0	\$0
Contract System Cost (CSC)	\$369,076,335	\$372,164,257
Total Retail Load (MWh)	5,863,531	5,863,531
(Less) NLSL	0	0
Total Retail Load (Net of NLSL)	5,863,531	5,863,531
Distribution Losses	257,995	257,995
Contract System Load (CSL)	6,121,526	6,121,526
CY 2007 Base Period ASC (CSC/CSL)	\$60.29/MWh	\$60.80/MWh

2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December, 31, 2007) to the end of the Exchange Period (September, 30, 2011). When a major new resource addition is projected to come on-line

prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

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

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase or decrease of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including in response to comments submitted by the utility and/or intervenors during the ASC Review Process. NWE did not submit information on new resources.

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

As-Filed FY 2010-2011 Exchange Period ASC	
Resource	NA.
Expected On-Line Date	
Delta*	

Final Report FY 2010-2011 Exchange Period ASC	
Resource	NA.
Expected On-Line Date	
Delta*	

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

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

As-Filed FY 2010-2011 Exchange Period ASC	
Resource	NA.
Expected On-Line Date	
Delta*	

Final Report FY 2010-2011 Exchange Period ASC	
Resource	NA.
Expected On-Line Date	
Delta*	

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

2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, and adjusted by BPA for this Final ASC 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 in Table 2.2.2 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 2010-2011 ASC (\$/MWh)
Prior to the New Resource Additions**

Date	October 15, 2008 As-Filed	July 21, 2009 Final Report
FY 2010- 2011	55.30	57.57

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 Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to BPA at the average system cost ASC of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(1) of the Act. 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 authority to determine ASC on the basis of a methodology established in a public consultation proceeding. 16 U.S.C. § 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. § 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. *See* 48 Fed. Reg. 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 Fed. Reg. 39,293 (Oct. 5, 1984). In the late 1980s and mid-1990s, BPA and exchanging utilities executed a number of termination agreements that provided for payments to each utility through the

remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings. Subsequent REP Settlement Agreements with BPA's investor-owned utility customers were in effect from approximately 2001 through 2007, but were terminated following a judicial decision issued on May 3, 2007. *See generally, Portland General Elec. Co. v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007).

In 2007, BPA began administrative efforts to resume the full implementation of the REP, including the development of new RPSAs and a consultation proceeding to revise the 1984 ASC Methodology. As with the 1981 and 1984 ASC Methodologies, the 2008 ASCM was developed in a consultation proceeding with interested parties through, in part, a series of working group meetings conducted by BPA Staff. The goal of the consultation process was to develop an administratively feasible ASC Methodology that would be technically sound and comport with the Northwest Power Act. The ASCM is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission). On October 10, 2008, the Commission granted interim approval to BPA's 2008 ASCM. *See Sales of Elec. Power to the Bonneville Power Administration, Revisions to Average System Cost Methodology*, 73 Fed. Reg. 60,105 (Oct. 10, 2008).

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. ASC Review Process - FY 2010-2011

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

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

To determine a utility's Exchange Period ASC for FY 2010-2011 (October 1, 2009, through September 30, 2011), the Base Period (CY 2007) ASC is first calculated using the Appendix 1. BPA then uses the ASC Forecast Model to escalate the Base Period ASC forward to the mid-point of the effective Exchange Period. The Base Period and Exchange Period ASC results are reported herein.

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

The Exchanging utilities' October 15, 2008, ASC filings began the formal review and comment processes, referred to as the Review Period, to establish the utilities' respective ASCs. For the

Final ASC 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 October 10, 2008. The preliminary review resulted in the publication of the Draft ASC Reports. The utility's comments on this Draft ASC Report are noted and addressed herein. In addition, parties had a full and complete opportunity to intervene in BPA's ASC Review Processes and to submit comments on the utilities' ASC filings and Draft ASC Reports.

The Review Processes for the FY 2010-2011 ASCs are complete. The final ASC determinations and supporting justifications are published in the respective Final ASC Report for each participating utility and can be reviewed at <http://www.bpa.gov/corporate/finance/ascm/fy10-asc-final-reports.cfm>.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision, 2008 Average System Cost Methodology, June 2008*, entitled *2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power and Conservation Act*.

3.3. Explanation of Schedules

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

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

3.3.1. Schedule 1 – Plant Investment/Rate Base

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

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

The resulting 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 Production, Transmission, and/or Distribution/Other components of Total Rate Base

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 in 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.

When the Net Production and Transmission Plant-in-Service are multiplied by the Rate of Return as determined in Schedule 2, the result is the utility's return on investment.

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 certain 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. 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.

By law, NLSLs and the associated costs to serve them are not included in utilities’ ASCs. *See* 16 U.S.C. § 839c(c)(7)(A).

3.3.8. 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).

Contract System Cost:

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.

Contract System Load (MWh):

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.

3.3.9. 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.

3.3.10. Purchased Power and Sales for Resale

Purchased Power is an Account on 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. Please 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.

3.3.11. 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 ASC data forward to the mid-point of the Exchange Period, which in this case is FY 2010-2011. BPA used Global Insight's forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. For the Final ASC Reports, the escalators were updated to be consistent with the escalators used in BPA's WP-10 Wholesale Power Rate Adjustment Proceeding (WP-10 Final Rate Proposal). 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. *See also* 18 CFR § 301.5(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 mid-point of the FY 2010-2011 Exchange Period (October 1, 2010) to calculate Exchange Period ASCs. *See* 18 CFR § 301.5(a). 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. See 18 CFR § 301.5(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. See 18 CFR § 301.5(c). These additions include new production or new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments.

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

The forecast of the major resource costs to be included in the utility's Exchange Period ASC is reviewed and determined during the Review Period. When calculating the utility's Exchange Period ASC, the costs of all resources included prior to the start of the Exchange Period are projected forward to the mid-point of the Exchange Period. The costs of 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. To calculate the cost of serving load growth not served by new resource additions, BPA uses the method outlined in the 2008 ASCM, Section IV, *Rules for Determining Exchange*, Subsection D. See 18 CFR § 301.5(d).

4. REVIEW OF THE ASC FILING

Pursuant to Section III, Subsection C of 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. See 18

CFR § 301.4(c)(1). 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 BPA adopting a modified or different interpretation of the methodology in future ASC reviews.

On April 13, 2009, BPA published a Draft ASC Report for NWE. NWE and each intervenor had the opportunity to comment on the Draft ASC Report. All comments have been reviewed and addressed in reaching a final decision on each issue.

As noted in Section 1 above, if NWE or any intervenor failed to comment on a specific issue outlined in the Draft ASC Report, the utility or intervenor waives the right to subsequent appeal of that issue. To the extent any party argued it should not be required to raise issues in its comments on BPA's Draft ASC Reports in order to preserve such issues for appeal, BPA disagrees. If parties did not raise issues in their comments on BPA's Draft ASC Reports, BPA would not know whether the parties agreed or disagreed with BPA's draft decisions. Because BPA would not know the parties' arguments, BPA would be unable to consider and possibly adopt such arguments in determining a utility's ASC.

4.1. Identification and Analysis of Issues from BPA Issue List

During the ASC review process, BPA raised a number of issues regarding NWE's ASC. NWE responded to these issues during the ASC review process and in comments on the Draft ASC Report. No other party raised or commented on NWE's responses. Each issue pertains to the October 15, 2008, filing unless otherwise noted.

Although a utility's State, county or municipal regulatory bodies or FERC may allow a particular functionalization to a specific account, BPA is not required to follow this treatment when calculating ASCs under the 2008 ASCM. Rather, BPA is tasked with making an independent determination of the appropriateness of inclusion or exclusion of particular costs, the reasonableness of the costs included in Contract System Costs, the appropriateness of Contract System Loads, and the functionalization method used in the calculation of any cost, in conformance with the 2008 ASCM. *See* 2008 ASCM, Section III.C; 18 CFR § 301.4(c)(1).

4.2. SCHEDULE 1: Plant Investment/Rate Base:

4.2.1. Account 182.3 Other Regulatory Assets: Unbilled Competitive Transition Costs – Qualifying Facilities

Statement of Issue:

Has NWE properly calculated and appropriately functionalized its Unbilled Competitive Transition Costs – Qualifying Facilities (CTC QF) in accordance with the requirements of the functionalization rules of the 2008 ASCM? Does the documentation submitted with NWE’s ASC filing constitute a valid Direct Analysis? Should the costs associated with Unbilled CTC QF be functionalized to Production?

Statement of Facts:

NWE functionalized Unbilled CTC QF in Account 182.3 to Production.

NWE’s Response to BPA Data Request No. 8, filed January 30, 2009, states: “Unbilled CTC QF: Out of market QF costs recovered from customers.” NWE’s Response to BPA Data Request No. 14, filed January 30, 2009, states: “Unbilled CTC QF: relates to supply costs, directly assigned to Production.”

In response to a BPA Data Request 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. *Id.* In NWE Comments on BPA Draft ASC Report, pg. 1, filed May 6, 2009, NWE stated that they agreed with BPA’s decision regarding the functionalization of Unbilled CTC QF.

Parties’ Positions:

NWE agrees with BPA’s decision to functionalize Unbilled CTC QF in Account 182.3 to Distribution/Other.

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/Other. *See* 18 CFR PT 301, Table 1.

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 demonstrated that NWE did not receive a return on the Unbilled CTC QF costs. As a result, under the 2008 ASCM, Unbilled CTC QF costs must be functionalized to Distribution/Other. In its Comments on the Draft ASC Report, NWE agreed with BPA’s decision. See NWE’s Comments on BPA ASC Report, pg.1, filed May 6, 2009.

Decision:

The documentation provided by NWE in response to BPA discovery and Issue Lists showed that Unbilled CTC QF was not included in NWE’s retail rate base, and therefore, BPA will functionalize Unbilled CTC QF to Distribution/Other.

**Table 4.2.2: Account 182.3 Other Regulatory Assets:
Unbilled Competitive Transition Costs – Qualifying Facilities (\$)**

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	(366,841)	(366,841)	0	0
BPA Adjusted	(366,841)	0	0	(366,841)

4.2.2. 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 the documentation NWE 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 functionalized Basin Creek in Account 182.3 to Production.

For support, NWE stated that “Basin Creek[] Electric Energy supply costs provided from the Basin Creek generating facility.” NWE’s Response to BPA Data Request No. 8, filed January 30, 2009. NWE also noted that in a response to a BPA data request that Basin Creek “[r]elates to supply costs, directly assigned to production.” NWE’s Response to BPA Data Request No. 14, filed January 30, 2009.

In response to a BPA Data Request asking if the Basin Creek 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.” *Id.*

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

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.

Id.

Because the available evidence indicated that Basin Creek was not included in NWE's rate base, BPA proposed in the Draft ASC Report to functionalize this item to Distribution/Other. In its Comments on the Draft ASC Report, NWE agreed with BPA's decision. *See* NWE Comments on BPA Draft ASC Report, pg. 1, filed May 6, 2009.

Parties' Positions:

NWE agrees with BPA's decision to functionalize Basin Creek to Distribution/Other.

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/Other. *See* 18 CFR PT 301, Table 1.

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 demonstrated that Basin Creek was not included in NWE's retail rate base. As a result, under the 2008 ASCM, Basin Creek must be functionalized to Distribution/Other. In its Comments on the Draft ASC Report, NWE agreed with BPA's decision. *See* NWE's Comments on BPA ASC Report, pg.1, filed May 6, 2009.

Decision:

The documentation provided by NWE in response to BPA discovery and Issue Lists showed that Basin Creek was not included in NWE's retail rate base, and therefore, BPA will functionalize Basin Creek to Distribution/Other.

**Table 4.2.3: Account 182.2 Other Regulatory Assets:
Basin Creek (\$)**

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	1,625,766	1,625,766	0	0
BPA Adjusted	1,625,766	0	0	1,625,766

4.2.3. 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 the documentation NWE 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 functionalized Compensated Absences - Contra in Account 182.3 using the Labor Ratio. To support this functionalization, NWE provided the following statements: first, in NWE’s Response to BPA Data Request No. 8, filed January 30, 2009, NWE 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

Second, in NWE’s Response to BPA Data Request No. 14, filed January 30, 2009, NWE stated that “Compensated Absences: Relates to vacation accruals and employee benefits that encompass all functions, should be allocated based on labor” and that “FAS 106/FAS 112/Pension: Relates to employee benefits that encompass all functions, should be allocated based on labor.” *Id.*

In response to a BPA Data Request asking if the Compensated Absences – Contra was included in NWE’s jurisdictional rate base, NWE replied that “[t]he final result of NWE’s filing is a stipulation in which the Account 182.3 amounts are included as filed.” *Id.*

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.

Id.

Moreover, in 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.” *Id.*

Because the available evidence indicated that this item was not included in NWE’s rate base, BPA proposed in the Draft ASC Report to functionalize it to Distribution/Other. In its Comments on the Draft ASC Report, NWE agreed with BPA’s decision. *See* NWE Comments on BPA Draft ASC Report, pg. 1, filed May 6, 2009.

Parties’ Positions:

NWE agrees with BPA’s decision to functionalize Compensated Absences - Contra to Distribution/Other.

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/Other. *See* 18 CFR Pt. 301, Table 1.

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 demonstrated that Compensated Absences - Contra was not included in NWE’s retail rate base. As a result, under the 2008 ASCM, Compensated Absences - Contra must be functionalized to Distribution/Other. In its Comments on the Draft ASC Report, NWE agreed with BPA’s decision. *See* NWE’s Comments on BPA ASC Report, pg.1, filed May 6, 2009.

Decision:

The documentation provided by NWE in response to BPA discovery and Issue Lists showed that Compensated Absences - Contra was not included in NWE’s jurisdictional rate base, and therefore, BPA will functionalize Compensated Absences - Contra to Distribution/Other.

**Table 4.2.4: Account 182.3 Other Regulatory Assets:
Compensated Absences - Contra (\$)**

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	(152,667)	(2,995)	(27,189)	(122,183)
BPA Adjusted	(152,667)	0	0	(152,667)

4.2.4. 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 the documentation NWE 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 functionalized Compensated Absences in Account 182.3 using the Labor ratio. To support this functionalization, NWE provided the following statements: first, in NWE’s Response to BPA Data Request No. 8, filed January 30, 2009, NWE 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

Second, in NWE’s Response to BPA Data Request No. 14, filed January 30, 2009, NWE stated “Compensated Absences: Relates to vacation accruals and employee benefits that encompass all functions[. . .] should be allocated based on labor” and that “FAS 106/FAS 112/Pension: Relates to employee benefits that encompass all functions, should be allocated based on labor.”

In response to a BPA Data Request asking if the Compensated Absences were included in NWE’s jurisdictional rate base, NWE replied “[t]he 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.

Id.

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.” *Id.*

Because the available evidence indicated that this item was not included in NWE’s rate base, BPA proposed in the Draft ASC Report to functionalize Compensated Absences to Distribution/Other. In its Comments on the Draft ASC Report, NWE agreed with BPA’s decision. *See* NWE Comments on BPA Draft ASC Report, pg. 1, filed May 6, 2009.

Parties’ Positions:

NWE agrees with BPA’s decision to functionalize Compensated Absences to Distribution/Other.

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/Other. *See* 18 CFR Pt. 301, Table 1.

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 demonstrated that Compensated Absences were not included in NWE’s retail rate base. As a result, under the 2008 ASCM, Compensated Absences must be functionalized to Distribution/Other. In its Comments on the Draft ASC Report, NWE agreed with BPA’s decision. *See* NWE’s Comments on BPA ASC Report, pg.1, filed May 6, 2009.

Decision:

The documentation provided by NWE in response to BPA discovery and Issue Lists showed that Compensated Absences was not included in NWE’s jurisdictional rate base, and therefore, BPA will functionalize Compensated Absences to Distribution/Other.

**Table 4.2.5: Account 182.3 Other Regulatory Assets:
Compensated Absences (\$)**

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	3,772,949	74,017	671,937	3,026,995
BPA Adjusted	3,772,949	0	0	3,772,949

4.2.5. Account 182.3 Other Regulatory Assets – FAS 112

Statement of Issue:

Has NWE properly calculated and appropriately functionalized its Other Regulatory Assets: FAS 112, in accordance with the requirements of the functionalization rules of the 2008 ASC Methodology? Does the documentation NWE submitted with its ASC filing constitute a valid Direct Analysis? Should the costs associated with FAS 112 be functionalized using the Labor ratio?

Statement of Facts:

NWE functionalized FAS 112 in Account 182.3 using the Labor ratio. To support this functionalization, NWE provided the following statements: first, in NWE’s Response to BPA Data Request No. 8, filed January 30, 2009, NWE 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

Second, in NWE’s Response to BPA Data Request No. 14, filed January 30, 2009, NWE stated that “FAS 106/FAS 112/Pension: Relates to employee benefits that encompass all functions, should be allocated based on labor.”

In response to a BPA Data Request asking if the FAS 112 costs were included in NWE’s jurisdictional rate base, NWE replied “[t]he final result of NWE’s filing is a stipulation in which the Account 182.3 amounts are included as filed.” *Id.*

However, the next document following the above statement indicated that FAS 112 costs are not in NWE’s jurisdictional rate base. The “Comments” column on the table stated that “FAS 112 - costs are recovered on a funding basis. This reflects accruals in excess of funding.” *Id.* In the same document, under the column entitled “Rate Base” where other items were listed as “yes” or “no”, NWE stated that the FAS 112 were “Offset by benefit liability.” *Id.*

Because the available evidence indicated that this item was not included in NWE’s rate base, BPA proposed in the Draft ASC Report to functionalize FAS 112 costs to Distribution/Other. In

its Comments on the Draft ASC Report, NWE agreed with BPA’s decision. See NWE Comments on BPA Draft ASC Report, pg. 2, filed May 6, 2009.

Parties’ Positions:

NWE agrees with BPA’s decision to functionalize FAS 112 to Distribution/Other.

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/Other. See 18 CFR Pt 301, Table 1.

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 showed that FAS 112 costs were not included in NWE’s retail rate base. As a result, under the 2008 ASCM, FAS 112 costs must be functionalized to Distribution/Other. In its Comments on the Draft ASC Report, NWE agreed with BPA’s decision. See NWE’s Comments on BPA ASC Report, pg. 2, filed May 6, 2009.

Decision:

The documentation provided by NWE in response to BPA discovery and Issue Lists showed that FAS 112 was not included in NWE’s jurisdictional rate base, and therefore, BPA will functionalize FAS 112 to Distribution/Other.

**Table 4.2.6: Account 182.3 Other Regulatory Assets:
FAS 112 (\$)**

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	2,879,787	56,495	512,871	2,310,421
BPA Adjusted	2,879,787	0	0	2,879,787

4.2.6. Account 182.3 Other Regulatory Assets - Pension

Statement of Issue:

Has NWE properly calculated and appropriately functionalized its Other Regulatory Assets: Pension in accordance with the requirements of the functionalization rules of the 2008 ASC

Methodology? Does the documentation NWE submitted with its ASC filing constitute a valid Direct Analysis? Should the costs associated with Pension be functionalized using the Labor ratio?

Statement of Facts:

NWE functionalized Pension Plan in Account 182.3 using the Labor ratio. To support this functionalization, NWE provided the following statements: first, in NWE's Response to BPA Data Request No. 8, filed January 30, 2009, NWE 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

Second, in NWE's Response to BPA Data Request No. 14, filed January 30, 2009, NWE stated that "FAS 106/FAS 112/Pension: Relates to employee benefits that encompass all functions, should be allocated based on labor."

In response to a BPA Data Request asking if Pension Plan was included in NWE's jurisdictional rate base, NWE replied "[t]he final result of NWE's filing is a stipulation in which the Account 182.3 amounts are included as filed." *Id.*

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 that "[p]ension costs are recovered on a modified funding basis. This reflects the difference between FAS 71 accruals and that modified funding." *Id.*

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 PI". *Id.*

Because the available evidence indicated that this item was not included in NWE's rate base, BPA proposed in the Draft ASC Report to functionalize Pension Plan costs to Distribution/Other. In its Comments on the Draft ASC Report, NWE agreed with BPA's decision. *See* NWE Comments on BPA Draft ASC Report, pg. 2, filed May 6, 2009. In addition, NWE noted that

However, NWE would note that there's an amount of \$12,554,191 identified as "Pension Plan Requirement" included in the Other Deferred Credits section on the "Regulatory Assets" tab that NWE believes should also be functionalized to Distribution. This is a corresponding liability (Account 253) that NWE believes follows BPA's discussion and decision in Generic issue 6.1.3. In addition, NWE would propose that the amount of \$11,009,977 identified as "Pension Differential" included in "Regulatory Debits" and reflected on Schedule 3B also be functionalized to Distribution to maintain consistent treatment of pension-related items.

Parties' Positions:

NWE agrees with BPA's decision to functionalize Pension in Account 182.3 to Distribution/Other. NWE requests that Pension Plan Requirement included in the Other Deferred Credits section on the "Regulatory Assets" tab also be functionalized to Distribution/Other. NWE also requests that "Pension Differential," which is included in "Regulatory Debits" and reflected on Schedule 3B, be functionalized to Distribution/Other to maintain consistent treatment of pension-related items.

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/Other. *See* 18 CFR Pt 301, Table 1.

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 showed that Pension Plan costs were not included in NWE's retail rate base. As a result, under the 2008 ASCM, Pension Plan costs must be functionalized to Distribution/Other. In its Comments on the Draft ASC Report, NWE agreed with BPA's decision. *See* NWE's Comments on BPA ASC Report, pg. 2, filed May 6, 2009.

In response to NWE's request, BPA agrees that the Pension Plan Requirement and the Pension Differential included in Account 253 Other Deferred Credits should be functionalized to Distribution/Other based on BPA's decision in Generic Issue 6.1.3 below, which provides that corresponding assets and liabilities have a common functionalization.

Decision:

Because the documentation provided by NWE did not show that the cost associated with Pension Plan was included in NWE's jurisdictional rate base, BPA will functionalize Pension Plan to Distribution/Other. BPA will also functionalize the Pension Plan Requirement and the Pension Differential in Account 253 to Distribution/Other.

**Table 4.2.7.1: Account 182.3 Other Regulatory Assets:
Pension (\$)**

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	27,638,427	542,203	4,922,221	22,174,004
BPA Adjusted	27,638,427	0	0	27,638,427

**Table 4.2.7.2: Account 253 Other Deferred Credits:
Pension (\$)**

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	12,554,191	246,284	2,234,285	10,073,622
BPA Adjusted	12,554,191	0	0	12,554,191

4.2.7. 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 the documentation NWE submitted with its ASC filing constitute a valid Direct Analysis? Should FAS 106 be functionalized using the Labor ratio?

Statement of Facts:

NWE functionalized FAS 106 costs in Account 182.3 using the Labor ratio. To support this functionalization, NWE provided the following statements: first, in NWE’s Response to BPA Data Request No. 8, filed January 30, 2009, NWE 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

Second, in NWE’s Response to BPA Data Request No. 14, filed January 30, 2009, NWE stated that “FAS 106/FAS 112/Pension: Relates to employee benefits that encompass all functions, should be allocated based on labor.”

In response to a BPA Data Request asking if the FAS 106 was included in NWE’s jurisdictional rate base, NWE replied “[t]he final result of NWE’s filing is a stipulation in which the Account 182.3 amounts are included as filed.” *Id.*

However, the next document following the above statement indicated that FAS 106 costs are not included 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.

Id.

On the same document, under the column entitled “Rate Base” where other items were listed as “yes” or “no”, NWE stated that FAS 106 costs were “Offset by benefit liability.” *Id.*

Because the available evidence indicated that this item was not included in NWE’s rate base, BPA proposed in the Draft ASC Report to functionalize FAS 106 costs to Distribution/Other. In its Comments on the Draft ASC Report, NWE agreed with BPA’s decision. *See* NWE Comments on BPA Draft ASC Report, pg. 2, filed May 6, 2009. In addition, though, NWE noted that

. . . there’s an amount of \$186,846 identified as “FAS 106 Transitional Obligation” included in the Other Deferred Credits section on the “Regulatory Assets” tab that NWE believes should also be functionalized to Distribution. This is a corresponding liability (Account 253) that NWE believes follows BPA’s discussion and decision in Generic issue 6.1.3.

Parties’ Positions:

NWE agrees with BPA’s decision to functionalize FAS 106 to Distribution/Other. NWE also requests that “FAS 106 Transitional Obligation” included in the Other Deferred Credits section on the “Regulatory Assets” tab be functionalized to Distribution/Other.

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/Other. *See* 18 CFR Pt 301, Table 1.

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 demonstrated that FAS 106 costs were not included in NWE’s retail rate base. As a result, under the 2008 ASCM, FAS 106 costs must be functionalized to Distribution/Other. In its Comments on the Draft ASC Report, NWE agreed with BPA’s decision. *See* NWE’s Comments on BPA ASC Report, pg.1, filed May 6, 2009.

With respect to NWE’s other comment, BPA agrees that the FAS 106 Transitional Obligation included in Account 253 Other Deferred Credits should be functionalized to Distribution/Other based on BPA’s decision in Generic Issue 6.1.3 below, which requires that corresponding assets and liabilities have a common functionalization.

Decision:

The documentation provided by NWE in response to BPA discovery and Issue Lists showed that FAS 106 costs were not included in NWE’s jurisdictional rate base, and therefore, BPA will functionalize FAS 106 to Distribution/Other. BPA will also functionalize FAS 106 Transitional Obligation in Account 253 to Distribution/Other.

**Table 4.2.8.1: Account 182.3 Other Regulatory Assets:
FAS 106 (\$)**

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	14,558,336	285,601	2,592,743	11,679,992
BPA Adjusted	14,558,336	0	0	14,558,336

**Table 4.2.8.2: Account 253 Other Deferred Credits:
FAS 106 Transitional Obligation (\$)**

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	186,846	3,665	149,927	33,253
BPA Adjusted	186,846	0	0	186,846

4.2.8. 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 the documentation NWE 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:

Section VIII of the 2008 ASCM requires a utility to functionalize its Accounts in accordance with Table 1 of the ASCM. *See* 18 CFR Pt 301, Table 1. Table 1 provides two alternatives for the functionalization of items in Account 303. First, the utility may perform a Direct Analysis. *Id.* Second, if the utility does not perform such analysis, the default functionalization is Distribution/Other. *Id.*

In its initial filing, NWE functionalized the software in Account 303.1 using the PTD ratio. BPA, however, was unable to substantiate NWE’s use of 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.

BPA noticed that the Direct Analyses performed by the utilities participating in the FY 2010-11 ASC Review Processes 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 Power functionalized such software using the PTD ratio. In all instances, the utilities' proposed functionalization was not supported with documentation or other evidence. To address this issue, BPA proposed in Section 6.1 of the Draft ASC Reports to adopt a generic functionalization framework for software programs in Account 303. This generic framework would be used to functionalize items in Account 303 if the utility's Direct Analysis was insufficient. NWE supported BPA's decision to functionalize software assets among the utilities in this manner. *See* NWE Response to BPA Issue List, pg. 2, Filed February 11, 2009.

In NWE's Draft ASC Report, BPA functionalized Common Plant Intangibles to Distribution/Other. BPA proposed this functionalization because NWE had not supplied BPA with sufficient information to determine the appropriate functionalization of the items in Account 303. NWE subsequently provided BPA with additional information about the use and function of its software assets in its Comments on the Draft ASC Report. *See* NWE Comments on BPA ASC Report, pg. 3, Filed May 6, 2009. To assist BPA's review, NWE provided BPA with a common plant spreadsheet with individual software detail following BPA's template. *Id.* The new data supplied by NWE allowed BPA to better understand the functions that NWE's software assets supported.

Parties' Positions:

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

Analysis of Positions:

Section VIII.B, Table 1 of the 2008 ASCM, provides that functionalization of Account 303 is Direct Analysis with a default to Distribution/Other. *See* 18 CFR Pt 301, Table 1. When utilities perform a Direct Analysis on an Account, they must submit sufficient documentation so that BPA can determine if the proposed functionalization is reasonable. *See* 2008 ASCM, Section VIII.A.2; 18 CFR § 301.9(c)(2). Failure to submit the necessary documentation will "result in the entire account being functionalized to Distribution/Other . . . as appropriate." *Id.*

In addition, the 2008 ASCM provides 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.

2008 ASCM, Section VIII.B.2; 18 CFR § 301.9(d)(2); *see also* 2008 ASCM ROD, at 29.

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 used by the utilities was not consistent. In most instances, the utilities supported their use of the PTD ratio by claiming the software "supports all functions of the company"¹ or "supports all areas of the company."² These catchall phrases, if allowed to support a Direct Analysis, could be used to functionalize the utility's entire ASC filing with the PTD ratio. Such simple statements do not constitute a valid Direct Analysis. Consequently, under the ASCM, BPA has the authority to functionalize all of the items in Account 303 to Distribution/Other.

Nonetheless, because this ASC Report was developed in conjunction with the first set of ASCs under the 2008 ASCM, BPA proposed to allow software costs into ASC based on the generic function of the software in the utility industry. This construct is described in more detail in the Generic Issue discussion under Section 6.1.1. In general, BPA proposed to first look at the Direct Analysis performed by the utility. If the documentation supplied by the utility supported its proposed functionalization, BPA would follow the utility's treatment. However, if the utility could not support its proposed functionalization, BPA would then functionalize the costs to Distribution/Other unless BPA could determine the function that the software supported. For this, BPA looked to common utility practices and uses of the pertinent software program. If BPA could determine that the particular software program supported resource-related functions in the utility industry, the software system would be functionalized accordingly. BPA developed this approach for Account 303 because it ensured that software costs would 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 the instant case, NWE agreed with BPA's decision to use generic software categories for functionalizing the items in Account 303. *See* NWE Comments on BPA ASC Report, pg. 3, Filed May 6, 2009. In addition, NWE supplied additional information about the use and function of the software assets in Account 303 to BPA. After reviewing this new information, BPA was able to functionalize NWE's Common Plant Intangibles using BPA's generic software framework. The results of BPA's analysis are provided in Tables 4.2.8.1 – 4.2.8.3 below.

Decision:

BPA will functionalize Account 303.1 using the general software functionalization framework discussed in Section 6.1 of this report.

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

² *See, for example*, Data Response ASC-09-PS-BPA-12, and Excel file E302, 303, E399, Common 2006 filed.xls, DATA for ASC tab, column W.

**Table 4.2.9.1: Account 303.1 Common Plant Intangible –
Plant in Service: Software: (\$)**

	Total	Production	Transmission	Dist/Other
As-Filed	6,176,033	13,135	1,466,553	4,696,345
BPA Adjusted	6,176,033	134,287	1,560,002	4,481,744

**Table 4.2.9.2: Account 303.1 Common Plant Intangible –
Accumulated Depreciation: Software: (\$)**

	Total	Production	Transmission	Dist/Other
As-Filed	(2,551,201)	(5,426)	(605,805)	(1,939,970)
BPA Adjusted	(2,551,201)	(14,449)	(656,727)	(1,880,025)

**Table 4.2.9.3: Account 303.1 Common Plant Intangible –
Amortization Expense: Software: (\$)**

	Total	Production	Transmission	Dist/Other
As-Filed	966,930	2,057	229,606	735,268
BPA Adjusted	966,930	6,735	271,054	689,141

4.2.9. 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 the documentation NWE 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:

This issue is similar to the issue discussed above in section 4.2.8. 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. BPA then evaluated the NWE’s software assets using BPA’s generic software framework discussed in section 4.2.8. As a result of this review, BPA changed the functionalization of Account 303.2, Common Plant Intangible Software from PTD to Labor in the Draft ASC Report.

NWE supports BPA’s decision to functionalize Account 303.2, Common Plant Intangible Software with the Labor ratio. *See* NWE Comments on BPA ASC Report, pg. 3, Filed May 6, 2009.

Parties' Positions:

NWE supports BPA's decision to change the functionalization of Account 303.2, Common Plant Intangible Software from PTD to Labor.

Analysis of Positions:

Account 303.2, Common Plant Intangible Software is composed of primarily costs associated with Enterprise Resource Planning (ERP). Under BPA's software cost functionalization framework, ERP systems are functionalized using the Labor ratio because the primary benefit of these programs 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. Thus, the appropriate functionalization of this item is to Labor.

NWE supports BPA's decision to functionalize Account 303.2, Common Plant Intangible Software with the Labor ratio. See NWE Comments on BPA ASC Report, pg. 3, Filed May 6, 2009.

Decision:

BPA will functionalize Account 303.2 using the Labor ratio.

Table 4.2.10.1: Account 303.2 Common Plant Intangible - Plant in Service: Software: (\$)

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
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

Table 4.2.10.2: Account 303.2 Common Plant Intangible – Accumulated Depreciation: Software: (\$)

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	8,662,971	18,425	2,057,098	6,587,448
BPA Adjusted	8,662,971	155,012	1,534,918	6,933,042

Table 4.2.10.3: Account 303.2 Common Plant Intangible – Amortization Expense: Software: (\$)

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	1,416,629	3,013	336,391	1,077,225
BPA Adjusted	1,416,629	25,455	252,057	1,139,117

4.2.10. 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 the documentation NWE 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.

In the Draft ASC Report, BPA changed the functionalization of NWE's Common Plant Accounts 389 through 398 to match the functionalization of the General Plant Accounts 389 through 391 in Table 1 of the ASCM. NWE agreed with BPA's changes in its Comments on the Draft ASC Report. *See* NWE Comments on BPA Draft ASC Report, pg. 3, filed May 6, 2009. In addition, NWE noted that it was "providing depreciation/amortization expense detail for each of the individual accounts (389-398) and proposes that BPA replace the allocation it performed to functionalize the expense with the functionalization presented in the spreadsheet." *Id.*

Parties' Positions:

Although NWE functionalized Common Plant Accounts 389 through 398 using the PTD ratio, NWE agreed with BPA's decision to change these accounts to match the functionalization of General Plant Accounts 389-398 in Table 1 of the ASCM.

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. *See* 18 CFR Pt 301, Table 1.

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.

See 18 CFR § 301.9(a).

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.

See 18 CFR § 301.9(c)(2).

NWE did not provide support for its use of the PTD ratio to functionalize Common 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 General Plant 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 utility portion.

BPA changed the functionalization of NWE's Common Plant Accounts 389 through 398 to match the functionalization of the General Plant Accounts 389 through 391 in Table 1 of the ASCM. NWE agreed with BPA's changes in its Comments on the Draft ASC Report. *See* NWE Comments on BPA Draft ASC Report, pg. 3, filed May 6, 2009.

In addition, NWE noted that it was "providing depreciation/amortization expense detail for each of the individual accounts (389-398) and proposes that BPA replace the allocation it performed to functionalize the expense with the functionalization presented in the spreadsheet." *Id.* BPA reviewed the additional information supplied by NWE with their comments to BPA's Draft ASC Report and accepts the revisions suggested by NWE to the accumulated depreciation and amortization expense tables.

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 General Plant Accounts 389 through 398 contained on Table 1 of the 2008 ASCM. BPA accepts the revisions suggested by NWE to the accumulated depreciation and amortization expense tables

NWE As-Filed Common Plant					
Common Plant	Funct.	Plant	Production	Transmission	Distribution
Account No. 389	PTD	1,996,471	4,110	463,212	1,529,148
Account No. 389.6	PTD	113,871	234	26,420	87,217
Account No. 390	PTD	20,644,102	42,499	4,789,752	15,811,850
Account No. 390.6	PTD	981,759	2,021	227,783	751,955
Account No. 391	PTD	2,024,393	4,168	469,691	1,550,535
Account No. 391.1	PTD	1,908,588	3,929	442,822	1,461,837
Account No. 391.2	PTD	2,529,628	5,208	586,913	1,937,507
Account No. 397.1	PTD	5,165,182	10,633	1,198,403	3,956,146
Account No. 397.3	PTD	2,689,794	5,537	624,074	2,060,182
Account No. 398	PTD	803,183	1,653	186,351	615,178
Total		\$38,856,970	\$79,994	\$9,015,421	\$29,761,556

NWE As-Amended Common Plant					
Common Plant	Funct.	Plant	Production	Transmission	Distribution
Account No. 389	PTD	1,996,471	4,110	463,212	1,529,148
Account No. 389.6	PTD	113,871	234	26,420	87,217
Account No. 390	PTD	20,644,102	42,499	4,789,752	15,811,850
Account No. 390.6	PTD	981,759	2,021	227,783	751,955
Account No. 391	LABOR	2,024,393	39,714	360,531	1,624,148
Account No. 391.1	LABOR	2,024,394	39,714	360,531	1,624,149
Account No. 391.2	LABOR	2,024,395	39,714	360,531	1,624,150
Account No. 397.1	PTD	5,165,182	10,633	1,198,403	3,956,146
Account No. 397.3	PTD	2,689,794	5,537	624,074	2,060,182
Account No. 398	PTD	803,183	1,653	186,351	615,178
Total		\$38,467,544	\$185,831	\$8,597,589	\$29,684,124

NWE As-Filed Common Plant Depreciation Reserve					
Common Plant	Funct.	Plant	Production	Transmission	Distribution
Account No. 389	PTD	115,337	237	26,760	88,339
Account No. 389.6	PTD	599	1	139	459
Account No. 390	PTD	(4,592,330)	(9,454)	(1,065,492)	(3,517,384)
Account No. 390.6	PTD	(120,847)	(249)	(28,038)	(92,559)
Account No. 391	PTD	(1,767,923)	(3,640)	(410,186)	(1,354,098)
Account No. 391.1	PTD	(1,668,834)	(3,436)	(387,195)	(1,278,203)
Account No. 391.2	PTD	(850,131)	(1,750)	(197,244)	(651,138)
Account No. 397.1	PTD	(1,797,359)	(3,700)	(417,015)	(1,376,644)
Account No. 397.3	PTD	(2,976,512)	(6,128)	(690,597)	(2,279,787)
Account No. 398	PTD	(595,879)	(1,227)	(138,253)	(456,399)
Total		(\$14,253,880)	(\$29,344)	(\$3,307,122)	(\$10,917,414)

NWE As-Amended Common Plant Depreciation Reserve					
Common Plant	Funct.	Plant	Production	Transmission	Distribution
Account No. 389	PTD	115,337	237	26,760	88,339
Account No. 389.6	PTD	599	1	139	459
Account No. 390	PTD	(4,592,330)	(9,454)	(1,065,492)	(3,517,384)
Account No. 390.6	PTD	(120,847)	(249)	(28,038)	(92,559)
Account No. 391	LABOR	(1,767,923)	(34,683)	(314,855)	(1,418,385)
Account No. 391.1	LABOR	(1,668,834)	(32,739)	(297,208)	(1,338,887)
Account No. 391.2	LABOR	(850,131)	(16,678)	(151,403)	(682,051)
Account No. 397.1	PTD	(1,797,359)	(3,700)	(417,015)	(1,376,644)
Account No. 397.3	PTD	(2,976,512)	(6,128)	(690,597)	(2,279,787)
Account No. 398	PTD	(595,879)	(1,227)	(138,253)	(456,399)
Total		(\$14,253,880)	(\$104,618)	(\$3,075,963)	(\$11,073,299)

NWE As-Filed Common Plant Depreciation Expense					
Common Plant	Funct.	Plant	Production	Transmission	Distribution
Account No. 389	PTD	-	0	0	0
Account No. 389.6	PTD	-	0	0	0
Account No. 390	PTD	790,080	1,627	183,311	605,143
Account No. 390.6	PTD	24,338	50	5,647	18,641
Account No. 391	PTD	102,392	211	23,756	78,424
Account No. 391.1	PTD	96,126	198	22,303	73,625
Account No. 391.2	PTD	318,397	655	73,873	243,868
Account No. 397.1	PTD	357,233	735	82,884	273,614
Account No. 397.3	PTD	303,690	625	70,461	232,604
Account No. 398	PTD	37,288	77	8,651	28,560
Total		\$2,029,544	\$4,178	\$470,886	\$1,554,480

NWE As-Amended Common Plant Depreciation Expense					
Common Plant	Funct.	Plant	Production	Transmission	Distribution
Account No. 389	PTD	0	0	0	0
Account No. 389.6	PTD	0	0	0	0
Account No. 390	PTD	790,080	1,627	183,311	605,143
Account No. 390.6	PTD	24,338	50	5,647	18,641
Account No. 391	LABOR	102,392	2,009	18,223	82,160
Account No. 391.1	LABOR	96,126	1,886	17,108	77,133
Account No. 391.2	LABOR	318,397	6,246	56,665	255,485
Account No. 397.1	PTD	357,233	735	82,884	273,614
Account No. 397.3	PTD	303,690	625	70,461	232,604
Account No. 398	PTD	37,288	77	8,651	28,560
Total		\$2,029,544	\$13,255	\$442,949	\$1,573,340

4.3. Schedule 1A: Cash Working Capital

No direct adjustment.

4.4. Schedule 2: Capital Structure and Rate of Return

4.4.1. 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.

In the Draft ASC Report, BPA proposed to use NWE's last determined ROE for establishing NWE's ASC. In its Comments on the Draft ASC Report, NWE states that they agree with BPA's decision to use a 2000 MPSC rate order for Montana Power Company as a proxy for NWE's rate of return. *See* NWE Comments on BPA Draft ASC Report, pg. 3, filed May 6, 2009.

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.

18 CFR Pt 301, Table 1.

NWE's situation is unique due to 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 2010 ASC Appendix 1 filings.

Utility	Allowed ROE	ASC Rate of Return
Avista		10.96%
Avista – Washington	10.20%	
Avista – Idaho	10.20%	
Idaho Power		10.95%
Idaho Power – Idaho	10.60%	
Idaho Power – Oregon	10.00%	
NorthWestern	10.75%	11.20%
PacifiCorp		10.87%
PacifiCorp – Idaho	10.25%	
PacifiCorp – Oregon	10.00%	
PacifiCorp – Washington	10.20%	
Portland General Electric	10.10%	11.01%
Puget Sound Power and Light	10.15%	10.77%
Average		10.96%

While NWE's ASC rate of return is the highest rate of return among the filing IOUs, it is only fractionally higher, 0.19%, than PGE's return, the next highest return, and 0.24% higher than the average return of all filing utilities for the 2010 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, provides 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.

See 18 CFR § 301.4(c).

Based on BPA's review of 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 2010 ASC filings, BPA will accept NWE's proposed ROE and capital structure for this Final ASC Report. BPA's decision to use the ROE approved for MPC, however, will be evaluated as necessary in future ASC proceedings.

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.

4.5. Schedule 3: Expenses

4.5.1. 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 performed a Direct Analysis on Account 565, Transmission of Electricity by Others – Wheeling, and assigned a portion of the costs from this account to Distribution/Other. Table 1 of the 2008 ASCM, however, requires that all items in Account 565 be functionalized to Transmission. See 18 CFR Pt 301, Table 1.

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.

Subsequently, in NWE Comments on BPA Draft ASC Report, pg. 4, filed May 6, 2009, NWE stated that they agreed with BPA's decision in the Draft ASC Report to functionalization all of Account 565 to Transmission.

Parties' Positions:

Although NWE initially functionalized Account 565 with a Direct Analysis, NWE now agrees that with BPA that the entire account must be assigned 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. See 18 CFR Pt 301, Table 1. BPA agrees with NWE that because lines over which the power flows are not owned by NWE, Account 565 - Transmission of Electricity by Others should be functionalized to Transmission.

Decision:

BPA will functionalize Account 565 to Transmission.

Table 4.5.1: Account 565 – Transmission of Electricity by Others: (\$)

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	4,896,956		4,187,322	709,634
BPA Adjusted	4,896,956		4,896,956	

4.5.2. 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:

In Response to BPA Data Request No. 2, filed February 6, 2009, NWE 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/Other 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. In this meeting, BPA informed NWE Staff that all conservation-related expenses, including advertising and promotion expenses, can be functionalized to Production under the 2008 ASCM. 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/Other.

BPA's review of this data revealed that NWE still may have functionalized valid conservation-related program costs to Distribution.

In NWE Comments on BPA Draft ASC Report, pg. 4, filed May 6, 2009, NWE stated that it ". . . supports BPA's decision. NWE revised the Direct Analysis to include all costs as Production-related except the bill assistance payments."

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 allow utilities to perform a Direct Analysis on any account that contains conservation program costs. Section VIII, Subsection B.3 provides:

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.

18 CFR § 301.9(d)(1).

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.

In addition, the 2008 ASCM states 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.

Id.

Further, the 2008 ASCM also states that:

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.

18 CFR § 301.9(d)(3).

BPA reviewed the additional information supplied by NWE with their May 6, 2009 comments on BPA's Draft ASC Report. Based on BPA's review of this information, BPA will accept NWE's revised Direct Analysis of Account 930.2 – Miscellaneous General Expenses - Conservation Costs.

Decision:

BPA accepts NWE's revised Direct Analysis and will functionalize this account based on NWE's revised Direct Analysis submitted on May 6, 2009.

Table 4.5.2: Account 930.2 Miscellaneous General Expenses - Conservation Costs (\$)

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	10,369,115	1,677,454	0	9,010,796
BPA Adjusted	10,369,115	7,530,254	0	2,838,861

4.6. Schedule 3A: Taxes

No direct adjustment.

4.7. Schedule 3B: Other Included Items

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

Statement of Issue:

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?

Statement of Facts:

NWE's Appendix 1 template functionalized a portion of Account 456.1 to Distribution/Other. The documentation that NWE submitted with its Appendix 1 indicated that NWE functionalized Account 456.1 using a Direct Analysis based on FERC's Seven Factor Test. NWE's analysis indicated that 34 percent of NWE's total transmission plant was distribution-related. Based on this analysis, NWE functionalized 34 percent 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. Thus, to support its

functionalization of Account 456.1, NWE relied on the provisions of Endnote i of the ASCM. Specifically, 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.

NWE's Response to BPA Issue List pg. 4, filed February 11, 2009.

In the Draft ASC Report, BPA rejected NWE's Direct Analysis and functionalized the entirety of Account 456.1 to Transmission. In response, in its Comments on the Draft ASC Report, NWE stated that

. . . it did in fact use the same analysis and did move plant balances and O&M expenses from Transmission to Distribution. For reference, look at the "Tran Plt_Functionalized" and "Tran O&M_Functionalized" tabs in the Appendix 1 filing. Because NWE believes that the direct analysis included in the filing is consistent between plant, expenses and revenue, NWE proposes that BPA accept the direct analysis used by NWE. NWE would also suggest that if BPA's final report retains the decision stated here then a corresponding adjustment to plant and O&M expenses reflecting 100% transmission is necessary in order to maintain consistency between expense and revenue.

NWE Comments on BPA Draft ASC Report, pg. 4, filed May 6, 2009.

Parties' Positions:

NWE argues that a portion of Account 456.1 must be functionalized to Distribution/Other.

Analysis of Position:

Table 1 of the 2008 ASCM provides that the functionalization method for this account is transmission with no optional functionalization. *See* 18 CFR Pt 301, Table 1.

However, Appendix 1, Section IX, Endnote i of the 2008 ASCM states that

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

18 CFR § 301.9, Appendix 1, Endnote i.

The description of Account 456.1 in the FERC Uniform System of Accounts states that “[t]his 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. 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 percent of NWE's transmission plant classified as Distribution. Thus, NWE's supporting documentation appears to support its functionalization of Account 565.

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.

BPA reviewed the filing and supporting documentation and agrees that NWE’s analysis is a valid Direct Analysis that complies with Endnote i of the 2008 ASCM.

Decision:

BPA accepts NWE’s Direct Analysis and will functionalize Account 456.1, (Revenue from the Transmission of Electricity of Others) pursuant to the functionalization developed by NWE.

Table 4.7.1: Account 421 Miscellaneous Non-operating Income: (\$)

	<u>Total</u>	<u>Production</u>	<u>Transmission</u>	<u>Dist/Other</u>
As-Filed	50,430,973	0	32,622,057	17,088,916
BPA Adjusted	50,430,973	0	32,622,057	17,088,916

4.8. SCHEDULE 4: Average System Cost

No direct adjustment.

5. SUPPORTING DOCUMENTATION:

5.1. Purchased Power and Sales for Resale

No direct adjustment.

5.2. SUPPORTING DOCUMENTATION: Salaries and Wages

No direct adjustment.

5.3. SUPPORTING DOCUMENTATION: Labor Ratios

No direct adjustment.

5.4. DISTRIBUTION LOSS FACTOR

No direct adjustment.

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 contained the same data for the years 2005, 2006 and 2007.

Parties' Positions:

NWE proposes to use a price spread of 11.54 percent 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 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.

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.

18 CFR § 301.5(a).

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.

Because NWE did not document its price spread calculation, BPA made the calculation using information from NWE’s Appendix 1 filing. This calculation must be performed because 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 and 2007 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 14.66 percent. BPA will use 14.66 percent as the price spread in the ASC Forecast Model.

In NWE Comments on BPA Draft ASC Report, pg. 5, filed May 6, 2009, NWE stated that they agreed with BPA’s decision on BPA’s decision on the price spread between the purchased power and sales for resale.

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

NorthWestern Energy
2007
October 15, 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	\$9,443,497	\$101,948	\$21,452,392	\$286,516		
LF	326-327	149,104,172	3,783,261	118,386,444	3,536,694		
IF	326-327	0	0	0	0		
SF	326-327	97,444,421	1,895,049	103,536,270	2,156,156		
LU	326-327	84,449,934	1,725,957	67,719,154	1,290,616		
IU	326-327	108,775	3,677	117,976	3,719		
OS	326-327	3,238,324	11,960	40,401	800		
EX	326-327	(34,870)	(522)	100,610	1,922		
NA	326-327	0	0	0	0		
AD	326-327	0	0	0	0		
TOTAL		\$343,754,253	\$7,521,330	\$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	\$ -	-	\$ -	-		
LF	310-311	\$ -	-	\$ -	-		
IF	310-311	\$ -	-	\$ -	-		
SF	310-311	\$ 55,126,295	1,444,555	\$ 47,339,878	1,267,830		
LU	310-311	\$ -	-	\$ -	-		
IU	310-311	\$ -	-	\$ -	-		
OS	310-311	\$ -	-	\$ -	-		
EX	310-311	\$ -	-	\$ -	-		
NA	310-311	\$ -	-	\$ -	-		
AD	310-311	\$ -	-	\$ -	-		
TOTAL		\$ 55,126,295	1,444,555	\$ 47,339,878	1,267,830		

Price Spread		14.66%	
	2007	2006	
Average PP	52.79	48.02	
Average SS	38.16	37.34	
1/2 differenc	7.32	5.34	
Mid Point	45.48	42.68	
	16.09%	12.52%	
	14.66%		

Decision:

BPA will use 14.66 percent 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 its Appendix 1 template which was not discovered by BPA Staff until the final quality control review of the Draft ASC 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, it did not modify the ASC Appendix 1 Model. The result of this omission was that the production-related costs in Account 930.2 were not included in the ASC Forecast model.

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/Other with no optional functionalization. *See* 18 CFR Pt 301, Table 1. 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.

18 CFR § 301.9(d)(1).

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/Other. However, NWE records conservation costs in Account 930.2 – Miscellaneous General Expenses. The functionalization for Account 930.2 is Distribution/Other, 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.

Decision:

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

5.5.3. ASC Forecast Model: Natural Gas Escalators and Market Price of Electricity

Statement of Issue:

Whether BPA should update the ASC Forecast Model escalators to reflect the natural gas and market price of electricity forecasts developed in BPA's 2010 Final Wholesale Power Rate Proposal.

Statement of Facts:

Section IV.A.2 of the 2008 ASCM states that:

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

18 CFR § 301.5(a)(2).

Section 4.2.1 of the 2008 ASCM ROD states that the:

.... use of these escalators will ensure parity in the forecast of costs included in BPA rates and costs included in ASCs during the rate period and Exchange Period.

2008 ASCM ROD at 39.

Parties' Positions:

No party raised any comments on this issue.

Analysis of Positions:

As noted at the beginning of this ASC Report, utilities' ASCs make up only one component of the formula used to determine a utility's benefits under the Residential Exchange Program. In addition to a utility's ASC, BPA must also calculate a PF Exchange rate, which is being established in BPA's WP-10 Rate Proceeding. The PF Exchange rate generally reflects BPA's cost of power, with certain surcharges as required by section 7 of the Northwest Power Act. Although BPA's PF Exchange rate and the utilities' ASCs are established under different criteria, both sets of rates use certain common inputs. The forecasts used to determine the market prices of electricity and natural gas are one area where there is an overlap in the rate inputs.

The forecasts of electricity prices and natural gas prices play a significant role in determining the level of both the PF Exchange rate and utilities' ASCs. For example, they affect BPA's PF Exchange rate in that they determine the level of secondary revenue that is used to credit against

BPA’s cost of power. For ASCs, these forecasts impact the value the utility receives for its sales for resale and the costs the utility incurs for purchasing power on the open market. Because these forecasts are a central driver in establishing both sets of rates, the ASCM provides that BPA will use its own forecast for these commodities when calculating the escalators in the ASC Forecast Model. 18 CFR § 301.5(a)(2). As noted above, the Administrator explained in the ASCM ROD that these BPA-generated forecasts were essential because they “will ensure parity in the forecast of costs included in BPA rates and costs included in ASCs during the rate period and Exchange Period.” 2008 ASCM ROD at 39. Without this parity, there could be a serious misalignment between the inputs used to determine BPA’s PF Exchange rate and the utilities’ ASCs, which could potentially result in abnormally high or low payments to utilities participating in the Residential Exchange Program.

Consistent with the terms of the ASCM and the ASCM ROD, for this Final ASC Report BPA has updated the electricity price forecast and natural gas price forecast used to determine the escalators in the ASC Forecast Model. BPA used the forecasts developed in BPA’s Final Rate Proposal in the WP-10 Rate Proceeding as the source of its data for these updates. BPA chose the WP-10 Final Rate Proposal as its source of data because these forecasts are the most current available and reflect market conditions and BPA’s expectation for future energy prices. In addition, the Final Rate Proposal forecasts achieve the parity described in the ASCM ROD by ensuring the market price assumptions used to set BPA’s PF Exchange rate are consistent with the forecasts used to establish utilities’ ASCs.

Decision:

BPA will update the ASC Forecast Model escalators to reflect the natural gas price forecast and market price of electricity forecast developed in BPA’s 2010 Final Wholesale Power Rate Proposal.

Table 5.5.3a: ASC Forecast Model: Natural Gas Escalators

Calendar Year	<u>Price Escalators</u>			
	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>
As-Filed	33.8%	-19.4%	5.3%	-2.6%
Final	24.8%	-50.3%	30.0%	2.7%

See Excel File NWE_ASC_Forecast_Model_FY2010-11_Final.xls

Table 5.5.3b: ASC Forecast Model: Market Price of Electricity Escalators

Fiscal Year	<u>Price Escalators</u>			
	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>
As-Filed	26%	-23%	2%	2%
Final	19%	-23%	-19%	8%

See Excel File NWE_ASC_Forecast_Model_FY2010-11_Final.xls

5.5.4. ASC FORECAST MODEL: Price of BPA Power Products

Statement of Issue:

Whether BPA should update the ASC Forecast Model escalators to reflect the price of BPA power products developed in BPA’s 2010 Final Wholesale Power Rate Proposal.

Statement of Facts:

Section IV.A.2 of the 2008 ASCM states that:

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

18 CFR § 301.5(a)(2).

Section 4.2.1 of the 2008 ASCM ROD states that the:

.... use of these escalators will ensure parity in the forecast of costs included in BPA rates and costs included in ASCs during the rate period and Exchange Period.

2008 ASCM ROD at 39.

Parties’ Positions:

No party raised any comments on this issue.

Analysis of Positions:

This issue is similar to the issue described above in Section 5.5.3. Consistent with the terms of the ASCM and the ASCM ROD, for this Final ASC Report BPA has updated the price of BPA power products to determine the escalators in the ASC Forecast Model. BPA used the prices developed in BPA’s Final Rate Proposal in the WP-10 Rate Proceeding as the source of its data

for these updates. Updating the ASC Forecast Model escalators with BPA’s final rates from WP-10 Final Rate Proposal is reasonable because these prices reflect the actual rates BPA will charge during the Exchange Period for BPA’s power products. In addition, the Final Rate Proposal rates achieve the parity described in the ASCM ROD by ensuring there is no misalignment between the cost components used to determine BPA’s PF Exchange rate and the cost components used to determine the utilities’ ASCs.

Decision:

BPA will update the ASC Forecast Model escalators to reflect the price of BPA power products developed in BPA’s 2010 Final Wholesale Power Rate Proposal.

Table 5.5.4a: ASC Forecast Model: Purchased Power PF

	<u>Price Escalators</u>			
Fiscal Year	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>
As-Filed	0.0%	-3.7%	3.8%	0.0%
Final	0.0%	-3.7%	7.0%	0.0%

See Excel File NWE_ASC_Forecast_Model_FY2010-11_Final.xls

Table 5.5.4b: ASC Forecast Model: Purchased Power Slice

	<u>Price Escalators</u>			
Fiscal Year	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>
As-Filed	0.0%	-3.7%	3.8%	0.0%
Final	0.0%	-0.2%	4.5%	0.0%

See Excel File NWE_ASC_Forecast_Model_FY2010-11_Final.xls

6. OTHER ISSUES

6.1. Generic Issue List

In addition to the above-noted issues specific to the determination of NWE's ASC, BPA raised seven issues that may be "generic" to all Exchanging utilities. The following issues were discussed with the parties during the ASC Review Process and were published in the ASC Draft Reports. In general, the IOUs responded in unison. Puget Sound submitted additional comments. Franklin PUD did not respond in writing.

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 BPA's review of the exchanging utilities' ASC filings, BPA noticed that the Direct Analysis performed by the utilities resulted in different functionalization for similar types of software. For example, metering and customer information system (CIS) software was functionalized to Distribution/Other by PGE while Avista, IPC, PAC, PSE and NorthWestern functionalized such software using the PTD ratio. Section VIII of the ASCM specifies that the default functionalization for Account 303 – Intangible Plant - Miscellaneous is Direct Analysis, with an option to functionalize the Account to Distribution/Other.

The documentation supplied by the utilities to support use of the PTD ratio to functionalize items in Account 303 – Software was minimal.

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.

IOU Generic Issue List Responses, pg. 1, filed February 25, 2009.

However, parties filed separate responses concerning functionalization of software included in Account 303. For example, PSE 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.

PSE Generic Issue List Responses, pg. 1, filed February 25, 2009.

In PAC's February 11, 2009, response to BPA's Issues List, PAC repeatedly stated 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." PAC Issue List Responses to BPA, pg. 3, filed February 11, 2009.

Later, however, PAC offered the following answer in response to an issue BPA raised regarding a specific piece of software. In response to BPA's functionalization of a Customer Information System, PAC argued that "[i]n determining the proper functionalization, the focus should be on what costs the Company is recovering using this computer software." PACs Issue List Responses to BPA, pg. 2, filed February 11, 2009.

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.

PGE Issue List Responses to BPA, pg. 1, filed February 11, 2009.

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.

NorthWestern Energy Issue List Responses to BPA, pg. 1, filed February 11, 2009.

Snohomish County PUD's February 27, 2009, response to BPA's Issues List argued that:

BPA should maintain consistency in the functionalization of these common types of software assets, with costs greater than an identified threshold value, amongst utilities when calculating ASC.

Snohomish supports a consistent treatment for the accounting of similar types of software assets, but suggests that BPA also maintain direct assignment as an alternative.

On page 5 of PSE's comments on BPA's Draft ASC Report, PSE expressed concern about the manner in which the software functionalization was developed and whether it adequately and accurately reflects PSE's software. *See* PSE Comments on BPA Draft ASC Report, pg. 5, filed May 11, 2009. For example, PSE is concerned that BPA associated the name of PSE software with the name of similar commercial products, resulting in misidentification of software. *Id.* In addition, PSE notes that commercial software is often modified and enhanced considerably to meet the requirements of a utility. *Id.* PSE is also concerned that BPA's software functionalization framework predetermines the functionalization of a software asset. *Id.* Finally, PSE suggests that BPA's software functionalization framework raises the burden on utilities that have tailored/enhanced software, which the utility believes changes the functional nature of software from the functionalization contained in BPA's general framework. *Id.*

PSE raised the following specific questions:

- How the general framework presented in Section 6.1.1 of the ASC Draft Report would be implemented in the ASC.
- Can a utility use the general framework as an alternative to Direct Analysis?
- If a utility were to use the general framework, would the utility need to provide additional documentation regarding the use of the functionalization method identified in the general framework, particularly if the general framework would functionalize the software systems to something other than Distribution?
- Does the 1% threshold apply for any asset in Account 303? If so, is the resulting functionalization Labor?

- How would the threshold work if a utility has software assets in both common and electric Accounts 303?

Id. at 5-6.

PSE requested that the listing of software assets as included in its April 2009 Draft ASC Report at pages 35-40 be described as preliminary and that the topic of software functionalization be addressed more fully in a workshop contemporaneous with the other discussions/workshops anticipated in the Draft ASC Report. *Id.*

Software systems should be functionalized to follow the operation they support or the labor expense that the software replaced.

Analysis of Positions:

Section VIII.B, Table 1 of the 2008 ASCM provides that functionalization of Account 303 is Direct Analysis with an option to Distribution/Other. *See* 18 CFR Pt. 301, Table 1.

The 2008 ASCM states as follows:

Functionalization of each Account included in a utility's ASC must be according to the functionalization prescribed in Table 1, *Functionalization and Escalation Codes*. 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 § 301.9(a).

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:

Bonneville 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 § 301.9(d)(2).

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 provided by the utilities was generally nothing more than a generic statement that the software supported all of the utility's business functions. As a result, BPA was unable to determine whether the proffered functionalization treatment was

appropriate. For example, some of the statements included by utilities to support functionalization of a specific piece of software with the PTD ratio used terms like “supports all functions of the company”³ or “supports all areas of the company.”⁴ These catchall phrases, if allowed to serve as evidence of a Direct Analysis, could be used to support functionalizing the entire ASC filing with the PTD ratio. Such generic statements do not constitute a valid Direct Analysis under the ASCM.

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 1,000 or more unique software products that comprise a typical utility’s software assets is a very time-consuming process. 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 that incorporate most, if not all, Production, Transmission, and Distribution costs of the utility. State commissions are generally less concerned if, for example, call center software, which is clearly related to the Distribution function, and generation maintenance software, which is clearly related to the Production function, are both functionalized with the PTD or Labor ratio. For most utilities, software represents a small percentage of net plant in service, between 1% and 5% for exchanging utilities. Thus, even if software assets are not correctly functionalized, it is unlikely that it would affect retail rates.

However, a utility’s ASC may include only allowable production and transmission costs as determined in accordance with the 2008 ASCM. Using the PTD or Labor ratio for all software costs may result in the inclusion of inappropriate costs in a utility’s ASC. For example, the costs of certain software packages are very large relative to others in Account 303, which could cause simple ratios to functionalize a large portion of distribution-related software into ASC. For example, in PAC’s Response to BPA Data Request No. 12, PAC 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.

³ See, for example, Data Responses ASC-10 PA-BPA-8 and ASC-10-PS-BPA-5

⁴ See, for example, Data Response ASC-10-PS-BPA-5, and Excel file E302_303_399_Common_NBV_2007_Final.xls, DATA for ASC tab, column W.

This and other examples BPA found in the utilities' ASCs Filings caused BPA to be concerned that, without more documentation and support, utilities could potentially include tens of millions of dollars of inappropriate costs in their ASCs through Account 303.

The 2008 ASCM is clear that if a utility does not provide, or chooses not to provide, sufficient detail so that BPA can determine the functional nature of Account 303 software assets, the software assets will be functionalized to Distribution/Other. *See* 2008 ASCM, Section VIII.B, Table 1; *see* 18 CFR Pt. 301, Table 1. Rather than simply functionalize all of the items in Account 303 to Distribution/Other (which would be allowed under the ASCM), BPA decided to develop a general framework for evaluating software in Account 303. This framework served as a reference point as BPA considered the functionalization for the various software assets. BPA took these extra steps to ensure that software costs would 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, BPA's generic software asset approach should help utilities that do not want to undertake the task of functionalizing all of the items in Account 303. The existence of BPA's general framework will not eliminate an exchanging utility's right to support a different functionalization through its own Direct Analysis.

In fact, for two utilities, Idaho and NWE, BPA reviewed the list of software assets provided by the utilities and functionalized the software based on the general framework and BPA's understanding and knowledge of the software. The BPA functionalization was then sent to the utilities for review. BPA discussed its preliminary decisions with the utility and made adjustments based on discussions with the utility about the nature and use of the software assets.

PSE's response to BPA's Draft ASC Report raised two general concerns regarding the use of BPA's general software functionalization framework. *See* PSE Comments on BPA Draft ASC Report, pg. 5-6, filed May 11, 2009.

First, PSE raised general concerns regarding the manner in which BPA developed the general software functionalization framework and whether BPA's framework "adequately/accurately reflects PSE's software which may appear to have the same/similar name." *Id.* at 5. Specifically, PSE stated that BPA attempted "to associate certain software assets by name with similarly named commercially available software assets." *Id.* at 5.

The functionalization rules of the 2008 ASCM state that:

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

2008 ASCM, Section VIII.A.2; 18 CFR § 301.9(c)(2).

In most cases, utilities, including PSE, did not perform a Direct Analysis on individual software assets. Instead, they relied on simple ratios to functionalize all software assets as a group

without explaining why the ratios were appropriate. BPA functionalized the individual software assets *based on the information provided by the utility* to BPA in response to data requests and Issue Lists. The information provided by PSE and other utilities was primarily a simple listing of the software assets from an internal database and associated cost data. In many cases, the software asset list did not even contain the commercial name of the software asset.

Examples of items contained on software asset lists submitted to BPA by Idaho and NWE that were reviewed under a Direct Analysis include the Phoenix Project – Phase 1, Feeder Fielding Project, and Wire Vision Implementation (*see IPC’s Response to BPA Data Request 5, filed November 20, 2008*); and IT Infrastructure Software, GUIXT Graphical Interface, and IT MTU Info Mobile Data Comp (*see NWE’s Response to BPA Data Request 5, filed February 20, 2009*). Other than cost data associated with the software asset, utilities generally did not provide any other information about the use or function of these programs. BPA functionalized as many as 200 software assets for a utility based on nothing more than information similar to that shown in the previous example.

PSE argues that BPA’s functionalization is inappropriate because BPA has used the name of the software in Account 303 as the means of functionalizing the respective programs. *See PSE Comments on BPA Draft ASC Report, pg. 5, filed May 11, 2009*. PSE is concerned that this approach may have misidentified some items in Account 303 because the name of PSE’s software does not always serve the same function as commercial software with the same or similar name. *Id.*

PSE’s concerns are misplaced. First, to be clear, it is the *utility’s* responsibility to submit to BPA sufficient documentation and information to support a Direct Analysis. *See 2008 ASCM, Section VIII.B.2; 18 CFR § 301.9(d)(2)* (“*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.*”) *Emphasis added.* As such, BPA could have functionalized all of the software assets in Account 303 to Distribution/Other because the information supplied by the utilities did not support the utilities’ suggested functionalizations, generally PTD. However, because this Final ASC Report concerns one of the first ASCs to be determined under the 2008 ASCM, BPA decided to allow certain software costs into ASC, provided that BPA could confirm that the software was generally used in the utility industry for resource-related activities. BPA believed that the software name was an appropriate identifier because review of corporate information provided by the software developer can generally result in identification of the proper functionalization of a software asset.

To the extent that PSE believes BPA misidentified any software assets, PSE had opportunities to supply BPA with additional information through its Direct Analysis or in response to BPA’s data requests. For example, PSE could have provided the commercial name of the software and the primary users or function of the software, which would have greatly increased BPA’s understanding of the software’s use and purpose. Because PSE did not supply this information, Account 303 has been functionalized in a manner that is consistent with the evidence that was provided to BPA during the ASC Review Process.

PSE also states that commercial software is often significantly modified and enhanced and that such modifications “may necessitate a change in the functionalization used in the ASC.” *See* PSE Comments on BPA Draft ASC Report, pg. 5, filed May 11, 2009. Additionally, PSE argues that BPA’s software framework “predetermines a software asset’s functionality and, by its existence raises the burden on the utility to accomplish a change to the tailored/enhanced software different from that shown in the general framework.” *Id.* In response, BPA notes that if PSE has modified/tailored/enhanced a software asset such that its function is different than what is shown in BPA’s general software functionalization framework, PSE may describe the modifications in its ASC filing or in response to BPA’s data requests or issue lists.

PSE suggested that because of its concerns, BPA should state that the general software functionalization framework is preliminary and be the subject of future ASC workshops. *Id.* at 5. BPA agrees. The general framework for software assets described below will not be considered precedential for future ASC filings. BPA intends to revisit the software descriptions and functionalizations provided below in a workshop on its general software functionalization framework in September 2009.

PSE’s response to BPA’s Draft ASC Report also raised seven specific questions concerning the use of BPA’s general software functionalization framework. *Id.*

PSE’s first question asked if the general framework is an alternative to Direct Analysis. *Id.* In response, BPA notes that the general software functionalization template is not a substitute for a valid Direct Analysis. Rather, the template reflects BPA’s understanding of the functional nature of the categories of software assets that are in general use by electric utilities.

PSE’s second question asked BPA to clarify that if a utility were to use BPA’s general framework, “would the utility need to provide additional documentation regarding the use of the functionalization method identified in the general framework, particularly if the general framework would functionalize the software systems to something other than Distribution?” *Id.* at 6. In response, the utility must provide sufficient documentation with its ASC filing so that BPA can determine that a software asset is correctly identified and functionalized. For example, the utility cannot simply provide a list containing software assets such as Wire Vision Implementation, Silicon Energy Software, Envision Management System Software and state that they are ERP or Wholesale Billing and Settlement and functionalize them via the Labor ratio. The utility would need to supply the software name and a brief description of its use. BPA will work with the utilities to determine the required information for software assets in the September 2009 ASC workshop.

PSE’s third question asked if “the 1% threshold appl[ies] for any asset in Account 303? If so, is the resulting functionalization Labor? How would the threshold work if a utility has software assets in both common and electric Accounts 303?” *Id.* at 6. This issue is best left to the September 2009 ASC Workshop on Account 303 software assets.

PSE’s fourth question asked if the “reference to IPC at page 32 of the Draft ASC Report intended to be a reference to PSE?” *Id.* In response, BPA made a typographical error in referencing IPC. The correct reference should have been to PSE.

PSE's fifth question concerned a sentence on page 34 of PSE's Draft ASC Report that PSE thought was unclear and asked that it be clarified in future ASC workshops. *Id.* BPA will discuss the meaning and intent of the referenced sentence in a future ASC workshop.

PSE's sixth question asked if the following interrogatory sentence was intended to be a declaratory sentence:

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?

Id. at 6. PSE is correct. The question mark at the end of the sentence should be a period and the above-referenced sentence should be declaratory.

PSE's seventh and final question asked if the determination in Section 6.1.4 requires the balance sheet accounts to be functionalized in the same manner as the related income statement accounts. *Id.* at 6. In response, BPA intends to functionalize regulatory assets and liabilities that are allowed in rate base for ASC purposes in a manner consistent with the rules and procedures of the 2008 ASCM.

BPA will schedule workshops after publication of the FY 2010-2011 Final ASC Reports to discuss the general software functionalization framework for Account 303. Utilities will have an opportunity to fully explore and analyze the general software functionalization framework, suggest changes and modifications to software definitions and functionalizations and the relationship between the general software functionalization framework and the documentation requirements for a Direct Analysis for Account 303.

Decision:

BPA will adopt a common functionalization for similar types of software assets in the FY 2010-2011 Final ASC Reports if the Direct Analysis supplied by the utility can not be substantiated by BPA. Following completion of the FY 2010-2011 Final ASC Reports, BPA intends to conduct workshops with interested parties to more fully explore BPA's general software functionalization framework, software definitions and functionalizations, and the documentation requirements for a Direct Analysis.

System Categories and Related Functionalizations

Below is a list that describes and categorizes the bulk of utility software, including the accounts associated with utility software and the functionalization BPA will use for each type of software. The following categorization reflects BPA's theory of software asset functionalization. In general, the primary purpose of utility software assets is to reduce labor cost, improve efficiency and provide better access to information and, therefore, software assets should be functionalized based on where the labor cost savings or efficiency improvements occur, or the area of the utility organization in which the software is primarily used. For example, CIS and call center software both reduce the cost of operating a call center and increase the efficiency and quality of utilities' interactions with their customers. Utility customer information and call center labor is normally recorded in Accounts 903 - 912, which are functionalized to Distribution/Other in the 2008

ASCM. BPA functionalized CIS and call center software assets to Distribution/Other. Automated meter reading software assets reduce the labor expense associated with reading utility meters and improve the accuracy and timeliness of customer data. Utility meter reading and related expenses are normally recorded in Accounts 901 – 903. BPA functionalized automated meter reading assets to Distribution/Other.

- **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 903-912.
 - *Industrial Billing* – systems that manage the large industrial customers, bill calculation and presentation processes. Distribution - Accounts 903-912.
 - *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 903-912.
 - *Customer Relationship Management (CRM) System* – systems that manage information about the utility’s customers. Distribution - Accounts 903-912.
 - *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:

The IOUs functionalized similar regulatory assets, such as Deferred Pension, Pay and other labor-related assets and liabilities, in a variety of ways. PGE, Avista and NW used the Labor ratio. IPC used the PTD ratio. PSE and PAC functionalized these assets to Distribution/Other. 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.

Parties' Positions:

In PSE's February 25, 2009, response to BPA's Issue List, PSE 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.

PSE Generic Issue List Responses, pg. 2, filed February 25, 2009.

Avista, Idaho Power, NorthWestern, PAC 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." See IOU Generic Issue List Responses, pg. 1, filed February 25, 2009.

BPA Staff advocates the use of consistent decision criteria for common types of regulatory assets and liabilities.

Analysis of Positions:

The 2008 ASCM ROD states that:

[t]he Utility must describe the functional nature of the regulatory asset or liability, whether or not the asset or liability is included in rate base by its state commission(s), and the return or carrying costs allowed by the state commission(s). *Under no conditions would regulatory assets be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates.*

2008 ASCM ROD at 149 (emphasis added).

Regulatory assets and liabilities exist in the balance sheets of electric utilities only because of the effects of regulation. FERC defines them as “assets and liabilities that result from rate actions [of] regulatory agencies.”⁵ In the ASCM ROD, the WUTC noted 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.” 2008 ASCM ROD at 149-150.

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

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

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

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

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

⁷ *Id.*

After review of the parties' comments and the 2008 ASCM ROD, it is clear 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/Other.

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

Decision:

For the FY 2010-2011 ASC Filings, BPA will use consistent decision criteria for common types of regulatory assets and liabilities. If a 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.

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

Statement of Issue:

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

Statement of Facts:

Table 1 of the 2008 ASCM requires a utility to perform a Direct Analysis 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). Assets in Accounts 182.3 and 186 are often offset by corresponding liabilities in Accounts 253 or 254. Because separate Direct Analyses are performed on each account, it is possible that an asset in one account could be functionalized one way, and then a corresponding liability functionalized another. 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.

Parties' Positions:

Avista, IPC, NorthWestern, PAC and PGE's February 25, 2009, joint response to BPA's Issue Lists stated that "[t]he IOUs agree that BPA should require that accounts that have a corresponding asset and liability account have the same functionalization." IOU Generic Issue List Responses, pg 1, filed February 25, 2009.

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 182.3 and 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.

PSE Generic Issue List Responses, pg. 3, filed February 25, 2009.

BPA Staff advocate the use of consistent decision criteria for common types of regulatory assets and liabilities.

Analysis of Positions:

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

Decision:

BPA will use consistent decision criteria for common types of regulatory assets and liabilities. 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 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:

Utilities functionalized regulatory assets and liabilities that are not included in the utility's jurisdictional rate base in various ways. Some items in these accounts are included in working capital for ratemaking purposes. BPA is concerned 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, PAC and PSE functionalized all regulatory assets and liabilities that are not in their jurisdictional rate base to Distribution/Other. IPC, PGE, and Avista, however, functionalized these same types of costs (i.e., not included in jurisdictional rate base) based on the functional nature of the item.

Parties' Positions:

Avista, IPC, NorthWestern, PAC and PGE's February 25, 2009, Response to BPA's Issue List stated that "[t]here 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." IOU Generic Issue List Responses, pg. 3, filed February 25, 2009.

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.

PSE Generic Issue List Responses, pg. 7, filed February 25, 2009.

BPA Staff argue that 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.

Analysis of Positions:

The 2008 ASCM ROD states as follows:

[t]he 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).

As noted previously in the discussion in Section 6.1.2, regulatory assets and liabilities exist in the balance sheets of electric utilities only because of the effects of regulation. Simply because a utility recovers the expense associated with a regulatory asset in rates does not mean that the regulatory asset is also included in the utility's rate base and earning a return.

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

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:

PAC reduced the amount of its purchased power expense and sales for resale revenue by book-

outs and trading adjustments. “Book-outs” are a netting of simultaneous buy and sell transactions of power between two utilities, where only the net or actual power transferred is shown.

The inclusion of book-outs and trading adjustments in purchased power and sales for resale accounts affects the price spread calculation that BPA uses to calculate a utility’s Exchange Period ASC.

Parties’ Positions:

Avista, IPC, NorthWestern, PacifiCorp and PGE’s February 25, 2009, response to BPA’s Issue List stated that “[t]he 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 more 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.

PSE Generic Issue List Responses, pg. 4, filed February 25, 2009.

BPA Staff argue that utilities should not adjust their purchase power and sales for resale for the effects of book-outs and trading adjustments.

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.

Decision:

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

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

Statement of Issue:

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 coming on-line after the Base Period. None of the utilities submitted copies of firm natural gas supply contracts to support their projected natural gas prices.

The primary informational basis of the ASCM is the use of utility-specific FERC Form 1 filings for IOUs and similar data for COUs. Use of utility-specific forecast data is consistent with this approach.

Parties' Positions:

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

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

IOU Generic Issue List Responses, pg. 2, filed February 25, 2009.

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.

PSE Generic Issue List Responses, pg. 5, filed February 25, 2009.

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

[t]he 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.

OPUC Generic Issue List Response, pg. 1, filed March 3, 2009.

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.

OPUC Generic Issue List Response, pg. 1, filed March 3, 2009.

The OPUC’s March 10, 2009, response to issues reiterated the above statements and stressed 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. OPUC Generic Issue List Response, pg. 1, filed March 10, 2009.

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 a BPA Staff projection. SNOFUD Issue List Response to BPA, Issue 12.

Analysis of Positions:

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

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

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

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

Decision:

BPA will use the natural gas forecast used in the WP-10 Final Rate Proposal for new gas-fired resources in the ASC Forecast Model.

6.1.7. ASC Forecast Model – Capacity Factors

Statement of Issue:

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

Statement of Facts:

When submitting a new resource addition for consideration in the ASC Review Process, utilities must submit a projected capacity factor for the new resource. The submitted projected capacity factors, however, varied significantly between utilities for similar types of new resources.

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.

PSE Generic Issue List Responses, pg. 6, filed February 25, 2009.

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.

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

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

Analysis of Positions:

After discussing this issue with the parties, BPA has decided to use the capacity factors submitted by the utilities for determining the capacity factors for new resources coming on-line during the FY 2010-2011 ASC Exchange Period. This decision to use the utilities' filed capacity factors, however, will be subject to further review in future ASC Review Processes. BPA is deferring this decision 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. This issue should be deferred to future ASC filings to develop more robust estimates of projected capacity factors for new resources.

BPA's decision to use the utilities' submitted capacity factors is also influenced by the fact that several utilities submitted revised capacity factors, which reduced the variance in capacity factors for new generating resources. Partly for this reason, it is reasonable to accept utilities' respective as-filed capacity factors in establishing FY 2010-2011 ASCs.

Decision:

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

6.2. ASC FORECAST MODEL: New Resource Additions during FY 2010-2011

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected

to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

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

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more.

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

Under the 2008 ASCM, the BPA-approved Base Period costs are escalated to the midpoint of the rate period/Exchange Period to calculate Exchange Period ASCs. For a two-year rate period the costs are escalated to the midpoint for a two-year rate period/Exchange Period. To accomplish this, the ASC Forecast Model calculates the Contract System Cost at the start of the rate period, October 1, 2009, and the end of the rate period, September 30, 2011. The midpoint ASC is then calculated as the average of the start of rate period and end of rate period Contract System Costs, divided by the average of the start of rate period and end of rate period Contract System Loads.

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

When the exchanging Utilities submitted their Appendix 1 filings in October 2008, they provided their forecasts of major new resource additions, including all associated costs. For new resources forecast to come on-line during the Exchange Period, all new resource costs except depreciation expense were included at the midpoint of the Exchange Period, October 1, 2010. To calculate the change in ST purchased power expense resulting from new generating resources or new purchased power contracts, the amount of ST power purchases for FY 2011 was decreased by the amount of MWH forecast to be provided by the new generating resource or purchased power

contract. A new 2-year average of ST purchased power MWhs was then calculated. The new 2-year average MWh value was multiplied by the 2-year weighted average purchased power price calculated above to get the new ST purchased power cost included in Contract System Cost.

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

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

7. FY 2010 - 2011 ASC

Overall, BPA's adjustments, including all changes made to NWE's Appendix 1 filing, increased NWE's CY 2007 ASC by \$.51/MWh. The changes increased NWE's FY 2010-2011 ASC by \$2.27/MWh. NorthWestern Energy's FY 2010-2011 ASC is \$57.57MWh.

8. REVIEW SUMMARY

The FY 2010-2011 ASC Review Process is complete with the publication of the Final ASC Reports. BPA requested and reviewed comments on the ASC Draft Reports of all other exchanging utilities for FY 2010-2011. After review of such comments, BPA completed final ASC determinations used to calculate REP benefits for each exchanging utility for FY 2010-2011.

BPA has resolved the issues set forth in Sections 4, 5, and 6 of this report in accordance with the 2008 ASCM and with generally accepted accounting principles. BPA believes the information and analysis contained herein properly establish the NWE's ASC for FY 2010-2011.

This Final ASC Report is BPA's determination of NWE's FY 2010-2011 ASC based on the information and data provided by NWE, including comments in response to the ASC Draft Reports, and based on the professional review, evaluation, and judgment of BPA's REP Staff.

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.

Issued in Portland, Oregon this 14th day of July, 2009.

/s/ Stephen J. Wright

Administrator

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