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

Public Utility District No. 1 of Snohomish County

July 2011

FY 2012–2013

FINAL
AVERAGE SYSTEM COST REPORT

FOR

Public Utility District No. 1 of Snohomish County

Docket Number: ASC-12-SN-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: **Public Utility District No. 1 of Snohomish County (Snohomish)**
2320 California Street
Everett, Washington 98201
http://www.snopud.com

Parties to the Filing:

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

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

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 Years (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 Snohomish'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 initial 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, it must have raised such issue in its comments on BPA's ASC Draft Reports. If a party failed to do so, the issue is waived for subsequent appeal.

2 AVERAGE SYSTEM COST SUMMARY

2.1 Snohomish Background

Snohomish County PUD (Snohomish) is a municipal corporation of the State of Washington, formed by a majority vote of the people for the purpose of providing electric and/or water utility service. Snohomish is the second-largest publicly owned utility in the Pacific Northwest and the twelfth-largest in the nation in terms of customers served.

The Everett, Washington-based public utility serves an area of approximately 2,200 square miles and serves approximately 318,500 electric customers.

Snohomish provides electric service to its customers over 6,046 miles of transmission and distribution lines. It owns generating capacity of 164 megawatts (MW) (two hydro projects and one cogeneration facility). In 2009, BPA supplied 87 percent of Snohomish's energy; the remainder was supplied by the Jackson Hydro Project and one other hydro project, a cogeneration plant and other small purchases.

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 Snohomish on June 1, 2010, including errata filed June 15, 2010 ("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	$309,328,014	$295,261,696
Transmission Cost	$45,134,843	$46,206,396
(Less) NLSL Costs	$0	$0
Contract System Cost (CSC)	**$354,462,857**	**$341,468,092**
Total Retail Load (MWh)	6,813,557	6,813,557
(Less) NLSL	0	0
Total Retail Load (Net of NLSL)	6,813,557	6,813,557
Distribution Losses	228,254	302,031
Contract System Load (CSL)	**7,041,811**	**7,115,588**
CY 2009 Base Period ASC (CSC/CSL)	**$50.34/MWh**	**$47.99/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 Snohomish filed on June 1, 2010, including errata filed June 15, 2010, and as adjusted by BPA for this Final ASC Report. If no new resources were to come on line, the ASC shown in Table 2.3-1 below would be Snohomish's ASC for the entire Exchange Period.

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 final 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 Snohomish'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

Date	June 1, 2010 As-Filed	July 26, 2011 Final Report
FY 2012–2013	49.10	48.05

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, including errata filed on June 15, 2010. 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* Exchange Period ($/MWh)

As-Filed FY 2012–2013 Exchange Period ASC				
Resource	**Group 1**	**Group 2**	**N/A**	**N/A**
Expected On-Line Date	1/10/2010	1/10/2010		
Delta*	-1.00	1.97		

Final Report FY 2012–2013 Exchange Period ASC				
Resource	**Group 1**	**Group 2**	**N/A**	**N/A**
Expected On-Line Date	1/10/2010	N/A		
Delta*	-1.37			

*The Delta is the incremental change in the ASC as new resources come on line. See Section 4.2.10 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	**N/A**	**N/A**	**N/A**	**N/A**
Expected On-Line Date				
Delta*				

Final Report FY 2012–2013 Exchange Period ASC				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On-Line Date				
Delta*				

*The Delta is the incremental change in the ASC as the new resources come on line. Snohomish does not have any major new resources coming on line during the Exchange Period.

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. Instead, 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.

Snohomish has no NLSLs on record or under review, and therefore no NLSL resource costs will be removed from its ASC.

Table 2.5-1: New Large Single Loads Under Review

As-Filed FY 2012–2013 NLSL Load Amount (MWh)	
NLSL(s)	**Load**
N/A	N/A

Final Report FY 2012–2013 NLSL Load Amount (MWh)	
NLSL(s)	**Load**
N/A	N/A

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	**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				

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				

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

During a customer workshop held on October 6, 2009, BPA Staff 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 Staff 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 <u>Introduction</u>

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 4, 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 the *2008 ASCM, 18 CFR 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 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 Web site. Parties interested in reviewing a utility's ASC had the opportunity to request access to the utility's 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 the issues and questions raised by the utility, intervenors, and BPA Staff during 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)

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

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, natural gas and water 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

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

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 orders. 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.

The 2008 ASCM requires COUs to use a rate of return equal to the COUs' 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).

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

Contract System Load (MWh):
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 a current distribution loss study 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 reports.

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. *See* 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 mid-point 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 the 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 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 resource 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 utilities. 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 Staff 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 Staff 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 Staff 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 Staff 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 Staff 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 Staff 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 utility’s 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 ASCM, COUs that execute CHWM Contracts are not allowed to include in their ASCs the cost of resources used to meet their Above-Rate Period High Water Mark (RHWM) load.

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.

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

- 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 ASCM 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 TRM (*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 ASC Forecast 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 TRM. 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 TRM, 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 <u>Resolved Issues</u>

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

4.1.1 Schedule 1: Plant Investment/Rate Base

4.1.1.1 Account 189 – Unamortized Loss on Reacquired Debt

<u>Issue:</u>

Whether Snohomish recorded the correct amount in Account 189, Unamortized Loss on Reacquired Debt.

<u>Parties' Positions:</u>

In its initial Appendix 1, Snohomish reported $0 for Unamortized Loss on Reacquired Debt for 2009.

BPA's Position:

Unamortized Loss on Reacquired Debt should be $20,862,518.

Evaluation of Positions:

In the initial Appendix 1, Snohomish reported Unamortized Loss on Reacquired Debt in Schedule 1, Rate Base, as zero.

In response to BPA Data Request BPA-SN-FY12-08 and BPA Issue List, Snohomish stated that Unamortized Loss on Reacquired Debt for 2009 should have been $20,862,518. *See* Snohomish's Response to BPA Issue List, August 24, 2010, at 3.

BPA agrees with Snohomish's explanation that the amount reported in Account 189, Unamortized Loss on Reacquired Debt, should be $20,862,518.

Decision:

BPA will correct the amount reported in Account 189, Unamortized Loss on Reacquired Debt, as noted in Table 4.1.1-1 below.

Table 4.1.1-1: Account 189 – Unamortized Loss on Reacquired Debt

	Total	Production	Transmission	Dist/Other
As-Filed	0	0	0	0
Adjusted	20,862,518	5,223,191	1,752,196	13,887,131

4.1.1.2 Account 303/304 – Intangible Plant – Miscellaneous

Issue:

Whether the totals reported in Account 303, Intangible Plant – Miscellaneous, are correct.

Parties' Positions:

Snohomish's initial Appendix 1 contained a difference between the Direct Analysis performed in supporting documentation workbook SnoPUD_ASC_Direct_Analysis_2009-2 working.xls, tab – Intangibles and the numbers reported in the Appendix 1.

BPA's Position:

The amounts recorded in Accounts 303, Intangible Plant, are incorrect.

<u>Evaluation of Positions:</u>

In Snohomish's initial Appendix 1, there was a difference between the Direct Analysis performed in supporting documentation workbook SnoPUD_ASC_Direct_Analysis_2009-2 working.xls, tab – Intangibles and the numbers reported in the Appendix 1.

In response to BPA Data Request BPA-SN-FY12-02 and BPA Issue List, Snohomish stated that it appears the numbers in the Intangible tab are correct and are backed by the Direct Analysis done by the District. The error likely occurred because the numbers entered in cells L18 – N18 on the Schedule 1 – Rate Base did not pull over correctly to the Appendix 1. *See* Snohomish's Response to BPA Issue List, August 24, 2010, at 1.

BPA agrees that Snohomish provided sufficient detail to support changes to Accounts 303, Intangible Plant.

<u>Decision:</u>

BPA will revise the amounts recorded in Accounts 303, Intangible Plant, as noted in Table 4.1.1-2 below.

Table 4.1.1-2: Account 303/304 – Intangible Plant – Miscellaneous

	Total	Production	Transmission	Dist/Other
As-Filed	64,206,728	13,483,413	6,420,673	44,302,642
Adjusted	64,315,144	7,876,302	9,686,528	46,752,314

4.1.1.3 Account 303 – Intangible Plant – Miscellaneous

<u>Issue:</u>

Whether Snohomish included the correct value for Account 303, Intangible Plant – Miscellaneous.

<u>Parties' Positions:</u>

In Snohomish's initial Appendix 1, the total reported in Account 303, Intangible Plant – Miscellaneous, was different than the amount shown for the same account on the Direct Analysis tab.

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

The amounts recorded in Accounts 303, Intangible Plant – Miscellaneous, are incorrect.

Evaluation of Positions:

In Snohomish's initial Appendix 1, the total reported in Account 303, Intangible Plant – Miscellaneous, was different than the amount shown for the same account in the Direct Analysis tab.

In response to BPA Data Request BPA-SN-FY12-02 and BPA's Issue List, Snohomish stated that the Direct Analysis functionalized amounts were correct, but not the amounts in the Appendix 1. *See* Snohomish's Response to BPA Issue List, August 24, 2010, at 1.

In response to Data Request BPA-SN-FY12-27 and BPA Issue List, Snohomish stated that the amount of $64,315,144 is correct. With the correction of amounts in Section 4.1.1.2, the total amount was also corrected.

See Snohomish's Response to BPA Issue List, August 24, 2010, at 9.

Decision:

BPA will revise the amounts recorded in Accounts 303, Intangible Plant – Miscellaneous, as noted in Table 4.1.1-3 below.

Table 4.1.1-3: Account 303 – Intangible Plant – Miscellaneous

	Total	Production	Transmission	Dist/Other
As-Filed	64,206,728	13,483,413	6,420,673	44,302,642
Adjusted	64,315,144	7,876,302	9,686,528	46,752,314

4.1.1.4 Account 310/316 – Steam Production

Issue:

Whether Snohomish recorded cogeneration costs in the correct FERC Account.

Parties' Positions:

In its initial Appendix 1, Snohomish stated that Accounts 311–315 and 501 on Snohomish's Generation System Balance sheet reflect assets and expenses related to its cogeneration plant. The definition in the Uniform System of Accounts defines this series of accounts as "Steam Production." Although this might have been intended to be used primarily for coal production, it is the closest match in the current FERC System of Accounts for cogeneration.

BPA's Position:

Cogeneration costs should be recorded in accounts consistent with FERC System of Accounts.

Evaluation of Positions:

The FERC System of Accounts requires that coal-fired production plant should be reported in Accounts 310–316. Other production plant is recorded in Accounts 340–346. Fuel expense for coal-fired plants is recorded in Account 501, and fuel expense for other production plant is reported in Account 547.

In response to BPA Data Request BPA-SN-FY12-06 and BPA Issue List, Snohomish PUD stated that Accounts 311–315 and 501 on Snohomish's Generation System Balance sheet reflect assets and expenses related to its cogeneration plant, which uses wood waste for fuel. The Uniform System of Accounts defines this series of accounts as "Steam Production." *See* Snohomish's Response to BPA Issue List, August 24, 2010, at 2. Although this might have been intended to be used primarily for coal production, it is the closest match in the current FERC System of Accounts for cogeneration. *Id.*

Because Accounts 311–315 and 501 are reserved for coal-fired power plants, BPA will reclassify the production plant amounts reported in Accounts 310–316 to 340–346, and the expense from Account 501 to 547.

Decision:

BPA will reclassify amounts from Accounts 310-316 to 340-346, and the expense from Account 501 to 547.

4.1.1.5 Rate Base Accounts

Issue:

Whether Snohomish included the correct values for certain Rate Base accounts.

Parties' Positions:

Snohomish's initial Appendix 1 stated that $33,345,000 represents the principal payments that were due on December 1, 2009, for both the Generation System and the Electric System.

BPA's Position:

BPA questions whether the amount indicated for principal payments within the Appendix 1 filing agrees with the annual report.

Evaluation of Positions:

Pursuant to Snohomish's response to Data Request BPA-SN-FY12-21, the submitted schedule includes principal payments of $33,345,000. The financial statements for 2009 indicate that long-term debt decreased $18,900,000 in 2009 due to principal repayments. *Id.*

In response to Data Request BPA-SN-FY12-32 and BPA Issue List, Snohomish stated that $33,345,000 represents the principal payments that were due on December 1, 2009, for both the Generation System and the Electric System and that the annual report amount was net of $13,100,000 sale of Series 2009 Water System Revenue Bonds. *See* Snohomish's Response to BPA Issue List, August 24, 2010, at 11.

BPA believes that Snohomish adequately addressed the issue and that no change is necessary.

Decision:

The amount indicated for principal payments within the Appendix 1 agrees with the annual report. No change is necessary.

4.1.2 Schedule 2: Capital Structure and Rate of Return

4.1.2.1 Rate of Return

Issue:

Whether Snohomish's calculation of Rate of Return is correct.

Parties' Positions:

In its initial Appendix 1, Snohomish reported a weighted cost of capital (WCC) of 5.27 percent.

BPA's Position:

The correct WCC is 5.33 percent.

Evaluation of Positions:

To determine the return calculation, the 2008 ASCM requires an IOU to use the WCC from its most recent State Commission Rate Order with a Federal income tax adjustment. 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 descried in Endnote b of the 2008 ASCM. *See* 18 CFR § 301, End. b. For a COU, the rate of return is equal to the COU's weighted cost of debt times total rate base as determined in Schedule 1. *Id.*

In response to BPA Data Request BPA-SN-FY12-21 and BPA's Issue List, Snohomish provided an Excel file (weighted cost of capital.xls) which more clearly outlines the calculation of its 2009 WCC and reconciles to the numbers in the 2009 annual report. *See* Snohomish's Response to BPA Issue List, August 24, 2010, at 2. The figure shown is slightly higher (5.33 percent) than the amount originally included in the Appendix 1 (5.27 percent). The 5.27 percent calculation included some short-term debt which has been excluded from the 5.33 percent calculation. *Id.*

BPA believes that Snohomish adequately addressed the issue and that the 2009 weighted cost of capital should be 5.33 percent.

Decision:

BPA will revise the weighted cost of capital to 5.33 percent.

4.1.3 Schedule 3A: Taxes

4.1.3.1 408.1 – Unemployment Taxes

Issue:

Whether Snohomish included the correct value for Account 408.1, Unemployment Tax.

Parties' Positions:

Snohomish stated that the unemployment tax is included in Account 926105, which is reported on Schedule 3.

BPA's Position:

Snohomish reported unemployment tax twice in its initial Appendix 1.

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 2008 ASCM provides one method for the functionalization of Account 408.1, Unemployment Taxes. The default functionalization is the Labor ratio. *Id.*

In response to BPA Data Request BPA-SN-FY12-31 and BPA Issue List, page 4, Snohomish stated that the unemployment tax is included in Account 926105. Upon further review, this amount had already been included in Schedule 3 and should be removed from Schedule 3A. *See* Snohomish's Response to BPA Issue List, August 24, 2010, at 10.

BPA agrees with the response by Snohomish and will remove the amount of $134,472 in Account 408.1, Unemployment Taxes, from the 2009 Appendix 1.

Decision:

BPA will remove Unemployment Taxes from Account 408.1.

Table 4.1.3-1: Account 408.1 – Unemployment Taxes

	Total	Production	Transmission	Dist/Other
As-Filed	135,472	23,513	4,408	107,552
Adjusted	0	0	0	0

4.1.4 Purchased Power and Sales for Resale

4.1.4.1 Account 555 – 3-YEAR PP & OSS Work Sheet: Long-Term Purchased Power

Issue:

Whether $18,000,000 relating to the Enron Contract should be removed from Account 555 in Appendix 1, 3-Yr PP & OSS Tab.

Parties' Positions:

Snohomish's initial Appendix 1 included $18,000,000 relating to the Enron Contract in Purchase Power Base Period Minus 2 in Account 555 on the 3-Yr PP & OSS Tab.

BPA's Position:

The $18,000,000 Enron Contract amount should be removed from Purchase Power Base Period Minus 2 in Account 555 on the 3-Yr PP & OSS Tab.

Evaluation of Positions:

In response to BPA Data Request BPA-SN-FY12-12 and BPA Issue List, Snohomish stated that the amount in Purchased Power Base Period Minus 2 should not include $18,000,000 relating to the Enron Contract. *See* Snohomish's Response to BPA Issue List, August 24, 2010, at 5.

Including this amount in the Base Period Minus 2 does not affect the base ASC. However, it does affect the calculation of the percentage spread. This spread is used in the Forecast Model.

Decision:

BPA will remove the $18,000,000 Enron Contract amount from Base Period Minus 2 in the Appendix 1 Base Year 2009 filing per Table 4.1.4-1 below.

Table 4.1.4-1: Account 555 – 3-YEAR PP & OSS Work Sheet: Long-Term Purchased Power, Purchased Power – Base Period − 2

	Account	Amount
As-Filed	555 - LF	$230,445,459
Adjusted	555 - LF	$212,445,459

4.1.5 Distribution Loss

4.1.5.1 Distribution Loss Percentage

Issue:

Whether Snohomish included the correct value for distribution losses.

Parties' Positions:

Snohomish's Appendix 1 included a distribution loss factor of 3.35 percent.

BPA's Position:

Snohomish's distribution loss factor should be 4.43 percent.

Evaluation of Positions:

Section 301.4(d) of the 2008 ASCM requires the utility to include with its ASC filing "a current distribution loss analysis as described in Endnote e of [the] Appendix 1 . . .." *See* 18 C.F.R. § 301.4(d). Endnote e outlines three methods for determining distribution losses, one of which is the submission of a current distribution loss study. *See* 18 C.F.R. § 301.4.

In response to BPA Data Request BPA-SN-FY12-10 and BPA Issue List, Snohomish provided a PDF attachment(s) entitled "2009 annual report excerpt.pdf," which shows retail sales for 2005-2009 and spreadsheet "trl & dist losses.xls." *See* Snohomish's Response to BPA Issue List, August 24, 2010, at 4. The resulting distribution loss factor is 4.43 percent.

BPA will use the updated distribution loss study.

Decision:

BPA will revise the distribution loss factor to 4.43 percent.

4.2 Identification and Analysis of Unresolved Issues

In addition to the above, BPA raised the following issues during the ASC Review Process, and Snohomish submitted its responses. No other party raised issues with or commented on Snohomish's June 1, 2010, ASC Filing or Snohomish's Draft ASC Report. Snohomish also raised one issue, and BPA provided a response. Clark submitted comment to BPA on this same issue in its respective docket.

Although a utility's state, county, or municipal regulatory bodies or FERC may allow a particular functionalization to a specific account, BPA is not required to follow 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 adjustment.

4.2.4 Schedule 3: Expenses

No direct adjustment.

4.2.5 Schedule 3A: Taxes

4.2.5.1 Account 408.1 – Schedule 3A – Taxes: State and Other: Property Taxes

Issue:

Whether Washington state taxes paid by COUs under RCW 54.28.080 are in lieu of property taxes and were properly accounted for and functionalized.

Parties' Positions:

Snohomish recorded in-lieu property taxes in Account 408.1, Other Taxes, and functionalized them to Distribution/Other.

BPA's Position:

Taxes paid under RCW 54.28.080 are payments in lieu of property taxes and should be functionalized using the PTDG ratio. Taxes paid under RCW 54.28.080 should be recorded on the "Property or In-Lieu" line on Schedule 3A of the Appendix 1.

Evaluation of Positions:

Endnote c of the ASCM states that

> A tax-exempt Utility may include in-lieu taxes up to an amount that is

> comparable, for each unit of government paid in-lieu taxes, with taxes that would have been paid by a non-tax exempt utility to that unit of government. In no event shall the Utility's regional total be greater than the actual amount paid or the amount used to determine the total revenue requirement. In-lieu taxes shall be functionalized according to the PTDG ratio.

18 C.F.R. § 301, End. c.

Chapter 1, Laws of 1931, authorized the establishment of public utility districts in Washington. *See* Wash. Attorney General Opinion (AGO) 1964 No. 79 (January 22, 1964). Ten years later, Chapter 245, Laws of 1941, created several laws requiring the state tax commission to collect payments from public utility districts and to return the funds collected to county treasurers. *Id*. One such law requiring the collection of payments from public utility districts is the Public Utility District Privilege Tax, found at RCW 54.28. The Washington Attorney General, in an opinion issued on August 13, 1963, describes the tax found in RCW 54.28.080 as a tax in lieu of property tax:

> Thus, under RCW 54.28.080, supra, the public utility district is not being taxed. Rather it is paying, in lieu of the tax that would be imposed were the public utility district's properties on the rolls, an amount which, when determined by the statutory formula, is paid directly to the school district.

AGO 1963 No. 48 (August 13, 1963), available at http://www.atg.wa.gov/AGOOpinions/opinion.aspx?section=archive&id=7670. Consequently, for ASC purposes, the tax found in RCW 54.28.080 is a payment in lieu of property tax and should be functionalized using the PTDG ratio.

In its 2009 ASC Filing, Snohomish included in-lieu taxes in Account 408.1, Other Taxes, and functionalized them to Distribution/Other. Because taxes paid by COUs under RCW 54.28.080 are taxes paid in lieu of property taxes, BPA believes that such taxes should be included under Property or In-Lieu on Schedule 3A and functionalized by the PTDG ratio.

Decision:

BPA will move in-lieu property taxes from Account 408.1, Other Taxes, to Account 408.1, Property Taxes, and will functionalize them using the PTDG ratio.

Table 4.2.5-1: Account 408.1 – Property Taxes:

	Total	Production	Transmission	Dist/Other
As-Filed	0	0	0	0
Adjusted	10,802,237	2,704,497	907,263	7,190,567

Table 4.2.5-2: Account 408.1 – State and Other Taxes:

	Total	Production	Transmission	Dist/Other
As-Filed	29,102,277	0	0	29,102,277
Adjusted	18,299,950	0	0	18,299,950

4.2.6 Schedule 3B: Other Included Items

No direct adjustment.

4.2.7 Schedule 4: Average System Cost

4.2.7.1 Distribution Loss

Snohomish's distribution loss factor calculation is 4.43 percent. See section 4.1.5.1 for details.

4.2.7.2 Contract System Cost

CY 2009 Contract System Cost ($)

As-Filed		Adjusted	
Production	309,328,014	Production	295,261,696
Transmission	45,134,843	Transmission	46,206,396
Less NLSL	0	Less NLSL	0
Total	354,462,857	Total	341,468,092

4.2.7.3 Contract System Load

CY 2009 Contract System Load (MWh)

	Total
As-Filed	7,041,811
Adjusted	7,115,588

4.2.7.4 Average System Cost

CY 2009 Average System Cost ($/MWh)

	Total
As-Filed	50.34
Adjusted	47.99

4.2.8 Purchased Power and Sales for Resale

4.2.8.1 Account 555 - 3-YEAR PP & OSS Work Sheet: Long-Term Purchased Power

Issue:

Whether Snohomish PUD correctly recorded and accounted for its 2009 Lookback Payment[3] from BPA in determining its As-Filed ASC.

Parties' Positions:

Snohomish PUD states that:

- Snohomish is not including Lookback amounts it received in 2009 in its Average System Cost (ASC) calculation because those amounts are being credited to Customer Owned Utilities (COUs) as compensation for the unlawful Residential Exchange Program (REP) Settlement Agreements.

- Using Lookback amounts to reduce a COU's ASC could result in reducing the REP benefits received by public exchanging entities, and increasing an Investor Owned Utility's (IOU) share of those benefits. In effect, including Lookback amounts in a COU's ASC could result in IOUs receiving a benefit for their repayment of an unlawful gain.

See Snohomish PUD's July 2, 2010, response to BPA-SN-FY12-13 and August 24, 2010, response to BPA Issue List, at 3.

- The Lookback Payments and the circumstances surrounding their creation and repayment to the parties are unique, and therefore should not be included in Snohomish's ASC calculation.

- Although BPA's refund to Snohomish of overcharges it levied in past periods contains many of the characteristics of an out-of-period adjustment, the refund also has other distinguishing characteristics of note. For example, the refund is being paid by BPA, the entity against which Snohomish is exchanging, not an independent power producer or power marketer (such as Morgan Stanley or an independent power producer), and thus are different from typical out-of period refunds.

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[3] BPA and Snohomish refer to "Lookback Payments" throughout the discussion of this issue. In the Residential Exchange Program Settlement Agreement Proceeding (REP-12), BPA determined that it would implement the REP for FY 2012–2013 under the terms of the 2012 REP Settlement. The 2012 REP Settlement settles the Lookback-based construct BPA developed in the WP-07 Supplemental ROD, but does so using different terms than referred to by BPA and Snohomish in this section. Specifically, instead of "Lookback Amounts" the Settlement now uses the term "Refund Amounts." While the terms are different, conceptually, Refund Amounts and Lookback Amounts are similar. Both refer to refunds that will be paid to the COUs through bill credits over time for past overcharges. The analysis BPA has performed in this section of the ASC Report is unaffected by BPA's decision to adopt the 2012 REP Settlement.

- Further, the overcharges being refunded were not for the purchase of power, but were ultimately a payment to IOUs for the benefit of their residential and small-farm customers during the 2002–2006 period.

- The refunds remedy excess payments made to IOUs under a benefit program, where the excess payments were recovered by BPA from COUs. Although BPA is the federal entity responsible for administering the benefit program mandated by the Northwest Power Act, the costs of that program are not related to the purchase of power in the same way as a typical, out-of-period adjustment. The 2008 Average System Cost Methodology ("2008 ASCM"), including Endnote j, and the Commission's Uniform System of Accounts do not expressly address refunds for excess payments under a federal entitlement program.

- This leaves BPA discretion to resolve the issue in an equitable and reasonable manner, and is the basis upon which Snohomish advocates BPA omit the return of the overcharges from Snohomish's ASC calculation.

- Lastly, treating the Lookback refund as an out-of-period adjustment, thus reducing Snohomish's ASC, undermines the intent of the REP: to compare the wholesale power costs of an exchanging utility with the costs of power to BPA.

See Snohomish PUD's February 28, 2011, response to comments on the FY 2012/2013 Draft ASC Report for Public Utility District No. 1 of Snohomish County ("Snohomish February Comment"), at 1.

BPA's Position:

The Lookback Payments Snohomish PUD received from BPA in 2009 are an out-of-period adjustment and, as such, should be recorded as a revenue credit to Account 555, Purchased Power.

Evaluation of Positions:

In BPA's WP-07 Supplemental Rate Proceeding, BPA explained that it was conducting the proceeding in order to respond to the Ninth Circuit Court of Appeals decisions in *Portland General Elec. Co. v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007) (finding BPA's 2000 Residential Exchange Program Settlement Agreements unlawful) and *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037 (9th Cir. 2007) (rejecting BPA's allocation of REP Settlement Agreement costs to the PF Preference rate). *See* BPA's WP-07 Supplemental Record of Decision, WP-07-A-05, September 2008, (conformed to errata on February 13, 2009) ("WP-07 Supplemental ROD"), at 9-10. In its response to the Court's rulings, BPA Staff performed an analysis to determine the amount by which the COUs were overcharged for REP settlement costs during FY 2002–2008. *Id.* at 165. In performing this analysis for FY 2002–2006, Staff examined what would have happened in rate setting during the winter of 2000 and spring of 2001 had RPSAs been signed instead of the invalid REP Settlement Agreements. *Id.* Similarly, for FY 2007–2008, Staff proposed to revisit the assumptions and decisions in the WP-07 Final Proposal in a manner consistent with the construct used for FY 2002–2006. *Id.*

To determine the extent of the overcharge in rates that resulted from the REP settlement, BPA compared two calculations. First, BPA calculated the REP settlement benefits that the IOUs received, or would have received, in each year for FY 2002–2008. *Id.* at 165. These amounts are collectively referred to as "REP settlement benefits." *Id.* Second, BPA calculated the amount of REP benefits that each IOU would have received under the REP in the absence of the REP Settlement Agreements, referred to as "reconstructed REP benefits." *Id.* BPA calculated the appropriate differences between the first two components for each year for each IOU, after certain additional considerations. *Id.* These considerations included the treatment of related issues, such as deemer balances, interest on the Lookback Amounts, and the Load Reduction Agreement payments. *Id.* The resulting amounts are called the annual "Lookback Amounts."

Id. Lookback Amounts are provided to BPA's preference customers through credits on their prospective power bills. *Id.* at 266.

Snohomish contends that it should not be required to include its Lookback Credit in its ASC calculation because those amounts are being credited to Customer Owned Utilities (COUs) as compensation for the unlawful REP Settlement Agreements. *See* Snohomish PUD's July 2, 2010, response to BPA-SN-FY12-13 and August 24, 2010, response to BPA Issue List, at 3.

Snohomish is factually correct that the Lookback Credits are a form of compensation for past overcharges by BPA. BPA is making Snohomish whole for these overcharges by providing credits which reduce Snohomish's prospective cost of resources. Snohomish, however, has failed to explain why the 2008 ASCM requires BPA to exclude these credits from its ASC calculation. BPA has thoroughly reviewed the 2008 ASCM and has found no basis for excluding the Lookback Credit from COUs' ASCs. Indeed, the ASCM strongly supports BPA-proposed treatment.

First, the 2008 ASCM requires BPA to use the most up-to-date forecast of BPA's prices for its power when calculating a utility's ASC. 18 C.F.R. § 301.4(a)(5). The 2008 ASCM provides that the cost of BPA's power must be based on "Bonneville's forecast of prices for its products." *Id.* The "price" for a BPA product includes both the rate the utility pays and any adjustments, such as credits or surcharges. In the COUs' case, the "price" of BPA's power is determined by subtracting from the posted rate the amount of credits the COUs' will be receiving from BPA, such as the low-density discount, billing credits, Conservation Rate Credits, and in this case, the Lookback Credit. Reducing the cost of Snohomish's PF purchases by the amount of its Lookback Credit is therefore consistent with the 2008 ASCM and the way BPA treats other rate credits applied to Snohomish's PF Preference power purchases.

Second, BPA's treatment of the Lookback Credit is also consistent with the way out-of-period rate refunds are treated for the IOUs. The Lookback Credit is a refund for an overcharge associated with a prior year's power purchase, in this case PF Preference power purchased from FY 2002–2006. The 2008 ASCM requires that costs and credits be categorized in accordance with the Commission's definitions of such costs. *See* 18 C.F.R. § 301.6(f). The FERC Form 1 requires that offsetting credits or "true-ups" from a previous out-of-period transaction be recorded in Account 555. *See* FERC Form 1 at 327. When completing the Appendix 1, the IOUs include prior-year credits in Account 555, which reduces their power purchase costs and reduces their overall ASCs. Because there is no specific provision in the 2008 ASCM exempting the COUs from recording out-of-period adjustments in Account 555, they too must include out-of-period adjustments (like the Lookback Credit) in the calculation of Power Purchases in the Appendix 1. 18 C.F.R. § 301.6(d). Including the Lookback Credit in the "price" of BPA's power does just that.

Including the Lookback Credit in the COUs' ASCs is also supported by other provisions of the 2008 ASCM. In Endnote j, the 2008 ASCM provides that "all revenues associated with the production and transmission function of a utility" will be functionalized to "production or transmission respectively." 2008 ASCM, Endnote j. The Lookback Credits are refunds associated with overcharges to the COUs from power purchase agreements with BPA, which are part of Clark's production-related function. In summary, the 2008 ASCM requires BPA to treat the Lookback Payments as revenue credits in Account 555 – Purchased Power.

Snohomish argues that using Lookback Credits to reduce a COU's ASC could result in reducing the REP benefits received by public exchanging entities, thereby increasing an IOU's share of those benefits. *See* Snohomish PUD's July 2, 2010, response to BPA-SN-FY12-13 and August 24, 2010, response to BPA Issue List, at 3. In effect, Snohomish claims, including Lookback amounts in a COU's ASC could result in IOUs receiving a benefit for their repayment of an unlawful gain. *Id.*

Snohomish's argument, however, is irrelevant for purposes of determining the appropriate treatment of a rate credit in Snohomish's ASC. The Northwest Power Act requires BPA to establish a utility's ASC based on a methodology established for that purpose. 16 U.S.C. § 839c(c)(7). Under the 2008 ASCM, the proper treatment of Snohomish's Lookback Credit is to include it in Snohomish's ASC as a Production-related credit. BPA cannot ignore the requirements of the ASCM simply because implementing the ASCM could *potentially* increase the IOUs' share of REP benefits. In the same way two wrongs do not make a right, BPA cannot abandon the terms of the 2008 ASCM to avoid benefitting the IOUs. BPA Staff's treatment of the Lookback Credit, which treats these credits as out-of-period adjustments, complies with the 2008 ASCM and is therefore reasonable.

Moreover, even if Snohomish's argument were relevant, BPA's proposed treatment of the Lookback Credit would still be reasonable. Under BPA's proposal, Snohomish's ratepayers are being treated no better or worse than the ratepayers of all of BPA's other COUs who were overcharged during the FY 2002–2006 period. As noted above, Snohomish's ratepayers are being made whole by application of the Lookback Credits to Snohomish's PF Preference rate. Snohomish's proposal, however, would upend this balance by putting Snohomish's ratepayers in an even *better* position than any other COU. In effect, Snohomish is requesting that BPA give it the best of both worlds. Snohomish is requesting that BPA continue to pay Snohomish a Lookback Credit (which reduces Snohomish's wholesale power costs), but at the same time pretend that these credits are not being provided so as to *increase* Snohomish's ASC and, by extension, its REP benefits. The extra REP benefits that Snohomish receives under this scenario are paid for by all BPA ratepayers, including other COUs. As a policy matter, BPA does not believe it either fair or equitable to pretend away an actual rate credit that reduces Snohomish's wholesale power cost (*i.e.*, the Lookback Credit) in order to *increase* Snohomish's ASC and concomitantly increase REP benefits to Snohomish's ratepayers at the expense of all of BPA's other ratepayers. This result is neither required nor mandated by the 2008 ASCM or the Court's opinion in *Golden NW*, and therefore, BPA will not adopt it.

In its comments on the Draft ASC Report, Snohomish reiterates its argument that BPA should exclude the Lookback Credit from the calculation of Snohomish's ASC. *See* Comment of Snohomish PUD No. 1, Re: FY 2012/2013 Snohomish Draft ASC Report, Docket No. ASC-12-SN-01, at 1, February 28, 2011 ("Snohomish February Comment"). Snohomish concedes that the Lookback Credit "contains many of the characteristics of an out-of-period adjustment . . .," but nevertheless argues that special treatment is warranted because of "distinguishing characteristics of note." *Id.* at 2. Snohomish first argues that the Lookback Credit is distinguishable from other out-of-period adjustments because the source of the refund is BPA, the entity with which Snohomish is exchanging, rather than an independent power producer or power marketer. *Id.* Snohomish claims that this makes the Lookback Credit different from "typical out-of-period refunds." *Id.*

Snohomish's claim that the "source" of the refunds matters for determining the inclusion or exclusion of an out-of-period adjustment is mistaken. Nothing in the FERC rules or the ASCM conditions the inclusion or exclusion of an out-of-period adjustment in the utility's FERC Form 1 (or equivalent filing) based on who is providing the credit. BPA has reviewed the Commission's precedent and the ASCM and has found no support for Snohomish's novel concept that refunds provided by BPA are, for whatever reason, excluded from the normal treatment of out-of-period adjustments for ASC purposes. Snohomish has similarly failed to produce any support for its unique view of FERC accounting. Without more, BPA is bound to follow the plain language of the ASCM, and include the Lookback Credit in Snohomish's ASC.

Snohomish claims that BPA's refund is not "typical" of other out-of-period adjustments, but cites no evidence or precedent to support its argument. Snohomish February Comment at 2. To the contrary, BPA believes that refunds from a prior period are a "typical" type of out-of-period adjustment. As explained above, the IOUs record refunds from a prior period as out-of-period adjustments in their Appendix 1 filings, *including refunds provided by BPA*. For example, in PacifiCorp's FERC Form 1, PacifiCorp recorded a refund paid by BPA for $47,083 as an out-of-period adjustment in Account 555. *See* PacifiCorp, 2009 FERC Form 1, at 326-327. This refund was included in PacifiCorp's Appendix 1, and reduced PacifiCorp's ASC by the refund amount. If the IOUs must record BPA refunds as out-of-period adjustments in Account 555, it is reasonable and consistent with the ASCM to require Snohomish and other COUs to record these refunds from BPA in a similar manner. Moreover, the test for determining the appropriateness of a credit in ASC is not whether it is or is not "typical" of other credits, but whether inclusion of that credit is consistent with the ASCM and the FERC Uniform System of Accounts. In this instance, including the Lookback Credit is consistent with both.

Snohomish also cryptically hints that because BPA is "exchanging" with Snohomish, refunds from BPA are not properly includable in Snohomish's ASC. Snohomish February Comment at 2. Again, Snohomish's argument is woefully lacking in support from the ASCM or the FERC Uniform System of Accounts. Nowhere in the ASCM or the Commission's rules does it say that out-of-period adjustments should include all adjustments from other periods *except those adjustments made by BPA.* Had this been BPA's intent in drafting the ASCM, one would expect this counterintuitive prohibition to be expressed definitively in the ASCM or ASCM ROD. It is not. To the contrary, as BPA has explained above, both the ASCM and the FERC Form 1 instructions squarely support BPA's treatment of the Lookback Credit as an out-of-period adjustment.

Snohomish next claims that the Lookback Credit is not a refund associated with the purchase of power. Snohomish February Comment at 2. Instead, Snohomish argues that the refunds remedy excess payments made to IOUs under a benefit program, where the excess payments were recovered by BPA from COUs. *Id.* Snohomish is wrong, however, because the Lookback Credit is indisputably a refund for a power purchase. The WP-07 Supplemental ROD plainly states that the Lookback Credits are being distributed to make whole the COUs that were overcharged for purchases of BPA power at the PF-02 rate. *See* WP-07 Supplemental ROD, at 266. BPA recovered the cost of the "excess payments" to the IOUs from the *power rates* (specifically the PF-02 rate) BPA charged the COUs for *power purchases* during FY 2002–2006 period. BPA, therefore, made the sensible decision to return the refunds to the customers that were overcharged. *Id.* at 282. BPA structured the Lookback Credits as individual bill credits, instead of the a general reduction in the PF Preference rate, for the simple reason that "if a COU was not subject to the inclusion of REP settlement costs *in its rates*, then it should not be allowed to enjoy the return of overcharges through its future rate." *Id.* at 281 (emphasis added). In reaching this decision, BPA was clear that *only* customers of BPA that purchase power from BPA at the PF-02 rate would receive the Lookback Credit. *Id.* at 282. The Lookback Credit, is therefore, indisputably a refund for a purchase of power.

Snohomish next argues that the costs of the REP are not related to the purchase of power in the same way as a typical out-of-period adjustment. Snohomish February Comment at 2. This argument makes little sense. BPA is providing a refund to Snohomish and other COUs because BPA improperly set these utilities' power rates. WP-07 Supplemental ROD at 165. The reason these rates were improperly set was because of BPA's erroneous implementation of the REP, which is one of many programs BPA includes in the rates applicable to the COUs. It is unclear to BPA what connection Snohomish is trying to draw between refunds provided for past power purchases like the Lookback Credit and "the . . . way typical out-of-period adjustment[s]" are made. Snohomish February Comment at 2. Beyond pure assertions, Snohomish has provided no evidence or other citation to support its statement that the Lookback Credit is not a "typical" out-of-period adjustment. As noted before, the Lookback Credit is a refund for past power purchases, which are includable in ASC.

Snohomish next asserts that the ASCM and the FERC system of accounts "do not expressly address refunds for excess payments under a federal entitlement program," and therefore, BPA has discretion to resolve this issue in an equitable and reasonable manner. Snohomish February Comment at 2. BPA concurs that it has discretion to determine the proper treatment of the Lookback Credit. However, this discretion cannot be exercised in a manner untethered to the ASCM. In this instance, BPA believes the Lookback Credit is a refund for power purchases from a prior period. Based on the plain language of the ASCM, and the treatment of refunds under the Commission's FERC Form 1 instructions, BPA believes the Lookback Credit should be included in ASC as an out-of-period adjustment. Snohomish claims that the ASCM and FERC's Uniform System of Accounts do not "expressly address" the Lookback Credit, but this observation does nothing to undermine BPA's treatment of the Lookback Credit. The ASCM and the FERC Uniform System of Accounts were not designed to provide "express" instruction for every conceivable cost or credit a utility could incur. Rather, the ASCM and the Commission's Uniform System of Accounts provide general rules that apply broadly to a full range of costs and credits. As noted above, based on this guidance, the Lookback Credit is squarely a refund associated with a prior power purchase, and as such, includable in ASC as an out-of-period adjustment.

Snohomish argues that BPA's treatment of the Lookback Credit undermines the intent of the REP, which Snohomish states is to compare the wholesale power costs of an exchanging utility with the costs of power to BPA. Snohomish February Comment at 2. Snohomish, however, has it backwards: *Snohomish's* proffered treatment of the Lookback Credit would undermine the intent of the REP because it would artificially inflate Snohomish's wholesale power costs by eliminating legitimate credits from the ASC calculation. For the next two years, Snohomish will receive Lookback Credits from BPA that will unquestionably reduce Snohomish's wholesale power costs. The benefit of these lower wholesale power costs will be experienced by Snohomish's rate payers. Snohomish requests BPA to pretend that these Lookback Credits do not exists for the next two years in order to make Snohomish's wholesale power costs *appear more expensive* than they actually are. In considering which approach follows the intent of the REP, BPA believes that its treatment of the Lookback Credit, which ensures BPA is comparing *Snohomish's real* wholesale power costs against BPA's rates, is closer to the mark.

Snohomish next contends that BPA had three choices for returning the Lookback Credits to the COUs: (1) include the Lookback Credit in the PF Preference rate; (2) provide the Lookback Credit as a credit on power bills; or (3) provide COUs with a lump sum payment. Snohomish February Comment at 2. Snohomish claims option 1 and option 3 creates an "apples-to-apples" comparison, while option 2 creates an "apples-to-oranges" comparison. *Id.* at 3.

BPA notes here that Snohomish's observations regarding the various methods for returning Lookback Credits are not within the scope of this report. BPA's Lookback-related decisions were made in the WP-07 Supplemental ROD, which is currently pending review in the Court. *See* WP-07 Supplemental ROD at 282. What choices BPA had or may have had to structure the Lookback Credit were addressed in the WP-07 Supplemental ROD. BPA will not revisit those decisions here. Moreover, Snohomish's comment is not a challenge to its ASC, but rather a challenge to BPA's treatment of the Lookback Credit *in the PF Preference and PF Exchange rates*. BPA is *not* addressing in this report its development of these rates. Rather, this report only addresses the calculation of Snohomish's ASC under the terms of the 2008 ASCM. To the extent that Snohomish believes BPA is improperly setting the PF Preference or PF Exchange rate for the FY 2012–2013 period, it may make that case in the appropriate rate forum.

Moreover, even if Snohomish's argument were within the scope of this report, Snohomish's argument should be rejected as patently unreasonable. Snohomish insists that the Lookback

Credit be included in the development of the PF Exchange rate in order to create an alleged "apples-to-apples" comparison between the utility's ASC and the PF Exchange rate. *Id.* at 2-3. However, if BPA were to adopt the "apples-to-apples" comparison advocated by Snohomish, and include the Lookback Credit in the calculation of the PF and PF Exchange rates, the lower PF Preference rate would lower the PF Exchange rate BPA charges to *all exchanging utilities, including the IOUs*. Lowering the PF Exchange rate, assuming all other factors remain the same, results in more REP benefits for the exchanging utilities, *including the IOUs.* In other words, Snohomish's proposed "apples-to-apples" approach would have BPA *reduce the refunds due to the COUs that were actually harmed by the PF-02 rates (like Snohomish ratepayers)*, in order to increase the *REP benefits of the exchanging utilities, including the very IOUs that were overpaid in the first place!* BPA does not see why Snohomish would advocate such a position.

Snohomish next contends that the "equivalent amount of electric power" exchanged by BPA with the participating utility must be priced at the same rate as that for general requirements sales to BPA's preference customers (*i.e.*, the PF Preference rate), subject only to adjustment pursuant to section 7(b)(2) of the Northwest Power Act. Snohomish February Comment at 3. Snohomish contends that this is consistent with the notion of "wholesale rate parity" underlying the REP and found in the legislative history for the Northwest Power Act and in prior BPA decisions. *Id.* Snohomish argues that if BPA insists on including Lookback Credits in Snohomish's ASC, BPA must also simultaneously reduce the PF Exchange rate by including payments received by BPA for the IOUs' Lookback obligations. *Id.* at 4.

This comment is also outside of the scope of this report because, again, Snohomish challenges BPA's treatment of the Lookback Credit *in PF rates, not* the treatment of the Lookback Credit in Snohomish's ASC.

Snohomish asserts that it is not seeking "special treatment" or "seeking REP benefits that are not justified by the Northwest Power Act." *Id.* at 4. Rather, Snohomish claims it is merely assuring that Snohomish's residential and small-farm customers are not being unfairly and detrimentally harmed by BPA's choice of how past overcharges are returned to COUs. *Id.* BPA has not treated Snohomish's or any other COUs' customers unfairly or detrimentally by providing the Lookback Credit as an individual refund. Indeed, BPA has taken great efforts to ensure that Snohomish's ratepayers are made whole for the prior overcharges they experienced. On this point, BPA is confused as to why Snohomish continues to pursue this argument when it is so obviously detrimental to the financial interest of its ratepayers. BPA originally considered and rejected Snohomish's "rolled-in Lookback Credit" approach in the WP-07 Supplemental rate proceeding for the sound reason that it would have provided the Lookback Credit to *all* BPA ratepayers, regardless of whether they actually paid PF-02 rates that were overcharged. *See* WP-07 Supplemental ROD, at 282. BPA rightfully determined that rolling in the Lookback Credit to the PF Preference rate would dilute the refunds that should be paid out to the COUs that were actually overcharged (such as Snohomish), while benefitting those not harmed by the REP Settlement. *Id.* at 281. Snohomish did not object to BPA's proposed treatment of the Lookback Credit in the WP-07 Supplemental ROD. *Id.* at 279. Why Snohomish has continued to argue a position that would reduce its current Lookback Credit payments (a refund that can be passed onto all of Snohomish's ratepayers), in order to receive a marginal increase in its REP payments (a payment that may be made only to Snohomish's residential and small-farm consumers), is unclear to BPA.

Decision:

BPA will include Lookback payments of $17,087,443 to the 2009 Appendix 1 Base Year filing as noted in Table 4.2.8.1 below. BPA's rate case forecast of prices for its products will be used in this ASC review, including BPA's forecast of "Lookback" payments.

Table 4.2.8.1: Long-Term Purchased Power

Purchases from BPA included in Power Purchases	As-Filed	Adjusted
PF	$80,630,855	$80,630,855
Slice	$108,579,528	$108,579,528
Lookback	$0	($17,087,443)
Pur Pwr BPA Misc	$0	$112,050
Total	$189,210,383	$172, 234,990

4.2.8.2 Account 555 - 3-YEAR PP & OSS Work Sheet: Long-Term Purchased Power

Issue:

Whether MWh associated with utility-owned generation should be included as Long-Term Purchased Power on the 3-Year PP& OSS tab of the Appendix 1.

Parties' Positions:

Snohomish has not had a chance to respond.

BPA's Position:

Utility-owned generation is not Long-Term Purchased Power, and the MWh should not be included on the 3-Year PP& OSS tab of the Appendix 1.

Evaluation of Positions:

The FERC Uniform System of Accounts states that Account 555, Purchased Power, shall include the cost at point of receipt by the utility of electricity purchased for resale. Since utility-owned generation does not fit this definition, the MWh should not be reported in Long-Term Purchased Power on the 3-year PP& OSS tab of the Appendix 1.

Decision:

BPA will remove the MWh associated with the three utility-owned generation projects (Jackson Hydro, Everett Cogeneration, and Woods Creek Hydro) from Account 555, Purchased Power.

Table 4.2.8.2 Long-Term Purchased Power

Megawatt Hours Purchased	As-Filed	Adjusted
Jackson Hydro	394,246	0
Everett Cogeneration	221,418	0
Woods Creek Hydro	845	0
Total	616,509	0

4.2.9 New Resource Additions

4.2.10 New Resource Additions: Reclassification

Issue:

Whether renegotiation of an existing contract constitutes a new resource addition.

Parties' Positions:

Snohomish included in its ASC Filing as a new resource addition costs associated with the renegotiation of an existing contract for a thermal cogeneration resource.

BPA's Position:

The costs reported by Snohomish as new resource additions are costs associated with renegotiation of an existing contract and therefore do not meet the requirements for a new resource in the ASC Forecast Model.

Evaluation of Positions:

In its Appendix 1, Snohomish included as a new resource addition costs associated with the renegotiation of an existing contract for a thermal cogeneration resource. In response to Data Request BPA-SN-FY12-20 and BPA Issue List, Snohomish stated that the costs for a thermal cogeneration resource were incremental costs for an existing contract that was substantially revised by agreement of the parties in April 2010. *See* Snohomish's Response to BPA Issue List, August 24, 2010, at 4. The resulting additional costs are incremental to Snohomish PUD's 2009 Base Year actual costs. *Id.* The expected output rating of this plant is 37.0 aMW. The contract revisions do not provide any additional annual energy to the District. *Id.*

The 2008 ASCM ROD states that the costs of resource investments (production or generating), transmission investments, long-term generating or transmission contracts, pollution control and environmental compliance investments, plant rehabilitation investments, and hydro relicensing costs and fees will be included when determining an exchanging utility's Exchange Period ASC, subject to meeting the materiality threshold. 2008 ASCM Final ROD, at 43. Relicensing costs included in intangible plant or regulatory assets and liabilities are subject to the same functionalization rules and procedures as all other regulatory assets and liabilities. *Id.* Changes or replacements to existing fuel contracts are not allowed. *Id.* The costs of new replacement gas contracts actually incurred will be included in future Base Period costs. *Id.*

The issue of allowing true-ups to a utility's forecast ASC was discussed extensively during the 2008 ASCM consultation process, and was rejected for the following reasons. First, allowing true-ups would increase the complexity and administrative burden of the REP. *Id.* Second, ASCs are established prior to BPA setting its power rates. *Id.* This is necessary because ASCs are a major determinant of whether the section 7(b)(2) rate test triggers and the resulting Utility PF Exchange rates used to calculate REP benefits. *Id.* If BPA were to allow true-ups to ASC, there would be a disconnection between the ASCs used to establish rates and the ASCs used to calculate actual benefits. *Id.* Third, BPA is establishing ASCs for two years only, so actual costs for calculating ASCs would be updated every two years. *Id.* During the discussions with stakeholders, there was general agreement that establishing ASCs for two-year periods reduced the need for true-ups. *Id.* Finally, BPA is concerned that the terms of any future replacement fuel contracts would not be known during the ASC review period when ASCs are established, so any forecast of replacement costs would be highly speculative. *Id.*

The costs included by Snohomish for the cited thermal cogeneration resource are incremental costs for an existing contract and therefore a true-up to an existing resource. Such costs cannot be included as a new resource addition. However, the incremental costs of the contract revision actually incurred will be included in future Base Period costs and thus included in future ASCs.

Decision:

BPA will exclude the costs of the revision of an existing thermal cogeneration resource contract from Snohomish's ASC established in this Draft ASC Report. However, the incremental costs of the contract revision actually incurred could be included in future Base Period costs and thus included in Snohomish's future ASCs.

4.2.11 New Resource Additions: Materiality

Issue:

Whether the removal of the costs of a revision of an existing contract (4.2.10.1) from Snohomish's Group 2 new resource addition affects the materiality of the Group 2 resource.

Parties' Positions:

Snohomish has not had an opportunity to comment on this issue.

BPA's Position:

When the costs of the revision of an existing contract (4.2.10.1) are removed from Snohomish's Group 2 new resource addition, the materiality of the Group 2 resource is reduced to 1.88 percent, which is less than the 2.5 percent threshold specified by the 2008 ASCM.

Evaluation of Positions:

As noted in Section 4.2.10.1 above, Snohomish incorrectly included the costs of a revision to an existing cogeneration resource contract in its Appendix 1. When the costs of the contract revision are removed from Snohomish's Group 2 new resource addition, the materiality of the Group 2 resource is reduced to 1.88 percent. The 2008 ASCM 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). Because the removal of costs of the contract revision from Snohomish PUD's Group 2 new resource addition changes the materiality of the Group 2 resource to 1.88 percent, the Group 2 resource is less than the 2.5 percent threshold required by the 2008 ASCM.

Snohomish would have the opportunity to regroup resource additions to meet the 2.5 percent threshold; however, Snohomish does not have any additional resources to group. *See* Section 3.4., Timing of Materiality for New Resource Additions, of this report.

Decision:

BPA will remove Snohomish's Group 2 new resource addition.

4.2.12 New Resource Additions: Reclassification

Issue:

Whether the integration of three separate projects constitutes a single new resource addition and, if not, whether each project meets the materiality test.

Parties' Positions:

Snohomish reported as a grouped new resource the costs associated with the purchase of resource output from three resource projects located in BPA's Balancing Authority Area.

BPA's Position:

The costs associated with resource integration are not new resources and should not be included in the list of new resources as a grouped resource in the Appendix 1.

Evaluation of Positions:

The 2008 ASCM 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.

2008 ASCM § 301.4(c)(4). Snohomish stated in response to a BPA data request that it is purchasing resource output from three resource projects in BPA's Balancing Authority Area. *See* Snohomish's Response to BPA Issue List, August 24, 2010, at 3. The above cost represents the annual incremental integration cost for Snohomish on a yearly basis compared to 2009 Actual Base Year costs. *Id.*

Each resource integration service purchase should be considered an individual new resource addition when it is used to integrate power from different generating resources.

Pursuant to the 2008 ASCM, each new resource addition must stand alone and meet the 0.5 percent threshold. Such resource additions, when grouped, must meet the 2.5 percent threshold. Therefore, each individual integration contract must meet the 0.5 percent threshold, and grouped resources must meet the 2.5 percent threshold.

When BPA Staff made this evaluation, none of the integration contracts was material.

Decision:

The separated resource integration projects do not meet the 0.5 percent threshold and will not be included as a new resource in the ASC Forecast Model. These costs, however, could be included in future in Snohomish ASC filings.

4.2.13 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 Snohomish'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").[4]

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

[4] 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.

presumption that potential NLSLs are NLSLs for purposes of calculating ASCs in the Draft ASC Reports. *See* IOU Comments at 2.

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 Staff 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 Staff 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.

<u>Decision:</u>

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

<u>Issue:</u>

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.

<u>Parties' Positions:</u>

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.[5]

[5] 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 staff 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 Staff'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.

<u>Decision:</u>

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' Rate Period High Water Mark 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' Rate Period High Water Mark 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:

G. ASC Determination for COUs that elect to execute Regional Dialogue HWM Contracts.

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' Rate Period High Water Mark 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 Taxes

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.

Decision:

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

Issue:

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

Parties' Positions:

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.

BPA's Position:

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.

Evaluation of Positions:

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.

Decision:

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

Snohomish's ASC for FY 2012–2013, with the loss of a resource before the Exchange Period, is $46.67/MWh. This result is based on adjustments made to Snohomish's ASC Filing.

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 Snohomish for FY 2012 and FY 2013.

This Final ASC Report is BPA's determination of Snohomish's FY 2012 and FY 2013 ASC based on information and data provided by Snohomish, 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 Snohomish'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 ASCM and generally accepted accounting principles, and fairly represents Snohomish'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
DOE/BP-4308 ▪ July 2011