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

FY 2012–2013

FINAL
AVERAGE SYSTEM COST REPORT

PacifiCorp

July 2011

FY 2012–2013

FINAL
AVERAGE SYSTEM COST REPORT

FOR

PacifiCorp

Docket Number: ASC-12-PC-01
Effective Date: October 1, 2011

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

July 26, 2011

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1 FILING DATA

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

Parties to the Filing:

Investor-Owned Utilities (IOUs):
- Avista Corporation (Avista)
- Idaho Power Company (Idaho Power)
- Portland General Electric (Portland General)
- Puget Sound Energy (Puget)

Consumer-Owned Utilities (COUs):
- Public Utility District No. 1 of Clark County (Clark)
- Public Utility District No. 1 of Snohomish County (Snohomish)

Other Participants to the Filing:
- Idaho Public Utility Commission (IPUC)
- Public Power Council (PPC)
- Public Utility Commission of Oregon (OPUC)

Average System Cost Base Period: Calendar Year (CY) 2009

Effective Exchange Period: Fiscal Year (FY) 2012–2013, October 1, 2011 – September 30, 2013

Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) review to determine PacifiCorp's ASC for FY 2012–2013 based on BPA's 2008 ASC Methodology (2008 ASCM). *See* 18 C.F.R. Part 301, *Sales of Electric Power to the Bonneville Power Administration, Revisions to Average System Cost Methodology* (74 Fed. Reg. 47,052) (2009). This FY 2012–2013 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General information regarding the ASC Review Process can be found at http://www.bpa.gov/corporate/finance/ascm/index.cfm.

NOTE: 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 ASC Draft Reports. If a party failed to do so, the issue is waived for subsequent appeal. *See* Rules of Procedure for BPA's ASC Review Processes, § 3.7.1.3 ("Rules of Procedure").

2 AVERAGE SYSTEM COST SUMMARY

2.1 <u>PacifiCorp Background</u>

PacifiCorp, which includes PacifiCorp and its subsidiaries, serves 1.7 million retail customers, including residential, commercial, industrial, and other customers in a 136,000-square-mile service territory in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho, and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with public and private utilities, energy marketing companies, and incorporated municipalities. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal-mining and environmental remediation services. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company ("MEHC"), a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc.

PacifiCorp owns 15,900 miles of transmission lines and 62,000 miles of distribution lines. In 2009, PacifiCorp's 78 power plants had nameplate generation capacity of about 11,000 megawatts (MW), and they produced 58,404,963 megawatthours (MWh). Details are shown in the table below:

PacifiCorp 2009
Total System Capacity and Energy

Type	Capacity (MW)	Percent	Energy (MWh)	Percent
Coal	6,615	60%	43,855,818	63%
Natural Gas	2,327	21%	8,662,948	12%
Wind	921	8%	2,063,018	3%
Geothermal	38	0%	279,121	0%
Hydro	1,143	10%	3,545,718	5%
Purchases			11,462,391	17%
Misc Adj.			(481,771)	-1%
Total	**11,043**	**100%**	**69,387,243**	**100%**

PacifiCorp, 2009 FERC Form No. 1, April 10, 2010.

2.2 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 most recent audited financial statements (Annual Reports) and underlying accounting system data, including the Cost of Service Analysis, for COUs. For purposes of this FY 2012–2013 filing period, the Base Period is CY 2009. The submitted information includes the "Appendix 1," the Excel-based workbook populated with financial and load data used in calculating the Base Period ASC.

The table below summarizes the CY 2009 Base Period ASC based on (1) the ASC information filed by PacifiCorp on June 1, 2010, including errata, if applicable ("As-Filed"), and (2) the same information as adjusted by BPA ("Final Report"). This table does not reflect the Exchange Period (defined below) ASC, which is noted in subsequent tables.

Table 2.2-1: CY 2009 Base Period ASC
(Results of Appendix 1 calculations)

	June 1, 2010 As-Filed	**July 26, 2011 Final Report**
Production Cost	$1,088,313,324	$1,046,883,138
Transmission Cost	$196,248,229	$192,448,292
(Less) NLSL Costs	$0	$0
Contract System Cost (CSC)	**$1,284,561,553**	**$1,239,331,429**
Total Retail Load (MWh)	20,561,935	20,561,935
(Less) NLSL	0	0
Total Retail Load (Net of NLSL)	20,561,935	20,561,935
Distribution Losses	551,060	551,060
Contract System Load (CSL)	**21,112,995**	**21,112,995**
CY 2009 Base Period ASC (CSC/CSL)	**$60.84/MWh**	**$58.70/MWh**

2.3 FY 2012–2013 Exchange Period ASC

BPA and the intervenors review, evaluate, and comment on the Appendix 1 historical costs and forecast loads submitted in the ASC Review Process. Once the Base Period ASC is determined, the cost data is escalated forward using the "ASC Forecast Model," an Excel-based forecast model, to the midpoint of the Exchange Period, which in this instance is October 1, 2012. For the purposes of this FY 2012–2013 ASC Review Period, the Exchange Period is October 1, 2011 to September 30, 2013 ("Exchange Period").

The following table identifies the Exchange Period ASC that PacifiCorp filed on June 1, 2010, and as adjusted by BPA for this Final ASC Report. If no new resources were to come on line, and no changes were to occur with NLSLs, the ASC shown in Table 2.3-1 below would be the ASC for the entire Exchange Period. See Table 6.1 for details of Exchange Period ASC changes relating to new resources and NLSLs.

Several factors may increase or decrease the Exchange Period ASC from the As-Filed date (June 1, 2010) to the Final ASC Report (July 26, 2011), including adjustments made through the ASC Review Process. Among other changes that may affect a utility's ASC are changes resulting from updates to BPA's natural gas and market price forecasts. For the above-referenced time period, both BPA's natural gas and market price forecasts decreased, resulting in a lower Exchange Period ASC than PacifiCorp's Filing on June 1. For additional details, see Section 3.6 of this report and the "Inputs" tab of the ASC Forecast Model for the utility's (1) As-Filed and (2) BPA-Adjusted models.

Table 2.3-1: Exchange Period FY 2012–2013 ASC ($/MWh)
With No New Resource Additions and No Costs to Serve NLSL Removed

Date	June 1, 2010 As-Filed	July 26, 2011 Final Report
FY 2012–2013	67.68	57.84

2.4 ASC New Resource Additions

Under the 2008 ASCM, a utility's ASC may be adjusted to reflect the addition or loss of a major new resource if such resource commences commercial operation (or ceases production) at any point between the end of the Base Period (December 31, 2009) and the end of the Exchange Period (September 30, 2013). Such new resource must be used to meet a utility's retail load during the Exchange Period.

Before a utility's ASC is adjusted to reflect the addition or loss of a major new resource, the utility must demonstrate that the proposed resource will meet the materiality requirements set forth in the 2008 ASCM. Section 301.4(c) of the 2008 ASCM provides that only resources that affect a utility's Base ASC by 2.5 percent or more will be considered major new resources. 18 C.F.R. § 301.4(c)(4). The 2008 ASCM allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. *Id.* However, each individual resource in the stack must result in a change in Base Period ASC of 0.5 percent or more. *Id.* See also Section 3.4 of this report.

The tables below summarize the new major resource additions projected to become commercially operational and major resource reductions that will cease to be commercially operational by the end of the Exchange Period (September 30, 2013). The As-Filed table reflects the ASC filed by the utility in its June 1, 2010, ASC Filing,. The Final Report table reflects BPA's adjustments to the utility's As-Filed ASC.

Table 2.4-1: New Resource Additions Coming On Line *Prior to* the Exchange Period ($/MWh)

As-Filed FY 2012–2013 Exchange Period ASC				
Resource	**Group 1**	**N/A**	**N/A**	**N/A**
Expected On-Line Date*	12/01/2010			

Final Report FY 2012–2013 Exchange Period ASC				
Resource	**Group 1**	**N/A**	**N/A**	**N/A**
Expected On-Line Date*	12/01/2010			

*See ASC Summary Table 6.1 for details.

Table 2.4-2: New Resource Additions Coming On Line *During* the Exchange Period ($/MWh)

As-Filed FY 2012–2013 Exchange Period ASC				
Resource	**Group 2**	**N/A**	**N/A**	**N/A**
Expected On-Line Date*	10/01/2012			

Final Report FY 2012–2013 Exchange Period ASC				
Resource	**Group 2**	**N/A**	**N/A**	**N/A**
Expected On-Line Date*	10/01/2012			

*See ASC Summary Table 6.1 for details.

2.5 NLSL Adjustment

A new large single load (NLSL) is any load associated with a new facility, an existing facility, or an expansion of an existing facility that 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 ten average megawatts (aMW) or more in any consecutive 12-month period. 16 U.S.C. § 839a(13)(A)-(B).

By law, NLSLs and the associated resource costs in an amount sufficient to serve them are not included in utilities' ASCs. *See* 16 U.S.C. § 839c(c)(7)(A). BPA determines the cost of resources in an amount sufficient to serve NLSLs through the methodology provided in Endnote d of the 2008 ASCM and Section 2.6 of this report.

NLSLs are not determined in ASC review proceedings. NLSLs are identified through a separate process conducted by BPA's NLSL Staff tasked with implementing BPA's NLSL Policy. The ASC Review Process determines the cost of resources in an amount sufficient to serve the utility's NLSL and then excludes these costs from the utility's ASC.

For purposes of this Final ASC Report, BPA has determined that the large load identified as "Customer Group" below is an NLSL. The cost of resources in an amount sufficient to serve these potential NLSLs has been removed from the utility's ASC. PacifiCorp had the opportunity to rebut this presumption by providing BPA with information that established either: (1) that the identified load did not exceed 10 aMW in a 12-month period; or (2) that the load is fully or partially protected under the "contracted for or committed to" exemption in the Northwest Power Act. PacifiCorp submitted data identifying the customer group below as an NLSL and confirmed the customer load of 350,400 MWh. The Final ASC Report reflects BPA's final NLSL determination. To protect the confidentiality of the customer, the loads are identified by a pseudonym.

Table 2.5-1: New Large Single Loads Reviewed

As-Filed FY 2012–2013 NLSL Load Amount (MWh)	
NLSL	**Load**
"Customer Group"	0

Final Report FY 2012–2013 NLSL Load Amount (MWh)	
NLSL	**Load**
"Customer Group"	350,400

Table 2.5-2: New Large Single Loads That Begin Taking Power *Prior to* the Exchange Period

As-Filed FY 2012–2013 Exchange Period ASC				
Customer	**"Customer Group"**	**N/A**	**N/A**	**N/A**
Expected Start Date	N/A			

Final Report FY 2012–2013 Exchange Period ASC				
Customer	**"Customer Group"**	**N/A**	**N/A**	**N/A**
Expected Start Date	12/01/2010			

See ASC Summary Table 6.1 for details.

Table 2.5-3: New Large Single Loads That Begin Taking Power *During* the Exchange Period

As-Filed FY 2012–2013 Exchange Period ASC				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

Final Report FY 2012–2013 Exchange Period ASC				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

See ASC Summary Table 6.1 for details.

2.6 NLSL Resource Cost Determination and the Revised Implementation of Endnote d(3)

During a customer workshop held on October 6, 2009, BPA discussed with parties certain discrepancies that occurred in the calculation of the allocation of resource costs in an amount sufficient to serve NLSLs as defined in Endnote d(3) of the 2008 ASCM. In this workshop, BPA proposed an implementation of Endnote d(3) that avoided these discrepancies and streamlined the NLSL resource cost determination process. Following the workshop, BPA requested comments on its proposed NLSL resource cost calculation. On October 22, 2009, at the request of the workshop participants, BPA posted a revised NLSL Calculation Template that incorporated the changes BPA proposed at the October 6 workshop. The revised NLSL Calculation Template allowed parties to input their own resource data into BPA's NLSL model to see the practical impact of BPA's revised interpretation of Endnote d(3) on their respective ASCs.

After the close of the first comment period, BPA held another workshop on February 25, 2010, where BPA again discussed its proposed revised interpretation of Endnote d(3). On March 1, 2010, BPA requested additional comments from parties on the items discussed during the February 25 workshop, including the proposed NLSL resource cost calculation. After reviewing these comments, BPA published its proposed interpretation on April 21, 2010. *See Draft Interpretation and Proposed Implementation of Endnote d(3) of the 2008 Average System Cost Methodology,* available at http://www.bpa.gov/corporate/finance/ascm/meetings.cfm. A summary of BPA's interpretation follows below.

Endnote d(3) requires BPA to include in the NLSL resource cost calculation "an appropriate portion of general plant, administrative and general expense and other items not directly assignable . . ." *See* 18 C.F.R. § 301, End. d(3). The 2008 ASCM does not describe how BPA must determine the "appropriate portion" of cost categories not directly assignable, such as General Plant, A&G, General Plant Depreciation Expense, Property Taxes and Federal and State Employee Taxes. BPA proposes to revise its implementation of Endnote d(3) by conforming the ratios and allocation factors used in the NLSL Tab to the ratios and allocation factors used in the ASC Appendix 1 and ASC Forecast Model. The proposed changes were as follows:

Table 2.6-1: NLSL and Associated Resource Cost

Account	Previous Method	Revised Method
Plant Materials & Supplies	Direct Analysis	PTD
General Plant	Plant Capacity Ratio	*See* Functionalization Codes for Accounts 389–399.1
General Plant Depreciation Expense	None	GP
Administrative and General Expense (A&G)	Plant Capacity Ratio	*See* Functionalization Codes for Accounts 920–935; 404–406
Property Taxes	Direct Analysis	PTDG
Federal and State Employee Taxes	None	Labor

For both the Draft and Final ASC Reports, BPA adopted the aforementioned Draft Interpretation and Proposed Implementation of Endnote d(3) ("Endnote d(3) Interpretation") to calculate the resource costs in an amount sufficient to serve a utility's NLSL. Parties had an additional opportunity to comment on the Endnote d(3) Interpretation through the ASC Review Process by submitting comments on the Draft ASC Reports. No party submitted additional comments on the draft language of the Endnote d(3) Interpretation and, therefore, BPA will adopt the Endnote d(3) Interpretation as proposed and incorporate the language into the Final ASC Reports. Following publication of the Final ASC Reports, BPA will issue the final interpretation of Endnote d(3).

3 FILING REQUIREMENTS

3.1 Introduction

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act ("Northwest Power Act" or "Act"), 16 U.S.C. § 839c(c), established the Residential Exchange Program ("REP"). Under the REP, any Pacific Northwest utility interested in participating in the REP may offer to sell power to BPA at the average system cost of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at a rate established pursuant to sections 7(b)(l) and 7(b)(3) 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 grants to BPA's Administrator the authority to determine utility ASCs based on a methodology established in a public consultation proceeding.

See 16 U.S.C. § 839c(c)(7). In designing this methodology, the Act specifically requires the Administrator to exclude from ASC three categories of costs:

> (A) the cost of additional resources in an amount sufficient to serve any new large single load of the Utility;
>
> (B) the cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after the effective date of this Act; and
>
> (C) any costs of any generating facility which is terminated prior to initial commercial operation.

Id.

The first ASC Methodology was developed in consultation with regional parties in 1981. *See* 48 Fed. Reg. 46,970 (1983) ("1981 ASCM"). After three years of experience with the 1981 ASCM, BPA revised the ASC Methodology in 1984. *See* 49 Fed. Reg. 39,293 (1984) ("1984 ASCM"). After 23 years of experience under the 1984 ASCM, BPA commenced another consultation proceeding in 2007 to revise the 1984 ASCM. The goal of the consultation process was to update the ASC Methodology to reflect the significant changes that had occurred in the electric utility industry since 1984, modify the review procedures, and develop an administratively feasible ASC methodology that would be technically sound and comport with the Northwest Power Act. The end result of this consultation was the 2008 ASCM. In June of 2008, BPA filed the 2008 ASCM with the Federal Energy Regulatory Commission ("Commission") for the Commission's "review and approval." 16 U.S.C. § 839c(c)(7). On September 15, 2009, the Commission granted final approval to BPA's 2008 ASCM. No party contested the Commission's final ruling.

Consistent with BPA's ASC review procedures, BPA conducts a prescribed review of ASC Filings to ensure compliance with the 2008 ASCM. *See* Rules of Procedure at § 1. For more information regarding the 2008 ASCM, please refer to the Commission's final ruling and *2008 ASCM, 18 C.F.R Part 301* (2009) available at http://www.bpa.gov/corporate/finance/ascm/consultation.cfm and the *Final ASC Methodology ROD*, June 30, 2008, available at http://www.bpa.gov/corporate/pubs/RODS/2008.

3.2 ASC Review Process – FY 2012–2013

Utilities' ASCs are established in ASC Review Processes. The ASC Review Processes for FY 2012–2013 began on June 1, 2010, with the filing of ASCs by the following nine utilities: Avista, Clark, Franklin, Idaho Power, NorthWestern, PacifiCorp, Portland General, Puget, and Snohomish.[1] (Subsequent to the issuance of the Draft ASC Reports, Franklin withdrew from participation in the REP on March 22, 2011.) An "ASC Filing" consists of two Excel-based

[1] Grays Harbor PUD initially submitted an ASC Filing but subsequently withdrew it on June 17, 2010.

models developed by BPA (the Appendix 1 workbook and the ASC Forecast Model) and all supporting data and documentation provided by the utility.

Notice of the ASC Review Processes was provided on BPA's Web site. Concurrent with this notice, BPA posted the utilities' ASC Filings on BPA's secure REP Website. Parties interested in reviewing a utility's ASC had the opportunity to request access to the utility's ASC Filing by contacting BPA. Parties wishing to formally intervene in a utility's ASC proceeding could file an intervention by the date identified in BPA's ASC Review Process Schedule. Intervenors were afforded multiple opportunities to request data, submit comments, and raise issues with the utilities' ASCs. The filing utilities, in turn, were afforded opportunities to respond to requests for data, raise and respond to issues, and answer any questions relative to the Filings.

The Review Processes for FY 2012-2013 are complete. This Final ASC Report reflects BPA's review of the utility's ASC Filing and addresses, preliminarily, the issues and questions raised by the utility, intervenors, and BPA in the utility's ASC Review Process. The final ASC determinations and supporting justifications are published in the Final ASC Report for each participating utility and can be viewed at http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

3.3 Explanation of Appendix 1 Schedules

The Appendix 1 consists of a series of seven schedules and other supporting information that present the data necessary to calculate a utility's ASC. The schedules and supporting data are as follows:

1. Schedule 1 – Plant Investment/Rate Base (Rate Base)
2. Schedule 1A – Cash Working Capital Calculation (Cash Working Capital)
3. Schedule 2 – Capital Structure and Rate of Return (Rate of Return)
4. Schedule 3 – Expenses
5. Schedule 3A – Taxes
6. Schedule 3B – Other Included Items (Other Items)
7. Schedule 4 – Average System Cost
8. Purchased Power and Sales for Resale (3-Year PP & OSS Worksheet)
9. Load Forecast
10. Distribution Loss Calculation (Distribution Loss Calc)
11. Distribution of Salaries and Wages (Salaries)
12. Ratios
13. New Resources – Individual and Grouped
14. Materiality – Individual and Grouped
15. New Large Single Loads (NLSL Base New-Calc)
16. Tiered Rates

3.3.1 Schedule 1: Plant Investment/Rate Base

Schedule 1 of the Appendix 1 establishes the utility's rate base. The rate base computation begins with a determination of the Gross Electric Plant-In-Service's historical costs for Intangible, General, Production, Transmission, and Distribution Plant.

For exchanging utilities that provide electric and natural gas services, only the portion of common plant allocated to electric service is included. These values (and all subsequent values) are entered into the Appendix 1 as line items based on the FERC Uniform System of Accounts. Each line item (account) is functionalized to Production, Transmission, and/or Distribution/Other in accordance with the functionalizations prescribed in Table 1 of the 2008 ASCM.

The Net Electric Plant-In-Service is determined next by entering and functionalizing depreciation and amortization reserves in the Appendix 1 and adjusting the above-calculated Gross Electric Plant-In-Service for the depreciation and amortization reserves.

Total "Rate Base" is then determined by adjusting Net Electric Plant for Cash Working Capital (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits, Current and Accrued Liabilities, and Deferred Credits.

3.3.2 Schedule 1A: Cash Working Capital

Cash working capital is an estimate of investor-supplied cash used to finance operating costs during the time lag before revenues are collected. This approach (cash) ignores the lag in recovery of non-cash costs of service (depreciation), deferred taxes, and other items. The cash working capital concept is widely used by state commissions and is the basic premise of the Commission's proposed working capital formula. The purpose of working capital is to compensate a utility for funds used in day-to-day operations.[2]

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 into rate base. *See* 18 C.F.R. § 301, End. f.

3.3.3 Schedule 2: Capital Structure and Rate of Return

Schedule 2 calculates the utility's rate of return on the utility's Rate Base developed in Schedule 1.

The 2008 ASCM requires IOUs to use the weighted cost of capital (WCC) from their most recent state commission rate order. 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 described in Endnote b of the 2008 ASCM. *See* 18 C.F.R. § 301, End. b.

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[2] James C. Bonbright *et al*., Principles of Public Utility Rates 244 (2d ed. 1988).

The 2008 ASCM requires COUs to use a rate of return equal to the COU's weighted cost of debt.

3.3.4 Schedule 3: Expenses

This schedule represents operations and maintenance expenses for the production, transmission, and distribution of electricity. Each expense item is functionalized as outlined in Table 1 of the 2008 ASCM. Also included in Schedule 3 are 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. The sum of the items in Schedule 3 reflects the Total Operating Expenses for the utility.

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. COUs are allowed to include state taxes paid "in lieu" of property taxes. State income taxes, franchise fees, regulatory fees, and city/county taxes are accounted for in this schedule but are functionalized to Distribution/Other and therefore not included in ASC. Taxes and fees for each state listed are grouped together and entered as "combined" line items for Appendix 1 purposes.

Federal income taxes are included in ASC and are calculated, as applicable, in Schedule 2-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 for others (wheeling). The revenues in this schedule are deducted from the total costs of each utility.

3.3.7 Schedule 4: Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Capital Structure and Rate of Return, Expenses, 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 Base Period ASC ($/MWh).

<u>Contract System Cost:</u>
Contract System Cost (CSC) includes the utility's costs for production and transmission resources, including power purchases and conservation measures, which are includable in and subject to the provisions of the 2008 ASCM. CSC does not include the cost of serving a utility's NLSLs. CSC is the numerator in the ASC calculation.

<u>Contract System Load (MWh):</u>
Contract System Load (CSL) is the total regional retail load of a utility, adjusted for distribution losses and NLSLs. CSL is the denominator in the ASC calculation.

3.3.8 Purchased Power and Sales for Resale

Purchased Power is an Account in 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.

3.3.9 Load Forecast

Each utility is required to provide an eight-year forecast (FY 2010–2017) of its total retail load, as measured at the meter, and its qualifying residential and small-farm retail load, as measured at the retail meter. For the COUs only, the total retail forecast loads from the Exchange Period through 2017 are the load forecasts as determined by BPA under the Tiered Rate Methodology (TRM).

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.

3.3.10 Distribution Loss Calculation

Each utility is required to provide current distribution loss studies as described in Endnote e of the 2008 ASCM. *See* 18 C.F.R. § 301, End. e. The total retail and residential and small-farm load forecasts are adjusted for distribution losses (and NLSLs when appropriate).

3.3.11 Distribution of Salaries and Wages

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

3.3.12 Ratios

The Ratio tab calculates all functionalization ratios by assigning costs included in the utility's FERC Form 1 on a pro rata basis using values taken from the gross plant data (Schedule 1) for Production, Transmission, and Distribution/Other functions, and data taken from the salary and wage tab for Labor functions. For COUs, comparable information comes from the detailed salaries and wages data used in the utilities' financial reporting.

3.3.13 Major Resource Additions – Individual and Grouped

The 2008 ASCM allows a utility's ASC to adjust during the Exchange Period to reflect the addition or loss of a major new resource, subject to the materiality threshold of 2.5 percent. New resources are defined as any 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. 18 C.F.R. § 301.4(c)(3)(i)-(vii).

Utilities are required to provide forecasts of major resource additions and all associated costs with their ASC Filings. Utilities may include in their major new resource forecasts any new resources that are planned to begin commercial operation from the end of the Base Period (December 31, 2009) to the end of the Exchange Period (September 30, 2013).

To determine the effects of a major new resource addition or reduction on a utility's Exchange Period ASC, BPA performs one of the following calculations: (1) for new resources that are expected to be on line prior to the start of the Exchange Period, BPA projects the costs of the new resource forward to the midpoint of the Exchange Period; or (2) for new resources that are expected to be on line during the Exchange Period, BPA calculates the new resource cost as if the resource came on line at the midpoint of the Exchange Period.

Each resource that satisfies the minimum materiality threshold of 0.5 percent may be entered individually in the "New Resources – Individual" tab. Resources that do not meet the 2.5 percent materiality requirement independently may be grouped together with other resources within "New Resources – Grouped" to meet the 2.5 percent materiality requirement. The grouping and timing of materiality for new resource additions is discussed in Section 3.4 of this report.

3.3.14 New Large Single Loads

This tab calculates the cost of resources in an amount sufficient to serve an NLSL, which BPA must exclude from the utility's ASC pursuant to Northwest Power Act section 5(c)(7). 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 ten average megawatts (aMW) or more in any consecutive 12-month period. 16 U.S.C. § 839a(13)(A)–(B). By law, BPA must exclude from a utility's ASC the load associated with an NLSL and an amount of resource costs sufficient to serve such NLSL. *See* 16 U.S.C. § 839c(c)(7)(A). To determine the amount of resource costs to exclude from a utility's ASC, BPA follows the methodology described in Endnote d of the 2008 ASCM. *See* 18 C.F.R. § 301, End. d.

3.3.15 Tiered Rates

All exchanging COUs have the right to purchase power at BPA's Tier 1 rate by executing Contract High Water Mark (CHWM) Contracts with BPA. By signing the CHWM Contract, the utility agrees to limit the resources it will exchange in the REP. Under the CHWM Contract, the COU agrees to not include in its ASC the cost of resources necessary to serve the COU's Above-Rate Period High Water Mark (RHWM) load. The CHWM contracts require the cost of serving Above-RHWM loads to be calculated using a methodology similar to Endnote d of the 2008 ASCM. See Section 3.5 of this ASC Report for details.

Data input in this tab is used to calculate the cost of Tier 1 Power Purchases from BPA, and comes from BPA's Power Rates and Implementation Group (PFR). For background information and details, see http://www.bpa.gov/corporate/ratecase/TRM_Supplemental/.

3.4 Timing of Materiality for New Resource Additions

The 2008 ASCM, § 301.4(c)(4), states:

> Major resource additions or reductions that meet the criteria identified in paragraph (c)(3) of this section will be allowed to change a Utility's ASC within an Exchange Period provided that the major resource addition or reduction results in a 2.5 percent or greater change in a Utility's Base Period ASC. Bonneville will allow a Utility to submit stacks of individual resources that, when combined, meet the 2.5 percent or greater materiality threshold, provided, however, that each resource in the stack must result in a change to the Utility's Base Period ASC of 0.5 percent or more.

18 C.F.R. § 301.4(c)(4).

As noted by the foregoing, a utility's new resource additions or reductions must affect a utility's Base Period ASC by a minimum of 2.5 percent before the resources will be considered in the utility's ASC calculation. The 2008 ASCM, however, does not establish when BPA must make the materiality determination. The timing of the materiality calculation is crucial to determining whether a major new resource addition or reduction will be reflected in the utility's final ASC. The utility's ASC is constantly changing throughout the ASC Review Process as BPA and intervenors discover errors, omissions, and other adjustments to the utility's ASC Filing. As each adjustment is reflected in the utility's Base Period ASC, the materiality test for new resources also changes.

Previously, BPA made materiality determinations in the Final ASC reports. This approach ensured that the final ASC and new resource determinations were based on final decisions and the most up-to-date information. At the same time, however, determining materiality at this final stage of the ASC Review Process created eligibility problems with the new resource stacks provided by the utility. Under the 2008 ASCM, a utility may group or stack resources that individually affect a utility's ASC by 0.5 percent or more to meet the 2.5 percent materiality threshold. A stacked group of resources will not be added to the utility's ASC until the last resource in that stack comes on line. The grouping of resources together therefore has a significant impact on the timing of when a utility can expect to see its ASC changed for a new resource addition.

In the FY 2009 and FY 2010–2011 ASC Review Processes, significant changes occurred between the Draft ASC Reports and Final ASC Reports that affected the materiality test for several groups of resources. As a result of these changes, several groupings of new resources no longer met the 2.5 percent materiality threshold. However, because these changes occurred after the close of the comment period on the Draft ASC Reports, BPA had to regroup the utilities' new resources. BPA was faced with two options: it could exclude the resources that no longer met the materiality threshold, or regroup the resources such that they continued to meet the 2.5 percent requirement. BPA chose the latter option. BPA does not have access to the resource-specific information with which to make an informed regrouping decision, such as the likelihood that a certain set of projects will be completed and operational by their expected operational date. Another concern BPA had with making the regrouping decision was that it placed an issue that could significantly affect the utility's ASC in the hands of BPA without any input on the record from the exchanging utility.

To avoid this problem in the FY 2012–2013 ASC Review Processes, BPA proposed to change the timing of the materiality determination. During customer workshops held on October 6, 2009, February 25, 2010, and April 21, 2010, BPA explained its concern with the current timing of the materiality determination and the grouping/regrouping of new resources. After considering the public comments presented in the workshops, and the comments supplied by parties in response to BPA's letter dated March 1, 2010, BPA proposed to change the timing of the materiality decision from the Final ASC Report to the Draft ASC Report. BPA proposed this change in order to provide parties with one additional opportunity to comment on the ordering or stacking of new resource additions or reductions. BPA views this approach as the most advantageous means of determining materiality because, first, it does not place the burden on BPA to make new resource grouping decisions, and second, it ensures that utilities are permitted to submit to BPA the most advantageous regrouping of their eligible new resources.

In accordance with the foregoing, BPA made materiality determinations for all new resources submitted by each utility in its Draft ASC Report. To make these determinations, BPA provided the following instructions to the exchanging utilities at the outset of this ASC Review Process:

- The exchanging utility must include the costs and operating characteristics for each new resource addition.

- The utility must submit the resource additions (individual and/or grouped) that meet the materiality test(s) given the exchanging utility's base period costs.

- BPA will review each new resource addition submitted by the utility to determine the adequacy of costs and operating characteristics.

- BPA Staff will calculate the materiality of an exchanging utility's resources under the utility's adjusted Base Period ASC (Draft ASC) and forecast natural gas prices (BPA's BP-12 Initial Proposal forecast prices).

- BPA Staff will remove all resources and/or groups of resource additions that do not meet the materiality test(s) given the Draft ASC and forecast prices.

- BPA Staff will not unilaterally regroup resources.

- The Initial Proposal's (BP-12) natural gas price forecast will be the basis for the natural gas fuel costs used for new resource additions in both the Draft and Final ASC Reports.

- The exchanging utility will have the option to recommend a "regrouping" of resource additions that meet the materiality test(s).

- Exchanging utilities must submit the regrouped resource additions in their comments on the Draft ASC Report.

- Only resources that were reviewed by BPA and participants can be used in the regrouping process.

- BPA will make a determination of the new resource additions for the Final ASC Report.

- For the Final ASC Report, BPA will calculate the materiality of the utility's resources under the utility's final Base Period ASC.

The final grouping of new resources was determined after considering the filing utilities' and other parties' comments on the Draft ASC Report based on the foregoing instructions. No additional comments relating to new resources were filed, and thus the grouping or determination of new resources, if any, will not be changed from what was submitted for the Draft ASC Report. The materiality determinations provided herein are based on the utility's Base Period ASC as adjusted through the ASC Review Process and reflect the natural gas forecast from the BP-12 Rate Case Initial Proposal.

3.5 Rate Period High Water Mark ASC Calculation Under the Tiered Rate Methodology

Exchanging COUs have the right to execute CHWM Contracts in order to purchase power at BPA's Tier 1 rate. By signing the CHWM Contract, the utility agrees to limit the resources it will exchange in the REP. Under the 2008 ASC Methodology, COUs that execute CHWM Contracts are not allowed to include in their ASC the cost of resources used to meet their Above-RHWM loads.

CHWM Contracts require that the cost of resources used to meet Above-RHWM loads be calculated using a methodology similar to Endnote d of the 2008 ASCM.

During the FY 2012–2013 ASC Review Process, BPA proposed the following method for the Draft ASC Reports to determine the ASC of a COU that is participating in the REP.

- $$\text{RHWM ASC} = \frac{\text{Contract System Cost} - \text{NewRes\$}}{\text{Contract System Load} - \text{NewResMWh}}$$

- NewRes$ is the forecast cost of resources used to serve a customer's Above-RHWM Load. The costs included in NewRes$ will be determined using a methodology similar to Appendix 1, Endnote d, of BPA's 2008 ASC Methodology and as described below.

- NewResMWh is the forecast generation from resources used to serve a customer's Above-RHWM Load. For this Draft ASC Report, the NewResMWh has been set equal to the customer's Above-RHWM Load.

- For calculating both NewRes$ and NewResMWh, Existing Resources for CHWMs specified in Attachment C, Column D, of the Tiered Rate Methodology (*see* TRM-12S-A-03, September 2009, Attachment C) and purchases of power at Tier 1 rates from BPA are excluded.

A number of considerations are used in calculating the cost of serving Above-RHWM Loads using Endnote d of the 2008 ASCM:

- Types of resources to serve Above-RHWM Loads may be different from those resources used in the NLSL resource cost calculation and will be recognized in calculating RHWM ASC:

    - Power purchases less than five years' duration

- Total output of new resources may exceed Above-RHWM Load:

    - RHWM ASC does not specify removal of costs associated with this excess.

RHWM ASC calculation methodology:

- Set NewResMWh equal to Above-RHWM Load.
- NewRes$ = NewResMWh times Fully Allocated Cost (calculated using Endnote d).
- If output of material new resources fails to meet Above-RHWM Load, meet deficit with short-term (ST) market purchases at utility-specific market price.
- If output of new resources exceeds Above-RHWM Load, reduce ST market purchases by excess to the extent possible in Contract System Cost calculation.
- Sell any remaining surplus at utility-specific Sales for Resale price in the Contract System Cost calculation.

Parties had the opportunity to comment on the proposed methodology described above in comments on the Draft ASC Reports. No comments relating to the RHWM ASC were filed, and thus the proposed methodology as described above has been adopted and published in the Final ASC Reports.

3.6 ASC Forecast

Once the Base Period ASC is calculated, BPA uses the Excel-based forecasting model to escalate forward the Base Period ASC to the midpoint of the Exchange Period, which in this case is October 1, 2012. The ASC Forecast Model uses 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 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 both the Draft and Final ASC Reports, BPA updates the escalators in the ASC Forecast Model to be consistent with the escalators used in the BP-12 rate proceeding. For additional background on the determination of Exchange Period ASCs, see the 2008 ASCM. 18 C.F.R. § 301.4.

3.6.1 Forecast Contract System Cost

Forecast Contract System Cost ("FCSC") includes a utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which are includable in and subject to the provisions of the 2008 ASCM. BPA escalates Base Period costs to the midpoint of the FY 2012–2013 Exchange Period (October 1, 2012) to calculate Exchange Period ASCs. *See* 18 C.F.R. § 301.4(a). BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

3.6.2 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 utility-specific forecasts for the (1) price of long-term purchased power contracts and (2) long-term sales for resale price contracts, to value purchased power expenses and sales for resale revenue. *See* 18 C.F.R. § 301.4(b).

3.6.3 Forecast Contract System Load and Exchange Load

As a part of its ASC Filing, each utility is required to provide eight-year forecasts of its total retail load, as measured at the meter, and its qualifying residential and small-farm retail load, as measured at the retail meter. For the COUs only, total retail forecast loads for the Exchange Period through 2017 are the load forecasts as determined by BPA under the Tiered Rate Methodology. Also required is a current distribution loss study as described in the 2008 ASCM, Appendix 1, Endnote e. The total retail and the 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.

3.6.4 Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecast 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. *See* 18 C.F.R. § 301.4(e).

4 REVIEW OF THE ASC FILING

Pursuant to the 2008 ASCM, the Rules of Procedure for ASC Review Processes, and section 5(c) of the Northwest Power Act, BPA is responsible for reviewing all costs and loads used to establish ASCs for the REP. During this review and evaluation, various issues were identified by BPA or other parties. BPA's ASC determination is limited to specific findings on 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 the first published under the implementation of BPA's new Tiered Rate Methodology, including the Above-RHWM ASC calculation, further experience under the 2008 ASCM may result in BPA adopting a modified or different interpretation of the Methodology in future ASC reviews.

4.1 Resolved Issues

BPA raised the following issues and provided its proposed positions to PacifiCorp in BPA's August 24, 2010, Issue List and November 19, 2010, Draft ASC Report. PacifiCorp either accepted BPA's position or was able to work with BPA to resolve the issues. No other party commented on these issues. BPA considers the issues identified in this section as resolved.

4.1.1 Schedule 1: Plant Investment/Rate Base

4.1.1.1 Account 182.3 – Other Regulatory Assets

Issue:

Whether PacifiCorp's Direct Analysis supports its allocation of Account 182.3 – Contra Pension Reg Asset MMT & CTG – WY (Contract # 187601) and Reg Asset – Post-Ret MMT – WY (Contract #187623) to the Oregon, Washington, and northern Idaho jurisdictions (PNW) that are eligible to participate in the REP.

Parties' Positions:

PacifiCorp's initial Appendix 1 allocated Contract #187601 and Contract #187623 to PacifiCorp's PNW costs.

BPA's Position:

Costs associated with Contract #187601 and Contract #187623 are related to PacifiCorp's Wyoming jurisdiction and should not be included in PacifiCorp's PNW totals.

Evaluation 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 C.F.R. Pt. 301, Tbl. 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.

In response to BPA Data Request BPA-PA-FY12-31, PacifiCorp acknowledged that both Contract #187601 and Contract #187623 should be allocated to PacifiCorp's Wyoming jurisdiction and should not be included in PacifiCorp's PNW totals.

The allocation of Other Regulatory Assets should follow the jurisdiction in which they serve. BPA and PacifiCorp agreed that these assets should be allocated specifically to Wyoming and not included in PacifiCorp's PNW totals. (Tab Reg Assets, Rows 1139, 1146, 1147, and 1148.)

Decision:

The costs associated with Contract #187601 and Contract #187623 are related to PacifiCorp's Wyoming jurisdiction and will be removed from Account 182.3, Other Regulatory Assets.

Table 4.1.1-1: Account 182.3, Other Regulatory Assets (Contract #187601 and Contract #187623)

	Total	Production	Transmission	Dist/Other
As-Filed	61,185,432	53,144,103	2,813,752	5,227,577
Adjusted	62,173,298	53,680,319	2,876,214	5,616,865

4.1.1.2 Account 302 – Intangible Plant – Franchises and Consents

Issue:

Whether PacifiCorp's Direct Analysis supports its allocation of the Fort Hall Indian Reservation transmission right of way in Account 302, Intangible Plant – Franchises and Consents to Transmission.

Parties' Positions:

PacifiCorp's initial Appendix 1 allocated the transmission right of way on the Fort Hall Indian Reservation to Distribution/Other.

BPA's Position:

The $1,000,000 of rate base assigned directly to Idaho for the transmission right of way on the Fort Hall Indian Reservation should be allocated to Transmission.

Evaluation of Positions:

"S" and "SG" are allocation factors from PacifiCorp's Inter-Jurisdictional Cost Allocation Protocol (Protocol), which describes how the costs and wholesale revenues associated with PacifiCorp's generation, transmission, and distribution system will be assigned or allocated among its six state jurisdictions for purposes of establishing its retail rates. S refers to costs that are directly assigned to a state and is generally distribution-related. SG refers to the System Generation factor that allocates generation-related costs to states.

The 2008 ASCM requires a utility to functionalize its Accounts in accordance with Table 1 of the 2008 ASCM. *See* 18 C.F.R. Pt. 301, Tbl. 1. The Default functionalization of Account 302 is Direct Analysis. *Id.* If the utility does not perform a Direct Analysis, the functionalization is PTD. *Id.*

In response to BPA Data Request BPA-PA-FY12-01 and BPA's Issue List, PacifiCorp stated that the spreadsheet "Page 204-207" is from the 2009 FERC Form 1 and the Total Company number for Account 302 is derived from that account, cell K4. Only the following two methods of allocation may be used for this account:

Account 302 Franchise & Consents

- Distribution S
- Production, Transmission SG

However, despite the treatment of Account 302 in the Protocol, PacifiCorp and BPA agreed that the Account 302 amount related to the transmission right of way on the Fort Hall Indian Reservation should be functionalized to Transmission. *See* PacifiCorp's Response to BPA Issue List, August 24, 2010, at 1.

Decision:

The costs in Account 302, Intangible Plant – Franchises and Consents to Transmission associated with the Fort Hall Indian Reservation transmission right of way will be functionalized to Transmission.

Table 4.1.1-2: Account 302, Intangible Plant – Franchises and Consents

	Total	Production	Transmission	Dist/Other
As-Filed	67,239,409	66,239,409	0	1,000,000
Adjusted	67,239,409	66,239,409	1,000,000	0

4.1.2 Schedule 3: Expenses

4.1.2.1 Account 555, Purchased Power and Sales for Resale, Miscellaneous Items

Issue:

Whether the line items Accrual True-up, Line Loss Return, MWh Settlement, and Liquidated Damages reported in Account 555, Purchased Power, are actual transactions closed during the year.

Parties' Positions:

PacifiCorp's initial Appendix 1 included the Accrual True-up, Line Loss Return, MWh Settlement, and Liquidated Damages as Purchased Power transactions and appropriately recorded in Account 555.

BPA's Position:

BPA was unsure of the nature of Accrual True-up, Line Loss Return, MWh Settlement, and Liquidated Damages recorded in Account 555, Purchased Power.

Evaluation of Positions:

PacifiCorp stated that Accrual True-up represents the difference between actual settled amounts, as reflected in the individual line items of the FERC Form 1 page for the calendar year, and accruals during this same period. *See* PacifiCorp's Response to BPA data request BPA-PA-FY12-19, and Response to BPA Issue List, September 3, 2010, at 2. Purchased power expense for December activity is accrued at a high level at December 31 based on unverified data. *Id.* In mid-January similar entries are made in greater detail. *Id.* The December 31 accrual is reversed at this time. *Id*. The difference between these entries is the "accrual true-up." *Id.*

Line Loss Return is an accrual for the potential liability associated with disputes over the return of losses. *Id.* This is a valuation of the expense associated with the BPA settlement for return of transmission losses associated with the Hermiston generation facility. *Id.*

MWh Settlement is a liability associated with settlement for unmetered MWh. *Id*. This is a valuation of expenses associated with the BPA settlement for return of energy for over-delivery at Surprise Valley, return of losses to WAPA for the Thermopolis load, and a settlement with UAMPS to return energy to PacifiCorp for metering problems at Lehi. *Id.*

Liquidated Damages are damages associated with Naughton Plant overhaul delay. *Id.* This entry represents a credit received from Siemens for damages that occurred as a result of performing an overhaul on Naughton 3. *Id.* Purchased power expense was offset by this credit because it was determined that PacifiCorp had to go to the market to buy replacement power during the resulting outage. *Id.*

BPA accepted PacifiCorp's explanation of these line items and agreed that they should be reported in Account 555, Purchased Power.

Decision:

PacifiCorp's description that line items Accrual True-up, Line Loss Return, MWh Settlement, and Liquidated Damages reported in Account 555, Purchased Power, are actual transactions closed during the year is accepted. No adjustment will be made to this Account.

4.1.2.2 Account 555, Purchased Power

Issue:

Whether PacifiCorp correctly recorded Account 555, Purchased Power, in the 3-YEAR PP & OSS Worksheet.

Parties' Positions:

PacifiCorp's initial Appendix 1 had a hard-wired amount of $456,211,649 for Account 555, Purchased Power, in the 3-YEAR PP & OSS Worksheet, cell O7.

BPA's Position:

The amount reported in Account 555, Purchased Power, in the 3-YEAR PP & OSS Worksheet was incorrect.

Evaluation of Positions:

In response to BPA Data Request BPA-PA-FY12-13 and BPA's Issue List, PacifiCorp stated that the difference between the amount in Cell O7 of the 3-YEAR PP & OSS Worksheet ($456,211,649) and the value found in Cell R363 of worksheet pages 326–327 ($848,687,077) is the removal of Bookouts, Trade Purchases and REP payments. *See* PacifiCorp's Response to BPA Issue List, August 24, 2010, at 1. This amount was incorrectly entered in Cell O7. *Id.* The amount in Cell O7 should be the $848,687,077. *Id.* PacifiCorp states that correcting this error will not change the results because Cell O7 is not used. *Id.*

BPA agreed with PacifiCorp's correction. However, although PacifiCorp is correct in stating that the above values did not affect the Base Period Appendix 1, they did affect the ASC Forecast Model. Without correcting the above amounts, the ASC Forecast Model would incorrectly calculate the Exchange Period ASC.

Decision:

The amount reported in Account 555, Purchased Power, in the 3-YEAR PP & OSS Worksheet, cell O7, will be revised to $848,587,077.

4.1.3 Schedule 3B: Other Included Items

4.1.3.1 Account 407.3, Regulatory Debits

Issue:

Whether the amount included in Account 407.3, Regulatory Debits, is correct.

Parties' Positions:

In its initial Appendix 1, PacifiCorp reported $1,549,004 in Account 407.3, Regulatory Debits, and functionalized it to Distribution/Other.

BPA s Position:

An actual amount of $633,191 should be functionalized to Distribution/Other for Account 407.3, Regulatory Debits.

Evaluation of Positions:

The 2008 ASCM requires a utility to functionalize its Accounts in accordance with Table 1 of the ASCM. *See* 18 C.F.R. Pt. 301, Tbl. 1. The Default functionalization of Account 407.3 is Direct Analysis. *Id.* If the utility does not perform a Direct Analysis, the functionalization is PTD. *Id.*

In response to BPA Data Request BPA-PA-FY12-28 and BPA's Issue List, PacifiCorp stated that the $1,549,004 functionalized to Distribution/Other is incorrect. *See* PacifiCorp's Response to BPA Issue List, August 24, 2010, at 3. The amount that should be functionalized to Distribution/Other is $633,191. *Id.* $1,549,004 is the total company amount, and $633,191 is the amount allocated to PacifiCorp's PNW jurisdictions. *Id.*

BPA agreed that PacifiCorp incorrectly recorded the wrong amount in the Distribution /Other section of Account 407.3. The correct amount functionalized to Distribution/Other should be $633,191.

Decision:

The amount recorded in Account 407.3, Regulatory Debits, will be revised to $633,191.

Table 4.1.3-1: Account 407.3, Regulatory Debits

	Total	Production	Transmission	Dist/Other
As-Filed	633,191	0	0	1,549,004
Adjusted	633,191	0	0	633,191

4.1.3.2 Account 421, Miscellaneous Non-Operating Income

Issue:

Whether the amount reported in Account 421, Miscellaneous Non-Operating Income, is correct.

Parties' Positions:

In its initial Appendix 1, PacifiCorp reported $32,225,273 for Account 421, Miscellaneous Non-Operating Income, and functionalized it to Distribution/Other.

BPA's Position:

The correct amount that should be reported in Account 421, Miscellaneous Non-Operating Income, is $13,172,818.

Evaluation of Positions:

The 2008 ASCM requires a utility to functionalize its accounts in accordance with Table 1 of the ASCM. *See* 18 C.F.R. Pt. 301, Tbl. 1. The Default functionalization of Account 421 is Direct Analysis. *Id.* If the utility does not perform a Direct Analysis, the functionalization is PTD. *Id.*

In response to BPA Data Request BPA-PA-FY12-27 and BPA's Issue List, PacifiCorp stated that the $32,225,273 functionalized to Distribution/Other is incorrect. *See* PacifiCorp's Response to BPA Issue List, August 24, 2010, at 2. The amount that should be functionalized to Distribution/Other is $13,172,818. *Id.* $32,225,273 million is the total company amount, and $13,172,818 is the amount allocated to PacifiCorp's PNW jurisdictions. *Id.*

BPA agreed that PacifiCorp incorrectly recorded the wrong amount in the Distribution/Other section of Account 421. The correct amount functionalized to Distribution/Other should be $13,172,818.

Decision:

The amount recorded in Distribution/Other for Account 421, Miscellaneous Non-Operating Income, will be revised to $13,172,818.

Table 4.1.3-2: Account 421, Miscellaneous Non-Operating Income

	Total	Production	Transmission	Dist/Other
As-Filed	13,172,818	0	0	32,225,273
Adjusted	13,172,818	0	0	13,172,818

4.1.3.3 Account 456, Other Electric Revenues

<u>Issue:</u>

Whether PacifiCorp's Direct Analysis supports its functionalization of renewable energy credit (REC) sales in Account 456 to Distribution/Other.

<u>Parties' Positions:</u>

In its initial Appendix 1, PacifiCorp stated that the increase in Account 456, Other Electric Revenues, is related to $50,793,765 RECs in 2009 and functionalized it to Distribution/Other.

<u>BPA's Position:</u>

The increase in Other Electric Revenues in Account 456 is related to $50,793,765 (Total System) of REC sales in 2009, and should be functionalized to Production. The PNW allocation is $20,761,115.

<u>Evaluation of Positions:</u>

The 2008 ASCM requires a utility to functionalize its accounts in accordance with Table 1 of the ASCM. *See* 18 C.F.R. Pt. 301, Tbl. 1. The Default functionalization of Account 456 is Direct Analysis. *Id.* If the utility does not perform a Direct Analysis, the functionalization is to Production. *Id.*

As established in responses to BPA Data Requests BPA-PA-FY12-21 and BPA-PA-FY12-30, and BPA's Issue List, the increase in Other Electric Revenues in Account 456 is related to $50,793,765 of REC sales in 2009. Such sales in 2008 were zero. Please refer to BPA-PA-FY12-21_Attachment for details of Account 456.

- Account 456.1 Wheeling Revenues are allocated to each state and functionalized to Transmission.

- Account 456.21 revenues are from use of facility charges allocated to each state and functionalized to Transmission and Distribution/Other by the TD Ratio.

- Accounts 456.22, 456.23, 456.24, and 456.25 are distribution-related revenues assigned directly to each state and functionalized to Distribution/Other.

- Account 456.27 revenues are from renewable energy credits allocated to each state and should be functionalized to Production. Account 456.27 was incorrectly functionalized to Distribution/Other in the originally filed Appendix 1.

BPA and PacifiCorp's agreed that the description adequately clarified that the increase in Account 456, Other Electric Revenues, is related to $50,793,765 of REC sales in 2009. *See* PacifiCorp's Response to BPA Issue List, August 24, 2010, at 3.

Decision:

The increase in Account 456, Other Electric Revenues, is related to $50,793,765 (Total System) of REC sales in 2009 and will be functionalized to Production. The PNW allocation is $20,763,115.

Table 4.1.3-3: Account 456, Other Electric Revenues. Sales of Renewable Energy Credits

	Total	Production	Transmission	Dist/Other
As-Filed	20,763,115	0	0	20,763,115
Adjusted	20,763,115	20,763,115	0	0

4.1.3.4 Account 456, Other Electric Revenues: Demand Side Management Revenues

Issue:

Whether the functionalization of demand side management (DSM) revenues in Account 456, Other Electric Revenues, is correct.

Parties' Positions:

In its initial Appendix 1, PacifiCorp functionalized DSM revenues reported in Account 456, Other Electric Revenues, to Distribution/Other.

BPA's Position:

Revenue from DSM should be functionalized to Production.

Evaluation of Positions:

DSM entails actions that influence the quantity or patterns of energy consumed by end users. DSM-related costs are exchangeable and functionalized to Production. Therefore, any DSM-related revenue should be functionalized to Production.

The 2008 ASCM requires a utility to functionalize its Accounts in accordance with Table 1 of the ASCM. *See* 18 C.F.R. Pt. 301, Tbl. 1. The Default functionalization of Account 456 is Direct Analysis. *Id.* If the utility does not perform a Direct Analysis, the functionalization is to Production. *Id.*

In response to BPA Data Request BPA-PA-FY12-30 and BPA's Issue List, PacifiCorp stated that DSM revenue should be functionalized to Production. *See* PacifiCorp's Response to BPA Issue List, August 24, 2010, at 4.

BPA and PacifiCorp agreed that the proper functionalization of DSM Revenues is to Production.

Decision:

DSM revenue included in Account 456, Other Electric Revenues, will be functionalized to Production.

Table 4.1.3-4: Account 456, Other Electric Revenues
Demand Side Management Revenues

	Total	Production	Transmission	Dist/Other
As-Filed	13,590,164	0	0	13,590,164
Adjusted	13,590,164	13,590,164	0	0

4.1.3.5 Account 456, Other Electric Revenues: Miscellaneous Production Items

Issue:

Whether the functionalization of energy exchange credits, steam sales, fly ash/byproduct sales, and power sale and exchange agreements reported in Account 456, Other Electric Revenues, is correct.

Parties' Positions:

In its initial Appendix 1, PacifiCorp functionalized revenue from energy exchange credits, steam sales, fly ash/byproduct sales, and power sale and exchange agreements reported in Account 456, Other Electric Revenues, to Distribution/Other.

BPA's Position:

Revenue from energy exchange credits, steam sales, fly ash/by-product sales, and power sale and exchange agreements reported in Account 456, Other Electric Revenues, should be functionalized to Production.

Evaluation of Positions:

Energy exchange credits are related to the production of electricity, and therefore revenue from such credits should be functionalized to Production. Revenue from the sale of steam is production-related because the steam is produced at electric generating facilities. Fly ash is a residual from coal-fired generating plants, and therefore fly ash/byproduct sales should be functionalized to Production. Power sale and exchange agreements are related to the production of electricity, and therefore revenue from such agreements should be functionalized to Production.

The 2008 ASCM requires a utility to functionalize its Accounts in accordance with Table 1 of the ASCM. *See* 18 C.F.R. Pt. 301, Tbl. 1. The Default functionalization of Account 456 is Direct Analysis. *Id.* If the utility does not perform a Direct Analysis, the functionalization is to Production. *Id.*

In response to BPA Data Request BPA-PA-FY12-30 and BPA's Issue List, PacifiCorp stated that revenue from energy exchange credits, steam sales, fly ash/by-product sales, and power sale and exchange agreements should be functionalized to Production. *See* PacifiCorp's Response to BPA Issue List, August 24, 2010, at 5.

BPA and PacifiCorp agreed that the proper functionalization of revenue from energy exchange credits, steam sales, fly ash/byproduct sales, and power sale and exchange agreements is to Production.

Decision:

Revenue from energy exchange credits, steam sales, fly ash/by-product sales, and power sale and exchange agreements included in Account 456, Other Electric Revenues, will be functionalized to Production.

Table 4.1.3-5: Account 456, Other Electric Revenues
Miscellaneous Production Items

	Total	Production	Transmission	Dist/Other
As-Filed	7,082,831	0	0	7,082,831
Adjusted	7,082,831	7,082,831	0	0

4.1.3.6 Account 456, Other Electric Revenues: Miscellaneous Transmission Items

Issue:

Whether the functionalization of ancillary service revenue, phase-shifting equipment fees, revenue from interconnection and transmission studies, and maintenance charges for work on transmission facilities included in Account 456, Other Electric Revenues, is correct.

Parties' Positions:

In its initial Appendix 1, PacifiCorp functionalized ancillary service revenue, phase-shifting equipment fees, revenue from interconnection and transmission studies, and maintenance charges for work on transmission facilities reported in Account 456, Other Electric Revenues to Distribution/Other.

BPA's Position:

Ancillary service revenue, phase-shifting equipment fees, interconnection and transmission studies, and maintenance charges for work on transmission facilities reported in Account 456, Other Electric Revenues, should be functionalized to Transmission.

Evaluation of Positions:

Ancillary services are provided by a utility's transmission system, and therefore ancillary service revenue should be functionalized to Transmission. Phase shifters are equipment installed on a utility's transmission system, and therefore fees from other utilities for use of such equipment should be functionalized to Transmission. Revenue from interconnection and transmission studies should be functionalized to Transmission. Maintenance charges for work on transmission facilities should be functionalized to Transmission.

The 2008 ASCM requires a utility to functionalize its Accounts in accordance with Table 1 of the ASCM. *See* 18 C.F.R. Pt. 301, Tbl. 1. The Default functionalization of Account 456 is Direct Analysis. *Id.* If the utility does not perform a Direct Analysis, the functionalization is to Production. *Id.*

In response to BPA Data Request BPA-PA-FY12-30 and BPA's Issue List, PacifiCorp stated that ancillary service revenue, phase-shifting equipment fees, interconnection and transmission studies, and maintenance charges for work on transmission facilities should be functionalized to Transmission. *See* PacifiCorp's Response to BPA Issue List, August 24, 2010, at 5.

BPA and PacifiCorp agreed that ancillary service revenue, phase-shifting equipment fees, interconnection and transmission studies, and maintenance charges for work on transmission facilities are properly functionalized to Transmission.

Decision:

Ancillary service revenue, phase-shifting equipment fees, revenue from interconnection and transmission studies, and maintenance charges for work on transmission facilities included in Account 456, Other Electric Revenues, will be functionalized to Transmission.

Table 4.1.3-6: Account 456, Other Electric Revenues
Miscellaneous Transmission Items

	Total	Production	Transmission	Dist/Other
As-Filed	3,923,650	0	0	3,923,650
Adjusted	3,923,650	0	3,923,650	0

4.1.3.7 Account 456, Other Electric Revenues: Revenues not Specified ($250,000 or less)

Issue:

Whether the functionalization revenues not specified ($250,000 or less) reported in Account 456, Other Electric Revenues, is correct.

Parties' Positions:

In its initial Appendix 1, PacifiCorp functionalized all revenues not specified ($250,000 or less) reported in Account 456, Other Electric Revenues, to Distribution/Other.

BPA's Position:

A significant portion of revenues not specified ($250,000 or less) (Total System) reported in Account 456, Other Electric Revenues, is Production-related and should be functionalized as such.

Evaluation of Positions:

The 2008 ASCM requires a utility to functionalize its accounts in accordance with Table 1 of the ASCM. *See* 18 C.F.R. Pt. 301, Tbl. 1. The Default functionalization of Account 456 is Direct Analysis. *Id.* If the utility does not perform a Direct Analysis, the functionalization is to Production. *Id.*

In response to BPA Data Request BPA-PA-FY12-30 and BPA's Issue List, PacifiCorp stated that $12,304 are revenues from use of facility charges associated primarily with attachments on the distribution system, and $4,349 of that amount should be allocated to the PNW. *See* PacifiCorp's Response to BPA Issue List, August 24, 2010, at 6. PacifiCorp agreed that the remainder of the $164,726, of which $53,872 is allocated to the PNW, is Production or Transmission-related. *Id.*

BPA agreed with PacifiCorp's revised functionalization of revenues not specified ($250,000 or less) reported in Account 456, Other Electric Revenues.

Decision:

The amount of $4,349 of revenues not specified ($250,000 or less) reported in Account 456, Other Electric Revenues, will be functionalized to Distribution/Other, and the remainder will be functionalized to Production.

Table 4.1.3-7: Account 456, Other Electric Revenues
Revenues not Specified ($250,000 or less)

	Total	Production	Transmission	Dist/Other
As-Filed	58,211	0	0	58,211
Adjusted	58,211	53,872	0	4,349

4.1.3.8 Account 447, Sales for Resale

Issue:

Whether the amounts recorded for the line item Accrual True-up in Account 447, Sales for Resale, represent revenue from actual sales or are an accrual for future sales.

Parties' Positions:

PacifiCorp's initial Appendix 1 included Accrual True-up, recorded in Account 447, Sales for Resale, and represents revenue from actual sales.

BPA's Position:

BPA was unsure as to the nature of the line item Accrual True-up reported in Account 447, Sales for Resale.

Evaluation of Positions:

In response to BPA Data Request BPA-PA-FY12-20 and BPA's Issue List, PacifiCorp stated that this entry represents the difference between actual settled amounts, as reflected in the individual line items in the FERC Form 1 page for the calendar year, and accruals during this same period. *See* PacifiCorp's Response to BPA Issue List, August 24, 2010, at 2. Special sales for December activity are accrued at a high level at December 31 based on unverified data. *Id.* In mid-January similar entries are made in greater detail. The December 31 accrual is reversed at this time. *Id.* The difference between these entries is the "accrual true-up." *Id.*

BPA accepted PacifiCorp's description that Accrual True-ups are Sales for Resale transactions.

Decision:

PacifiCorp's description of the line item Accrual True-up in Account 447, Sales for Resale, is accepted and there will not be an adjustment for this issue.

4.1.3.9 Account 447, Purchased Power and Sales for Resale

Issue:

Whether PacifiCorp recorded the correct amount for Account 447, Purchased Power and Sales for Resale, in the 3-YEAR PP & OSS Worksheet.

Parties' Positions:

PacifiCorp's initial filing had a hard-wired amount of $643,321,157 for Account 447, Purchased Power and Sales for Resale, in the 3-YEAR PP & OSS Worksheet, Cell O8.

BPA's Position:

The amount recorded for Account 447, Purchased Power and Sales for Resale, in the 3-YEAR PP & OSS Worksheet, Cell O8, was incorrect.

Evaluation of Positions:

In response to BPA Data Request BPA-PA-FY12-14 and BPA's Issue List, PacifiCorp stated that the difference between the amount in Cell O8 of the 3-YEAR PP & OSS Worksheet ($643,321,157) and the value found in Cell P209 of worksheet pages 310–311 ($1,003,724,949) is the removal of Bookouts, Trade Purchases, and REP payments. *See* PacifiCorp's Response to BPA Issue List, August 24, 2010, at 1. This amount was incorrectly entered in Cell O8. *Id.* The amount in Cell O8 should be $1,003,724,949. *Id.* Correcting this error will not change the results because Cell O8 is not used. *Id.*

BPA agreed with PacifiCorp's correction. However, although PacifiCorp is correct in stating that the above values do not affect the Base Period Appendix 1, they do affect the ASC Forecast Model. Without correcting the above amounts, the ASC Forecast Model would incorrectly calculate the Exchange Period ASC.

Decision:

The amount reported in Account 447, Purchased Power and Sales for Resale in the 3-YEAR PP & OSS Worksheet, cell O8, will be revised to $1,003,724,949.

Table 4.1.3-9: Account 447 Purchase Power and Sales for Resale

	Total	Production	Transmission	Dist/Other
As-Filed		$643,321,157	0	
Adjusted		$1,003,724,949	0	

4.1.4 Schedule 4: Average System Cost

4.1.4.1 Total Other Included Items

Issue:

Whether the amounts recorded for Production, Transmission, and Distribution/Other sum to the total for Schedule 4, Total Other Included Items.

Parties' Positions:

PacifiCorp did not realize there was a math error in its initial Appendix 1 on Schedule 4.

BPA's Position:

PacifiCorp's initial Appendix 1 contained a math error on Schedule 4.

Evaluation of Positions:

In response to BPA Data Request BPA-PA-FY12-29 and BPA's Issue List, PacifiCorp stated that BPA should refer to the Company's responses to BPA-PA-FY12-27, filed July 16, 2010, and -28, filed July 16, 2010. *See* PacifiCorp's Response to BPA Issue List, August 24, 2010, at 3. The correction of the errors referenced in those responses will correct this error as well. *Id.*

BPA agreed that the corrections indicated in PacifiCorp's responses to BPA-PA-FY12-27 and 28 would correct the math error in Schedule 4.

Decision:

The Total Other Included Items line on Schedule 4 will be revised to correct the math error.

Table 4.1.3-10: Total Other Included Items

	Total	Production	Transmission	Dist/Other
As-Filed	507,282,045	408,022,508	29,559,671	87,836,508
Adjusted	507,282,045	449,519,690	33,481,454	24,280,045

4.2 Identification and Analysis of Unresolved Issues

In addition to the above resolved issues, BPA raised the following issues during the ASC Review Process, and PacifiCorp submitted its responses. No other party raised issues with, or commented on, the June 1, 2010, ASC Filing or PacifiCorp's Draft ASC Report.

Although a utility's state, county, or municipal regulatory bodies, or the Commission, may allow a particular functionalization to a specific account, BPA is not required to follow that 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* Rules of Procedure, § 3.2.2.

4.2.1 Schedule 1: Plant Investment/Rate Base

No direct adjustments.

4.2.2 Schedule 1A: Cash Working Capital

No direct adjustments.

4.2.3 Schedule 2: Capital Structure and Rate of Return

No direct adjustments.

4.2.4 Schedule 3: Expenses

No direct adjustments.

4.2.5 Schedule 3A: Taxes

No direct adjustments.

4.2.6 Schedule 3B: Other Included Items

No direct adjustments.

4.2.7 Schedule 4: Average System Cost

4.2.7.1 Distribution Losses

No direct adjustments. PacifiCorp submitted a distribution loss factor calculation of 2.7 percent.

4.2.7.2 Contract System Cost

CY 2009 Contract System Cost ($)

As-Filed		Adjusted	
Production	1,088,313,324	Production	1,046,883,138
Transmission	196,248,229	Transmission	192,448,292
Less NLSL	0	Less NLSL	0
Total	1,284,561,553	Total	1,239,331,429

4.2.7.3 Contract System Load

No direct adjustments.

CY 2009 Contract System Load (MWh)

	Total
As-Filed	21,112,995
Adjusted	21,112,995

4.2.7.4 Average System Cost

CY 2009 Average System Cost ($/MWh)

	Total
As-Filed	60.84
Adjusted	58.70

4.2.8 New Large Single Loads

4.2.8.1 Cost of Serving NLSLs

Issue:

Whether BPA assumed accurate MWh to attribute to a potential NLSL expected to come on line for PacifiCorp on December 1, 2010.

Parties' Positions:

PacifiCorp acknowledged that it will be providing electric service to a new data center being constructed by Facebook in Prineville, Oregon. The load is expected to reach 18 aMW in FY 2011 and 40 aMW in FY 2012. The NLSL load is included in PacifiCorp's load forecast.

BPA's Position:

The Facebook load in Prineville, Oregon will equal 18 aMW in FY 2011 and 40 aMW in FY 2012.

Evaluation of Positions:

Section 5(c)(7)(A) of the Northwest Power Act directs BPA to exclude from ASC the "cost of additional resources in an amount sufficient to serve any new large single load [NLSL] of the utility." 16 U.S.C. § 839c(c)(7)(A). To implement this provision, BPA developed Endnote d of the 2008 ASCM. In general, Endnote d identifies three methods for excluding from ASC the cost of resources sufficient to serve a utility's NLSL.

NLSL determinations are not made in the ASC review process. Instead, they are identified and made through a separate process conducted by BPA's NLSL Staff, which is tasked specifically with this responsibility. Although NLSLs are determined in another forum, BPA must establish in the Draft and Final ASC Reports where the cost of serving any potential NLSLs pursuant to the requirements in Endnote d(1)-(3) of the 2008 ASCM is removed. Parties to the ASC review processes must also be allowed an opportunity to review and comment on BPA's calculation.

PacifiCorp acknowledged (Letter September 23, 2010) that it will be providing electric service to a new data center being constructed by Facebook in Prineville, Oregon. The load is expected to reach 18 aMW in FY 2011 and 40 aMW in FY 2012.

For the Draft ASC Report, BPA has assumed that the Facebook load in Prineville, Oregon will equal 18 aMW in FY 2011 and 40 aMW in FY 2012 and will be used for determining ASCs for FY 2012–2013.

Decision:

The Facebook load in Prineville, Oregon will equal 18 aMW in FY 2011 and 40 aMW in FY 2012 and will be used for determining ASC for FY 2012–2013.

Table 4.2.8-1: New Large Single Loads Currently Under Review (MWh)

	Base Period	Prior to Rate Period Facebook (Phase 1)	Exchange Period Facebook (Phase 1 & 2)
As-Filed	0	0	0
Adjusted	0	157,680	350,400

4.2.9 New Resource Additions

No direct adjustments.

4.2.10 ASC Forecast Model

On May 3, 2010, BPA released its latest ASC Forecast Model to be used for the FY 2012–2013 ASC Review Processes. Following that release date but prior to the June 1 utility submissions, BPA and at least one other utility noted errors in the ASC Forecast Model. These errors, generally formula discrepancies, were minor and had no material effect on any utility's ASC. BPA notified the utilities of the inaccuracies and provided revisions to make the corrections. In addition, BPA modified the ASC Forecast Model to ensure that net Intangible Plant and net General Plant would not drop below zero. No utility objected to the corrections.

5 GENERIC ISSUES

5.1 Introduction

In addition to the above-noted issues specific to the determination of PacifiCorp's ASC, BPA raised the following issues that may be "generic" to all exchanging utilities. Participants to the ASC proceedings had an opportunity to comment on the Draft ASC Reports.

On September 3, 2010, the IOUs filed joint comments on the certain generic issues raised during the ASC proceeding and stated in BPA's Issue Lists. *See* Comments of the Pacific Northwest Investor-Owned Utilities Response to BPA Issue List for FY 2012–2013 ASC Filing: Generic Issues, September 3, 2010 (hereafter "IOU Comments").[3]

On February 25, 2011, Idaho Power, PacifiCorp, Portland General, and Puget filed separate comments on the Draft ASC Reports, incorporating by reference their previous comments made on September 3, 2010. *See* Comments of Idaho Power, dated February 25, 2011 ("IPC Comments"); Comments of PacifiCorp, dated February 25, 2011 ("PAC Comments"); Comments of Portland General Electric Co., dated February 25, 2011 ("PGE Comments"); and Comments of Puget Sound Energy, Inc. on the FY 2012–2013 Draft Average System Cost Report, dated February 25, 2011 ("PSE Comments").

For ease of reference, BPA will cite only to the parties' original September 3, 2010 (*i.e.*, "IOU Comments") comments unless reference to the utility's February 25, 2011, comments on the Draft ASC Report is warranted.

5.2 NLSL Issues

5.2.1 Rebuttal Presumption for NLSLs

Issue:

Whether BPA should create a rebuttable presumption that potential NLSLs are NLSLs for purposes of calculating ASCs in the Draft ASC Reports.

Parties' Positions:

The IOUs state that they do not have a position on whether BPA should create a rebuttable presumption that potential NLSLs are NLSLs for purposes of calculating ASCs in the Draft ASC Reports. *See* IOU Comments at 2.

[3] For purposes of this section, references to "IOUs" shall mean Avista Corporation, Idaho Power Company, PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc.

BPA's Position:

Draft ASC Reports should include a rebuttable presumption that potential NLSLs are NLSLs for purposes of calculating ASCs.

Evaluation of Positions:

Section 5(c)(7)(A) of the Northwest Power Act directs BPA to exclude from ASC the "cost of additional resources in an amount sufficient to serve any new large single load [NLSL] of the utility." 16 U.S.C. § 839c(c)(7)(A). To implement this provision, BPA developed Endnote d of the ASCM. In general, Endnote d identifies three methods for excluding from ASC the cost of resources sufficient to serve a utility's NLSL.

As discussed in Section 2.5 above, NLSL determinations are not made in the ASC review process. Although NLSLs are determined in another forum, BPA must establish in the Draft and Final ASC Reports the cost of serving any NLSLs pursuant to the requirements in Endnote d of the ASCM. Parties to the ASC Review Processes must also be allowed an opportunity to review and comment on BPA's calculation.

During BPA's review of utilities' ASC Filings for the FY 2012–2013 ASC Exchange Period, BPA identified a number of large utility loads that potentially met the statutory definition of an NLSL. REP Staff informed BPA's NLSL Staff of these loads. BPA's NLSL Staff began evaluating whether these loads met the statutory criteria for NLSLs. As of the publication of the Draft ASC Reports, BPA's NLSL Staff had not completed its evaluation. Consequently, for purposes of the Draft ASC Reports, BPA treated the large loads as NLSLs for ASC purposes, even though the formal NLSL determination process was not yet completed.

BPA believes that for purposes of the Draft ASC Reports, it is reasonable to create a rebuttable presumption that NLSLs identified in the ASC Review Process are NLSLs for purposes of calculating ASC. Utilities have the opportunity to rebut this presumption by establishing that the loads are not NLSLs in BPA's separate NLSL determination process.

BPA believes creating this presumption is reasonable because it ensures that all necessary Endnote d calculations can be made in the event BPA's NLSL Staff ultimately determines that the load is an NLSL. If it turns out that the suspect load is not an NLSL, then the calculation BPA performs in the Draft Report will have no impact on the utility's Final ASC. BPA also believes that the means of rebutting the presumption is reasonable because it ensures that the utility has an incentive to provide timely and complete load information to BPA's NLSL Staff.

As of the Final ASC Reports, BPA's NLSL Staff was able to obtain the necessary load data from the utilities in a timely manner. The final NLSL determinations have been completed for the Final ASC Reports, and the utilities' final ASCs are based on BPA's final NLSL determinations. Thus, no utility has been prejudiced as a result of BPA's decision to adopt this rebuttable presumption in the Draft ASC Reports.

Decision:

The Draft ASC Reports properly contained a rebuttable presumption that all potential NLSLs are NLSLs.

5.2.2 ASC Adjustments for NLSLs that Become Commercially Operational After the Base Period

Issue:

Whether BPA should adjust ASCs for NLSLs that come on line, or are determined to be NLSLs, after the Base Period.

Parties' Positions:

The IOUs argue that ASCs should be adjusted only for NLSLs that are identified and determined to be NLSLs prior to the beginning of the Exchange Period. *See* IOU Comments at 2-3. The IOUs do not support an approach that would allow BPA to make an adjustment to a utility's ASC during the Exchange Period based on a projected NLSL. *Id*.

BPA's Position:

Utilities' ASCs should be adjusted to reflect all NLSLs that were operating during the Base Period and new NLSLs that are projected to come on line between the end of the Base Period and the end of the Exchange Period.

Evaluation of Positions:

Section 5(c)(7)(A) of the Northwest Power Act states that ASCs shall not include the "cost of additional resources in an amount sufficient to serve any [NLSL] of the utility."
16 U.S.C. § 839c(c)(7)(A).

Section 3(13) of the Act defines an NLSL as:

> Any load associated with a new facility, an existing facility, or an expansion of an existing facility—(A) which is not contracted for, or committed to, as determined by the Administrator, by a public body, cooperative, investor-owned utility, or Federal agency customer prior to September 1, 1979, and (B) which will result in an increase in power requirements of such customer of ten average megawatts or more in any consecutive twelve-month period.

16 U.S.C. § 839a(13).

This statutorily prescribed exclusion has been reflected in BPA's 1981, 1984, and 2008 ASCMs through a prescribed treatment contained in ASCM footnotes or endnotes. Under the

2008 ASCM, the method for excluding resource costs sufficient to serve a utility's NLSL is found in Endnote d.

As noted above, NLSL determinations are not made in the ASC review process. Instead, they are made in a separate process by BPA's NLSL Staff. NLSL determinations nevertheless impact ASC determinations because BPA must establish in the ASC review process the cost of resources in an amount sufficient to serve any existing or potential NLSLs pursuant to the requirements in Endnote d of the ASCM.

The IOUs contend that if BPA has not made an NLSL determination prior to the Final ASC Reports, then any potential NLSLs should not be excluded in any manner from the utility's ASC. *See* IOU Comments at 2. They assert that because the Administrator has not made an NLSL determination, neither the load nor the cost of serving the load can be excluded from ASC *even if* BPA later determines during the Exchange Period that the load has become an NLSL. *Id.*

BPA disagrees. First, the IOUs are incorrect to assert that a final NLSL determination is necessary for calculating the cost of serving an NLSL. There are many instances where BPA may be able to make this calculation prior to the formal NLSL determination. For example, if BPA and an exchanging utility agree that a load is likely to become an NLSL after the Final ASC Reports are issued, but before the end of the Exchange Period, BPA and the utility can agree on the size of the load in order for BPA to determine the adjustment to the utility's ASC. Second, even if the utility and BPA are unable to agree on the size of a potential NLSL, it is still reasonable for BPA to make this estimate itself and then calculate the resource costs to exclude from ASC if and when the load becomes an NLSL. BPA is statutorily required to exclude from a utility's ASC the cost of resources sufficient to serve an NLSL. *See* 16 U.S.C. § 839c(c)(7)(A). If an NLSL is identified in a utility's service territory during an Exchange Period, BPA must be able to make an adjustment to the utility's ASC to implement the requirements set forth in section 5(c)(7) of the Northwest Power Act. Using a projected NLSL in the Final ASC report accomplishes this objective because it provides BPA with a predefined amount of resource costs to remove from the utility's ASC as a result of BPA's identification of an NLSL.

The IOUs object to this proposal, stating that it will "require BPA to make assumptions in the Final ASC Reports and Final Rate Case ROD regarding the amount of each utility's NLSLs, and the timing of any change in NLSL status." *See* IOU Comments at 2. These assumptions, the IOUs contend, "may or may not be accurate . . ." *Id.* The IOUs suggest that instead of projecting an NLSL and estimating its cost, BPA should do nothing to a utility's ASC if the suspect load becomes an NLSL during the Exchange Period. *Id.*

The IOUs' solution, however, creates more problems than it solves. The IOUs' approach would have BPA make *no* adjustment to the utility's ASC *even though* BPA has later determined that the suspect load has become an NLSL. This result is contrary to section 5(c)(7)(A), which directs BPA to exclude from ASC the costs of serving an NLSL. *See* 16 U.S.C. § 839c(c)(7)(A). The IOUs counter that this is appropriate because BPA does not know the precise size of the NLSL when estimating the cost to exclude from ASC. *See* IOU Comments at 2. However, BPA's inability to predict with absolute precision the size and timing of a potential NLSL does not excuse it from its statutory obligations to exclude prohibited loads and resource costs from

ASC. If BPA can make a reasonable estimate of the size of the NLSL, then it is reasonable for BPA to make a determination of the resources costs sufficient to serve such load. Simply ignoring the NLSL, as requested by the IOUs, would be inconsistent with both the purpose and the intent of section 5(c)(7)(A).

Moreover, the IOUs' concern with the "accuracy" of BPA's estimates of potential future NLSLs is overstated. Many aspects of the utilities' ASCs are based on BPA-generated forecasts. The entire ASC Forecast Model is based on historical Base Period Appendix 1 data, plus the cost of all new resource additions, which are then projected to the midpoint of the Exchange Period. BPA uses similar assumptions and forecasts for estimating the cost of resources serving NLSLs and the costs of resources included in each utility's ASC. Moreover, the accuracy of BPA's forecast of the amount of each utility's NLSLs, and the timing of any changes in NLSL status, will be heavily influenced by the accuracy of the data that the *utility* provides to BPA. If BPA's forecast of a new NLSL is inaccurate, it is likely due to the quality of information that BPA received from the utility.

The IOUs also claim that BPA's proposal creates an inconsistency in the way existing NLSLs are treated in the Base Period. *See* IOU Comments at 3. The IOUs note that, under BPA's proposal, a new NLSL would be excluded from the ASC calculation based on a projection of when the load will become an NLSL. *Id.* However, for existing NLSLs that appear in a utility's Base Period filing, the 2008 ASCM requires BPA to freeze the size of the NLSL at the existing level in the Base Period, even if it was known that the particular load was going to change significantly throughout the Exchange Period. *Id; see also* 2008 ASCM, Endnote d(3)(v). The IOUs contend that this approach would put utilities with new NLSLs at a significant disadvantage. *Id.*

BPA disagrees. BPA recognizes that, under its proposal, existing NLSLs in the Base Period will be determined based on CY 2009 data, while new NLSLs will be measured using data from the utility's most recent load forecasts. The IOUs are correct that, mechanically, an alternative way of calculating existing NLSLs would be to update the CY 2009 data with current load projections of the existing NLSLs. While this is an attractive alternative, Endnote d(3) of the ASCM does not permit this method. Endnote d(3)(v) states that the "Exchange Period NLSL load will equal the Base Period NLSL load." 18 C.F.R. § 301, End. d(3)(v). BPA interprets this language to mean that existing NLSLs in the Base Period will not be escalated (or decreased) from the load level present in the utility's Base Period filing. Thus, the 2008 ASCM does not permit BPA to make the real-time adjustment to existing NLSLs requested by the IOUs.

The IOUs claim that BPA's proposal disadvantages utilities with new NLSLs coming on line during the Exchange Period when compared to utilities with existing NLSLs in the Base Period. *See* IOU Comments at 3. The IOUs assert that this disadvantage occurs because new NLSLs will be based on more recent, and presumably higher, load forecasts. *Id.* This argument, however, is faulty. There is no inherent advantage or disadvantage to using more recent load data over using historic NLSL data. Both assumptions may be inaccurate when comparing them to the actual operation of the NLSL. For example, the size of an NLSL in the Base Period may be significantly higher than the actual operation of the NLSL during the Exchange Period.
In this scenario, the utility with the existing NLSL would be disadvantaged because BPA would

be excluding the costs of resources necessary to serve the NLSL at this higher level for the *entire* Exchange Period. Thus, there is no inherent advantage (or disadvantage) to BPA's proposal of using fixed historical values for existing NLSLs while using projected loads for new NLSLs.

Finally, BPA emphasizes again that a utility's ASC will *not* be affected by the NLSL calculations determined in this ASC Report *until* BPA's NLSL Staff has determined that the suspect load is an NLSL. Thus, if during the Exchange Period the forecast NLSL never becomes commercially operational or receives an appropriate CF/CT exemption, the resource costs BPA has calculated for such load will *not* be excluded from the utility's ASC. Conversely, if the forecast NLSL becomes commercially operational or does not receive an appropriate CF/CT exemption, the resource costs attributable to such load will be excluded from the utility's ASC.

Decision:

For potential NLSLs BPA believes will be operating before the end of the Exchange Period, BPA will make an estimate of the size of the NLSL and will calculate the resource costs to exclude from ASC if and when such load is determined to be an NLSL.

The specific ASC calculation BPA will perform for potential NLSLs is as follows: For a utility that BPA believes will have an NLSL that will operate before the end of the Exchange Period, BPA will calculate two ASCs. In the first ASC, BPA will assume the NLSL has not commenced operations. In the second ASC, BPA will reflect the operation of the NLSL.

Only when the NLSL becomes commercially operational will BPA adjust the utility's ASC to reflect BPA's NLSL determination.

5.2.3 Request for a Practical NLSL Determination Process

Issue:

Whether BPA should implement a workable and practical NLSL Determination process before an NLSL determination is made, and before such NLSL amounts are used in ASCs.

Parties' Positions:

Idaho Power, PacifiCorp, Portland General, and Puget each provided comments on the Draft ASC Reports requesting that BPA implement a fair and reasonable process in which to evaluate and determine NLSLs before NLSL determinations were made and used in ASCs. *See* IPC Comments at 1-2; PAC Comments at 1-2; PGE Comments at 1-2; and PSE Comments at 2.[4]

[4] The listed parties filed nearly identical comments on this issue. For ease of reference, BPA will be citing IPC's comments only.

BPA's Position:

The NLSL Determination Process is outside the scope of the ASC Review. BPA fully supports and strives to maintain an NLSL Determination Process that is consistent, transparent, efficient, fair, and reasonable. The above comments will be forwarded to appropriate BPA to take under advisement.

Evaluation of Positions:

Idaho Power, PacifiCorp, Portland General, and Puget suggest that BPA should set reasonable criteria to make an NLSL determination in two critical areas: (1) the historic data requirements that filing utilities need to supply in order to make determinations of CF/CT load, and (2) the degree of historic customer facility and load data necessary to make an NLSL determination. *See* IPC Comments at 1. These parties note that beginning in the late 1990s and up to the restart of the current ASC methodology in 2008, utility Appendix 1 filings were discontinued, which also eliminated the process for reviewing NLSL loads. *Id.* Due to this lack of process, in concert with standards for data retention, these utilities claim it is unreasonable now to expect utilities to provide decades-old customer load data. *Id.*

As stated throughout this ASC Report, BPA does not make final NLSL determinations as part of its review of a utility's ASC in the ASC Review Processes. Instead, BPA calculates the adjustment to a utility's ASC should BPA determine that the utility is serving an NLSL. The NLSL determination itself is made in a separate evaluation process conducted by BPA's NLSL Staff. Consequently, the concerns that Idaho Power, PacifiCorp, Portland General, and Puget have raised with BPA's NLSL determination process are outside of the scope of this ASC Report. BPA will forward these comments to BPA's NLSL Staff for their consideration.

Idaho Power, PacifiCorp, Portland General, and Puget appear to recognize that NLSL determinations are not made in the ASC Review Process. IPC Comment at 2. Nevertheless, these utilities contend that BPA must establish the removal of the costs of serving any potential NLSLs pursuant to the requirements in Endnote d(1)-(3) of the 2008 ASCM in the Draft and Final ASC Reports. *Id.* These utilities argue that parties to the ASC Review Processes must also be allowed an opportunity to review and comment on BPA's calculation. *Id.*

BPA concurs that, in determining the *costs* of resources to exclude from ASC because of an NLSL, utilities should have an opportunity to comment on BPA's calculation. BPA has provided that opportunity in this proceeding. First, BPA designed the Appendix 1 workbook and ASC Forecast model to include an NLSL worksheet ("NLSL Base New-Calc" tab) that automatically provides the utility with a calculation of the costs of resources necessary to serve any potential NLSLs. These models were provided to the utilities months before the Appendix 1 filings were due in the ASC Review Process. If a utility had any questions or concerns with the model's operation, it was free to provide BPA comments or questions. This opportunity to comment on the Appendix 1 models continued through the ASC Review Process. Thus, utilities were provided with multiple opportunities both before and during the ASC Review Process to ask BPA any questions and review BPA's proposed calculations of the costs sufficient to serve an NLSL.

Second, in the Draft ASC Reports, BPA provided parties with a draft calculation of the proposed adjustment to the utilities' ASCs due to an NLSL. BPA presented this calculation in section 2.5 of the Draft ASC Reports. Parties were free to review this calculation and provide BPA with any additional comments on this calculation in their comments on the Draft ASC Reports. As the foregoing discussion makes clear, BPA has provided parties to the ASC Review Processes "an opportunity to review and comment on BPA's calculation."

Decision:

The NLSL determination process is outside the scope of BPA's ASC Reviews. BPA has provided parties an opportunity to comment on BPA's calculation of the cost of resources to be removed from a utility's ASC due to an NLSL.

5.2.4 Treatment of Renewable Energy Certificates in NLSL and Above-RHWM Load Calculations

Issue:

Whether BPA should include purchases and sales of unbundled Renewable Energy Certificates (RECs) in the calculation of the costs of resources in an amount sufficient to serve NLSLs and Above-RHWM loads.

Parties' Positions:

The IOUs believe that revenue from the sale of unbundled RECs should be included as a credit to the costs of resources in an amount sufficient to serve an NLSL. *See* IOU Comments at 4. However, the IOUs do not believe that purchases of unbundled RECs should be included in the costs of resources in an amount sufficient to serve an NLSL and Above-RHWM loads. *Id*.

BPA's Position:

Neither the cost of unbundled REC purchases, nor the revenue from the sale of unbundled RECs, should be included in calculating the costs of resources in an amount sufficient to serve NLSLs or Above-RHWM loads.

Evaluation of Positions:

RECs are tradable certificates of proof measured in megawatthours (MWh) of energy produced by an "eligible renewable" resource. The market for RECs did not exist in a meaningful way when the 2008 ASCM was developed. RECs are a response to state renewable portfolio standards (RPS) that allow the transfer of the environmental attribute of a renewable resource between utilities. Eligible renewable resources produce one REC for each MWh of energy. RECs can be (1) kept by the owner of the renewable resource if the owner needs both the RECs and the power; (2) purchased or sold together to the same entity (bundled REC); or (3) purchased or sold separately (unbundled RECs). Energy produced by renewable resources where the RECs have been sold is considered the same as the energy produced by non-renewable resources. Because not all utilities have the ability to produce enough renewable resources to satisfy RPS requirements, REC purchases and sales are a way of using market mechanisms to get RECs to utilities where they are needed.

Currently, the majority of states and Washington, D.C. have some form of RPS, and there is discussion in Congress concerning development of national RPS. Oregon, Washington, and Montana have RPS standards in place, while Idaho does not. Pacific Northwest utilities are constructing a large amount of wind generation in response to state RPS requirements. In addition, several exchanging utilities currently sell excess RECs to other utilities, primarily in California. With RPS requirements increasing in Pacific Northwest states, and the likely need for additional RECs in California, the amount of REC sales and purchases in ASC filings is expected to grow over time.

In the ASC calculation, the cost of acquiring unbundled RECs is included in Contract System Cost as a purchased power expense. Revenues associated with the sale of unbundled RECs are accounted for in the sales for resale account and treated as a credit in Contract System Cost.

The complication associated with RECs in ASC calculations relates to the calculation of the cost of resources in an amount sufficient to serve NLSLs and Above-RHWM loads. BPA's NLSL methodology and Above-RHWM Load methodology are resource cost-based and MWh output-based methodologies respectively. These NLSL and Above-RHWM resource cost methodologies were developed before the treatment of RECs became an issue and are based on the MWh generation and certain fixed and variable costs of a subset of the utility's generating resources. Also included are the cost and MWh of long-term purchased power contracts greater than five years' duration. *See* 18 C.F.R. § 301, End. d(3) and Section 3.5 of this report.

In a response to BPA's Issue List for FY 2012–2013 ASC Filing: Generic Issues, the IOUs stated:

> The cost of serving an NLSL is tied to the costs of particular generation in each case. That generation may or may not create RECs, but there is no reason to assume that the costs of generation to serve an NLSL that does not create RECs must be artificially increased by the costs of purchasing RECs. The costs of purchasing RECs is appropriately considered on a portfolio-wide basis that reflects all generation included in a utility's ASC and should not be tied to the costs to serve a single load.

IOU Comments at 4.

BPA believes that RECs are an environmental attribute of eligible renewable resources. RECs can be separated from the renewable resources and sold to others if the RECs are not needed by the entity owning the renewable resource. Therefore, RECs are not true generating resources that produce power, but a resource-related cost for a utility that needs RECs to meet RPS mandates, and a resource-related benefit for entities that own eligible renewable resources but do not need the RECs. The purchase of unbundled RECs does not increase the quantity of MWh the purchasing utility has to serve load. Nor does the sale of RECs reduce the amount of MWh available to serve load. Because the purchase and sale of unbundled RECs does not change the quantity of MWh, BPA believes it is not reasonable to include unbundled REC purchases and sales in the generating resource cost-based NLSL/Above-RHWM resource cost methodology.

In addition, RPS requirements are legislative mandates which relate to a utility's total retail load. Unbundled REC purchases and sales are not tied to the cost or output of specific utility resources and purchases. Therefore, it would not be appropriate to try to tie the costs of unbundled REC purchases or the revenue from the sale of unbundled RECs to the resources included in the NLSL and Above-RHWM cost methodology.

Decision:

BPA will exclude the costs of unbundled REC purchases and exclude revenues from the sale of unbundled RECs from the calculation of the cost of resources in an amount sufficient to serve NLSLs and Above-RHWM loads.

5.3 Calculation of ASCs for COU Exchange Customers

5.3.1 Above-RHWM Obligation to Consult with Customers

Issue:

Whether BPA fulfilled its obligation to work with utilities to devise a method for determining the fully allocated unit costs of new resources used to meet above Above-RHWM load growth.

Parties' Positions:

The IOUs do not believe BPA has followed through with its commitment to determine the fully allocated unit costs of new resources used to meet above Above-RHWM load growth as stated in the 2008 ASCM ROD. *See* September 3, 2010, Comments of Avista Corporation, Idaho Power Company, PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc., in response to BPA's Request for Comments on "BPA Issue List – TRM Related Implementation for FY 2012–2013 ASC Filing" ("IOU TRM Comments").

BPA's Position:

BPA completed its obligation with the publication of the *Amendment of Contract High Water Mark Power Sales Contracts and Residential Purchase and Sale Agreements to Reflect Implementation of Tiered Rate Methodology ROD,* July 2009 ("CHWM Contract Amendment ROD").

Evaluation of Positions:

In response to BPA's Issue List, the IOUs state that a draft methodology for determining the "fully allocated unit costs of new resources used to meet above High Water Mark load growth" referenced in the draft ASCM ROD at page 69 should have been proposed by BPA for comment and, based on those comments, a final methodology for such determination should have been included in the final 2008 ASCM ROD. The IOUs argue that BPA has not to date fulfilled its commitment to work with utilities "to come up with an implementation of this area." *See* IOU TRM Comments at 2.

BPA disagrees. First, to be clear, BPA's response to the IOUs' request in the 2008 ASCM ROD is as follows:

> PSE suggests that a draft methodology for determining the "fully allocated unit costs of new resources used to meet above High Water Mark load growth" referenced in the Draft ROD at page 69 should be proposed by BPA for comment and, based on those comments, a final methodology for such determination should be included in the ASCM ROD. (PSE, ASC00 at 14.) BPA understands PSE's concerns, but does not think it needs to be addressed through a separate comment period and then included in the ASCM ROD. Instead, BPA will work with utilities to come up with an implementation of this area prior to the review period of the FY 2012–13 ASC filings.

2008 ASCM ROD at 87. Contrary to the IOUs' assertion, BPA has fulfilled this commitment through the CHWM Contract Amendment ROD. The CHWM Contract Amendment ROD specifically amends the CHWM power sales contracts to prescribe a formula for calculating a utility's RHWM ASC, which is designed, and defined, to exclude Above-RHWM costs and load.

The IOUs' apparent unfamiliarity with the CHWM Contract Amendment ROD process is surprising because BPA did not keep this process a secret. In January 2009, BPA initiated public processes to clarify language in the RD RPSA and the CHWM contracts. CHWM Contract Amendment ROD at 2. Workshops were held on January 15 and January 22, 2009, to introduce and discuss the two sets of proposed contract language. The first related to the definition and formula of Exchange Load for inclusion in the RPSA template. The second related to the optional language offered to each COU for amendment to Exhibit D of its CHWM contract and how the three major components of a COU's average system cost were calculated in order to derive a benefit level. *Id.* Both of the proposed sets of language were refined during the workshops and released for public review and comment. By letter dated January 30, 2009, BPA opened a three-week public comment period to receive feedback on proposed clarifying language for the CHWM contract and RD RPSA. *Id.* BPA received comments in these two processes from Clark County PUD ("Clark"), Snohomish County PUD ("Snohomish"), and a joint comment from Puget Sound Energy, Portland General Electric, PacifiCorp, Avista, and Idaho Power Company ("IOUs"). *Id.* Therefore, the IOUs' September 3, 2010, statement that BPA has not to date fulfilled its undertaking to work with utilities "to come up with an implementation of this area" is incorrect. All of the IOUs participated in the consultation process, which was completed with the issuance of the CHWM Contract Amendment ROD in July 2009. BPA has satisfied the commitment it made in the 2008 ASCM ROD.

Decision:

BPA fulfilled its obligation to work with utilities to devise a method for determining the fully allocated unit costs of new resources used to meet Above-RHWM load growth.

5.3.2 COU Conservation Cost Treatment and Rate Period High Water Mark ASCs

Issue:

Whether the costs of COU conservation programs should be included in the calculation of COUs' RHWM ASCs.

Parties' Positions:

The IOUs argue that to the extent COU-funded conservation results in reduced purchases at Tier 2 (Contract System Load is greater than RHWM), the costs of such conservation must be excluded from the COUs' RHWM ASC determination. *See* IOU TRM Comments at 5.

BPA's Position:

Conservation costs should be included in COUs' RHWM ASCs.

Evaluation of Positions:

Conservation costs funded by the utility are functionalized to Production in a utility's Contract System Cost. *See* 18 C.F.R. § 301.7(a).

In November 2008, BPA adopted the TRM, which is the methodology BPA uses to establish a two-tiered Priority Firm Power (PF) rate design applicable to firm requirements power service for COUs pursuant to CHWM contracts. The tiered rate design differentiates between the costs of service associated with the Tier 1 System Capability (Tier 1 Rates) and the costs associated with amounts of BPA power needed to serve any portion of a COU's Annual Net Requirements not served at a Tier 1 Rate (Tier 2 Rates). *See* CHWM Contract Amendment ROD at 1.

The CHWM Contract Amendment ROD stated that consistent with the philosophy of tiered rates, the CHWM contracts contained a provision that limited a COU's ability to participate in the REP. *Id.* at 1. The CHWM contracts provide, generally, that a COU signing such a contract agrees not to exchange new resources under the REP. *Id.* However, neither the RPSA nor the CHWM contracts described how REP benefits for a COU with a CHWM contract would be calculated. *Id.*

The ASCM defines the following process for determining COUs' ASCs:

(1) Use the RHWM System Resources as determined in the Tiered Rate Methodology.

(2) Determine the RHWM Exchange Load.

(3) Calculate the Utility's Contract System Cost as described in the ASC Methodology.

(4) Determine the fully allocated cost of resources used to meet Contract System Load that is not met by:
(i) The lesser of the Utility's RHWM or Forecast New Requirement, plus
(ii) Existing Resources for CHWM (as defined in the Tiered Rate Methodology).

(5) RHWM Contract System Cost = Contract System Cost minus fully allocated cost of resources (from paragraph (g)(4) of this section).

(6) RHWM Average System Cost = RHWM Contract System Cost (from paragraph (g)(5) of this section)/RHWM System Resource (from paragraph (g)(1) of this section).

18 C.F.R. § 301.4(g).

In July 2009, BPA issued the CHWM Contract Amendment ROD that clarified the method BPA would use to calculate Above-RHWM ASCs. In this ROD, BPA decided to use the same method to remove costs of serving Above-RHWM load from ASCs as used to remove the costs of serving NLSLs from ASCs. Therefore, the CHWM Contract Amendment ROD included the following formula for calculating a COU's RHWM ASC:

$$\text{RHWM ASC} = \frac{\text{Contract System Cost} - \text{NewRes\$}}{\text{Contract System Load} - \text{NewResMWh}}$$

Where:

NewRes$ is the forecast cost of resources (including purchased power contracts) used under this Agreement to serve «Customer Name»'s Above-RHWM Load. Such resources are exclusive of «Customer Name»'s Existing Resources for CHWMs as specified in Attachment C, Column D, of the TRM, and exclusive of purchases of power at Tier 1 Rates from BPA. The costs included in NewRes$ will be determined using a methodology similar to Endnote d of BPA's 2008 ASC Methodology.

NewResMWh is the forecast generation from resources (including purchased power contracts) used under this agreement to serve «Customer Name»'s Above-RHWM Load. Such resources are exclusive of «Customer Name»'s Existing Resources for CHWMs specified in Attachment C, Column D, of the TRM, and exclusive of purchases of power at Tier 1 Rates from BPA.

CHWM Contract Amendment ROD at 8.

BPA implements this language pursuant to the following simplified formula:

$$\text{RHWM ASC} = \frac{\text{Contract System Cost} - \text{NewRes\$}}{\text{Contract System Load} - \text{NewResMWh}}$$

NewResMWh = Above-RHWM Load

NewRes$ = Fully Allocated Costs × Above-RHWM Load

In general, the "Above-RHWM Load" is to be served by the utility's Post-2006 New Resources. If Post-2006 New Resources are insufficient to serve Above-RHWM Load, the remainder will be met with market purchases. The Fully Allocated Costs of Post-2006 New Resources are calculated using the same general method as used in Endnote d of the 2008 ASCM. Above-RHWM Load is calculated from the total retail load (TRL) forecast prepared by BPA. The TRL forecast assumes that conservation savings are included in the forecast.

For ASC purposes:

TRL MWh = RHWM MWh + Existing Resource MWh + Above-RHWM Load MWh

Above-RHWM Load MWh = TRL MWh – (RHWM MWh + Existing Resource MWh)

Because TRL assumes conservation savings, by definition, TRL cannot be served by conservation. Because Above-RHWM load is part of TRL, by definition, conservation cannot serve Above-RHWM load either. (*See* definition for Above-RHWM Load MWh.) BPA distributed and discussed the RHWM ASC formula shown above at an REP customer workshop on October 6, 2009. *See* http://www.bpa.gov/corporate/finance/ascm/meetings.cfm

Following the October 6, 2009, REP Customer Workshop, the IOUs suggested that BPA adopt the following general principle with respect to a COU's RHWM ASC if load growth is met with conservation rather than new generating resources:

> (i) to the extent COU-funded conservation results in reduced power purchases at Tier 1 (Contract System Load is less than RHWM), the costs of such conservation may be included in the COU's RHWM ASC, and
>
> (ii) to the extent COU-funded conservation results in reduced purchases at Tier 2 (Contract System Load is greater than RHWM), the costs of such conservation must be excluded from the RHWM ASC determination.

IOU TRM Comments at 3.

The IOUs further stated that under the foregoing general principle, the treatment of COU-funded conservation costs depends on the relationship between Contract System Load and RHWM. *Id.* Therefore, for purposes of the formula, the IOUs request that BPA treat conservation costs of the RHWM utility as follows:

1. The cost of any conservation of the RHWM utility funded by BPA should not be treated as conservation costs of the utility and should not be included in the RHWM utility's Contract System Cost.

2. If projected Contract System Load is greater than or equal to the utility's RHWM, then the conservation has not reduced the power purchased at Tier 1 rates, so all of the conservation is serving Tier 2 Load. *Id.* at 4. Therefore, all conservation costs of the RHWM utility are included in NewRes$.

3. If projected Contract System Load of the RHWM utility is less than the utility's RHWM, and (RHWM – Contract System Load) is greater than the amount of savings from conservation, then all of the conservation is serving Tier 1 loads, so no conservation costs are included in NewRes$.

4. If projected Contract System Load is less than the utility's RHWM, and (RHWM – Contract System Load) is less than the amount of savings from conservation, then the conservation costs must be prorated between Tier 1 Load reduction and Tier 2 Load reduction. Exchangeable (Tier 1) conservation costs shall equal the following:

    Tier 1 conservation costs = (RHWM – Contract System Load) ×
    conservation costs of utility amount of savings from conservation

    Accordingly, utility Tier 2 conservation costs included in NewRes$ can be determined as follows:

    utility conservation costs included in NewRes$ = conservation costs
    of utility − Tier 1 conservation costs

5. No adjustments for conservation are needed to the Contract System Load or NewResMWh.

Id. at 4.

The IOUs further contend that under the 2008 ASCM "the fully allocated unit cost of resources in excess of the resource amounts used to calculate [the utility's] Contract High Water Mark (CHWM)" is subtracted from the Contract System Cost. *Id.* at 5. The IOUs contend that the BPA Issue List dated August 30, 2010, describes the amount to be subtracted as follows: "the costs associated with new resources necessary to serve the COUs' Above-RHWM loads." *Id.* This proposal, the IOUs assert, focuses on load, which substantially deviates from the 2008 ASCM, which focuses on cost. *Id.* Moreover, the IOUs argue that this proposal fails to consider the comments previously submitted by the IOUs with respect to the treatment of conservation costs of RHWM utilities. *Id.* The IOUs argue that the approach in item 3 of the BPA Issue List dated August 30, 2010, addresses Total Retail Load and erroneously fails to recognize that only costs of resources not "in excess of the resource amounts used to calculate . . . [the utility's] Contract High Water Mark (CHWM)" may be exchanged by a COU with a CHWM contract. *Id.* The IOUs recommend that BPA abandon this approach in favor of the proposal submitted by the IOUs on November 6, 2009. *Id.*

BPA does not agree that its treatment of conservation costs in COUs' ASCs is improper or otherwise inconsistent with the ASCM. To begin with, the IOUs appear to be using the wrong version of the ASCM to support their argument. BPA believes the IOUs' argument is based on the following language from the ASCM ROD published in June of 2008:

> <u>G. ASC Determination for COUs that elect to execute Regional Dialogue HWM Contracts.</u>
>
> 1. Use the RHWM System Load as determined in the Tiered Rate Methodology (TRM) process.
> 2. Determine the RHWM Exchangeable Load (Residential/Small Farm Load).
> 3. During the Average System Costs Review process the Utility shall submit the data necessary to determine the fully allocated unit cost of resources in excess of the resource amounts used to calculate its CHWM.
> 4. Calculate the Utility's Total Unadjusted Contract System Cost (CSC) as described in the ASCM.
> 5. Calculate a load growth credit {(Current System Load minus RHWM system Load) * Unit costs from 3 above}.
> 6. Total Exchangeable Contract System Cost = Total Unadjusted CSC minus load growth revenue credit (from 5 above).
> 7. HWM Average System Cost = Total Exchangeable Contract System Cost / RHWM System Load

IOU TRM Comments at 1.

This language, however, was subsequently amended by BPA while the ASCM was being reviewed by the Commission. *See* BPA Comments on the Average System Cost Methodology, Dkt. EF08-2011-00, RM08-20-000, dated November 10, 2008. The Commission accepted BPA's changes and approved the ASCM on a final basis on September 4, 2009. *See* Sales of Electric Power to the Bonneville Power Administration, Revisions to Average System Cost Methodology, 74 Fed. Reg. 47,052-01 (2009). No utility protested this ruling. The language governing the determination of COUs' ASCs is provided in 18 C.F.R. § 301.4(g), as cited by BPA above. Thus, to the extent the IOUs rely on the language from the ASCM ROD to support their conclusion that BPA is acting inconsistent with the ASCM, the IOUs' objections are misguided because the language they rely on is no longer part of the ASCM.

Furthermore, BPA believes conservation costs should be included in COUs' RHWM ASCs for several reasons.

First, the load forecast included in the Appendix 1 and ASC Forecast Model is prepared by BPA, not the COUs. This load forecast is based on the TRL less a reduction in usage as a result of the COUs' conservation programs. Thus, BPA's forecast of COU load is net of, or excludes, the COUs' conservation programs. This is the same forecast assumption used by BPA to develop the COU load forecast in BPA's TRM rate proceeding. Because the COU load forecast used to determine ASC removes conservation savings, BPA believes the Above-RHWM Load cannot be served by conservation.

Second, the costs of BPA-funded conservation are included in the Tier 1 revenue requirement and the PF Exchange Rate. The inclusion of conservation in the calculation of COUs' ASCs provides consistent treatment of conservation costs between the BPA Tier 1 rate and the PF Exchange Rate.

After receiving and reviewing customer comments, BPA determined that because the TRL reflects the COUs' conservation savings, conservation cannot serve any TRL, including Above-RHWM Load.

Decision:

The costs of COUs' conservation programs will be included in the COUs' ASCs. This conclusion is consistent with the treatment of conservation costs for exchanging utilities under the TRM, CHWM Contract Amendment ROD and the 2008 ASCM.

5.4 Re-Bundling of Disaggregated New Resource Projects

Issue:

Whether, for ASC purposes, BPA should allow exchanging utilities the right to bundle projects that had been established as small projects for purposes of obtaining more favorable PURPA-published avoided cost rates. Bundling of these projects might increase the opportunity or likelihood of satisfying the materiality requirements for Major New Resource Additions under the 2008 ASCM.

Parties' Positions:

Idaho Power, PacifiCorp, and Portland General argue that projects that have been "disaggregated" for the purposes of obtaining favorable PURPA-published avoided cost rates should be permitted to be aggregated into a single project for ASC purposes. *See* IPC Comments at 2; PAC Comments at 2; and PGE Comments at 2.

BPA's Position:

The parties' comments do not challenge a specific decision or issue addressed in the Draft ASC Report. Further factual development is necessary for BPA to make an informed decision on this issue. The parties should raise this issue in a future ASC Review Process.

Evaluation of Positions:

The 2008 ASCM prescribes fixed materiality requirements for resources to qualify as Major New Resource Additions. *See* 18 C.F.R. § 301.4(c)(4). Absent meeting such thresholds, individual or grouped resources do not qualify as Major New Resource Additions under the 2008 ASCM.

Idaho Power, PacifiCorp, and Portland General contend that projects that have been "disaggregated" for the purposes of obtaining favorable PURPA-published avoided cost rates should be permitted to be aggregated into a single project for ASC purposes. *See* IPC Comments at 2; PAC Comments at 2; and PGE Comments at 2. These parties explain that in some circumstances wind projects have been "broken up" by the developer in order to obtain more favorable published avoided cost rates. *Id.* The parties cite to an investigation initiated by the Idaho Public Utilities Commission (IPUC) as evidence that developers may be disaggregating projects to utilize the published avoided cost rates. *Id.*

Although BPA understands the parties' concerns with the aggregation and disaggregation of new resources, it is unclear to BPA what this comment has to do with the decisions BPA has reached in the Draft ASC Reports. In raising this issue, the parties do not cite to any specific issue or decision BPA discussed in the Draft ASC Reports. Nor is BPA aware of any Issue List or other filing in these proceedings that addressed the concerns raised by the parties in their comments. As best BPA can tell, the parties' comment amounts to a request for BPA to make an advisory opinion on the ASC treatment of resources that have been aggregated or disaggregated for purposes of obtaining favorable PURPA rates. BPA declines to do so for two reasons.
First, inasmuch as the parties' comment is a "general" comment on BPA's review of the ASCs and is not aimed at challenging any specific decision or issue addressed in the Draft ASC Reports, BPA is not required to respond to the parties' comments. *See* Rules of Procedure at § 3.7.1.2 ("The Utility and parties must specifically identify the decision or statement from the Draft Utility ASC Report that is being addressed in the comments. Comments that contain generic statements regarding a Utility's ASC may not be considered by BPA.").

Second, BPA believes that resolution of this issue would be best served through additional factual development in a future ASC Review Process. There are simply too many factual unknowns for BPA to make an informed decision on whether BPA should consider aggregating or disaggregating PURPA resources under the ASCM. Although the parties cite the IPUC investigation, they provide no explanation why this investigation should require BPA to change the treatment of new resources in the ASC filings pending before BPA. The parties' comments also do not cite any specific errors in the findings BPA made in the Draft ASC Reports nor do they propose any specific changes to BPA's new resource decisions. For BPA to make a reasoned decision on this issue, parties should bring specific examples from a utility's ASC filing that demonstrate the problem they believe is being caused by the PURPA avoided cost rates. With this specific factual information in hand, BPA will have the necessarily factual context from which the agency can make an informed decision on this issue.

<u>Decision:</u>

Additional factual development is necessary for BPA to make an informed decision on the aggregation or disaggregation of PURPA resources for purposes of new resource determinations under the ASCM. BPA has insufficient factual information to make a decision on this issue at this time.

5.5 <u>Taxes</u>

5.5.1 ASC Appendix 1 – Schedule 3A Taxes – Property or In-Lieu Taxes

Issue:

Whether BPA should allow utilities the opportunity to directly assign costs of property or in-lieu taxes when calculating ASCs.

Parties' Positions:

Portland General, Idaho Power, and Puget argue that the 2008 ASCM should be modified to permit the direct assignment of property taxes and in-lieu taxes if the utility does not have a distribution line in the state in question. *See* PGE Comments at 2; IPC Comments at 3; PSE Comments at 2.

BPA's Position:

Under the 2008 ASCM, utilities are required to functionalize property or in-lieu taxes using the Production, Transmission, Distribution, and General Plant (PTDG) ratio.

Evaluation of Positions:

The 2008 ASCM requires that the "[f]unctionalization of each Account included in a Utility's ASC must be according to the functionalization prescribed in Table 1, Functionalization and Escalation Codes." 18 C.F.R. § 301.7(a). The 2008 ASCM further provides that a direct analysis 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." 18 C.F.R. § 301.7(a). Table 1 of the 2008 ASCM provides that Account 408.1 Property (or In-Lieu) taxes must be functionalized using the PTDG ratio. *See* 18 C.F.R. § 301, Tbl 1. Table 1 does not permit a direct analysis of Account 408.1. *Id.* The 2008 ASCM received final Commission approval on September 4, 2009, and was not challenged by any party. *See* Sales of Electric Power to the Bonneville Power Administration, Revisions to Average System Cost Methodology, 74 Fed Reg. 47,052-01 (Sep. 4, 2009).

In their comments on the FY 2012–2013 Draft ASC Reports, Portland General, Idaho Power, and Puget argue that the 2008 ASCM should provide a utility with the option to directly assign costs of property or in-lieu taxes if the utility does not have a distribution line in the state in question. *See* PGE Comments at 2; IPC Comments at 3; PSE Comments at 2.

BPA cannot accommodate the parties' request because the ASCM is patently clear on this issue: Account 408.1 Property or in-lieu taxes must be functionalized pursuant to the PTDG ratio. *See* 18 C.F.R. § 301, Tbl 1. Furthermore, Table 1 does not allow the utility to perform a direct analysis on Account 408.1. *Id.* Consequently, BPA is required to follow the plain and unambiguous terms of the 2008 ASCM. BPA has also previously responded to this argument in PSE's FY 2010-2011 Final ASC Report, which BPA incorporates by reference. *See* FY 2010-2011 Final ASC Report, Puget Sound Energy, at 31-33, dated July 14, 2009.

Portland General, Idaho Power and Puget appear to recognize that their request for a direct analysis of property or in-lieu taxes is inconsistent with the 2008 ASCM. *See* PGE Comments at 2; IPC Comments at 3; PSE Comments at 2. Thus, they request that BPA revise the ASCM to permit the direct assignment of costs of property or in-lieu taxes paid in states where the utility does not have a distribution function. *Id.*

BPA declines this request. Portland General, Idaho Power, and Puget had ample opportunity to challenge the 2008 ASCM while it was pending before the Federal Energy Regulatory Commission and after it was approved on a final basis. They chose not to challenge the ASCM, and the time for filing appeals has long since passed. BPA believes that the decisions it reached in the ASCM were proper and supported by the record developed before the agency during the regional consultation on the ASCM. BPA will not revisit these decisions as part of its review of utilities' ASCs.

<u>Decision:</u>

BPA will follow the plain, unambiguous terms of the 2008 ASCM and functionalize property and in-lieu taxes using the PTDG ratio.

5.5.2 Other Taxes

<u>Issue:</u>

Whether the ASCM should be modified to permit the inclusion of additional taxes in the calculation of a utility's ASC.

<u>Parties' Positions:</u>

Idaho Power, Portland General, PacifiCorp, and Puget incorporate by reference comments they filed in the ASCM consultation process and in the FY 2009 ASC Review Process on the functionalization of taxes. *See* IPC Comments at 3; PGE Comments at 2; PAC Comments at 2; PSE Comments at 2. These comments request that BPA include in the calculation of ASC taxes other than federal income taxes, state income and revenue taxes, out-of-state property taxes, and the Montana electric producers tax. *See* PSE Comment, Exhibit B at 1-2.

<u>BPA's Position:</u>

The ASCM does not permit the inclusion of the taxes requested by Idaho Power, Portland General, PacifiCorp, and Puget. BPA is properly implementing the 2008 ASCM as approved by FERC. To the extent these parties request BPA to change the 2008 ASCM, their comment is outside the scope of the ASC Review Process.

<u>Evaluation of Positions:</u>

Idaho Power, Portland General, PacifiCorp, and Puget incorporate by reference comments they have previously submitted to BPA on the "the functionalization of taxes." *See* IPC Comments at 3; PGE Comments at 2; PAC Comments at 2; PSE Comments at 2. These previously filed comments address four general areas: (1) taxes other than federal income taxes (general comment), (2) state and revenue taxes, (3) out-of-state property taxes, and (4) Montana electric producers tax. *See* PSE Comment, Exhibit B at 1-2.

BPA addressed the parties' concerns with the above four areas previously in the ASCM ROD. *See* 2008 ASCM ROD at 122-125. In addition, BPA addressed the parties' comments on property taxes above. *See* Section 5.5.1. Table 1 of the ASCM does not permit the inclusion of the taxes discussed by the parties. *See* 18 C.F.R. § 301, Tbl 1. The 2008 ASCM received final Commission approval on September 4, 2009, and was not challenged by any party. *See* Sales of Electric Power to the Bonneville Power Administration, Revisions to Average System Cost Methodology, 74 Fed. Reg. 47,052-01 (2009). To the extent the parties request BPA to modify the ASCM to allow these taxes into ASC, BPA declines to do so. BPA believes that the decisions it reached in the ASCM were proper and supported by the record developed before the agency during the regional consultation on the ASCM. BPA will not revisit these decisions as part of its review of utilities' ASCs.

<u>Decision:</u>

BPA will follow the plain, unambiguous terms of the 2008 ASCM. BPA will not modify the ASCM to permit the inclusion of other taxes.

6 FY 2012–2013 ASC

PacifiCorp's ASC for FY 2012–2013, prior to the addition of new resources and NLSLs taking power either before or during the Exchange Period, is $57.84/MWh. This result is based on adjustments made to PacifiCorp's ASC Filing.

Table 6.1 summarizes the possible ASCs that PacifiCorp may encounter depending on New Resource online dates and NLSL load determinations. The table displays both the prior to and during the Exchange Period and the drivers which impact ASCs over the FY 2012–2013 rate period.

Table 6.1: ASC Summary Table

Exchange Period ASC Summary Table				
	***Prior to* Exchange Period**		***During* the Exchange Period**	
	No New Resources	Group 1 only	Group 2 only	Both Groups 1&2
ASC w/o NLSL Load	$57.84	$60.51	$59.59	$62.26
ASC w/18 aMW NLSL Load	$57.70	$60.36	$59.45	$62.11
ASC w/22 aMW NLSL Load	$57.54	$60.18	$59.28	$61.93

7 REVIEW SUMMARY AND REQUEST FOR COMMENTS

The FY 2012–2013 ASC Review Processes are complete with the publication of the Final ASC Reports. BPA solicited and reviewed comments, if any, on the ASC Draft Reports of all other exchanging utilities for FY 2012–2013. After review of such comments, BPA completed final ASC determinations used to calculate REP benefits for each exchanging utility for FY 2012-2013.

BPA has resolved the issues set forth in Sections 4 and 5 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 Average System Cost for PacifiCorp for FY 2012 and FY 2013.

This Final ASC Report is BPA's determination of PacifiCorp's FY 2012 and FY 2013 ASC based on information and data provided by PacifiCorp, including comments in response to the Draft ASC Report, and based on the professional review, evaluation, and judgment of BPA's REP Staff.

8 ADMINISTRATOR'S APPROVAL

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

Issued in Portland, Oregon this 26th day of July, 2011.

/s/ Stephen J. Wright
Administrator and Chief Executive Officer

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BONNEVILLE POWER ADMINISTRATION

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